STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

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

APPLICATION OF READ AND STEVENS, INC., FOR AN UNORTHODOX INFILL GAS WELL LOCATION AND SIMULTANEOUS DEDICATION, CHAVES COUNTY, NEW MEXICO

CASE NO. 11,514

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
JAMI BAILEY, COMMISSIONER

October 29th, 1996

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission, WILLIAM J. LEMAY, Chairman, on Tuesday, October 29th, 1996, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

October 29th, 1996
Commission Hearing
CASE NO. 11,514

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E X H I B I T S

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A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 12:50 p.m.:

CHAIRMAN LEMAY: Okay, we shall continue here by calling Case 11,514, which is the Application of Read and Stevens for an unorthodox infill well location and simultaneous dedication of acreage, Chaves County, New Mexico.

This case will be heard *de novo* by the Commission, and I shall call for appearances.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin.

I'm appearing on behalf of the Applicant, Read and Stevens, Inc.

I'm also appearing on behalf of an offset operator that supports the Applicant. That company is Matador Petroleum Company.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

MR. BRUCE: Mr. Chairman, Jim Bruce from the Hinkle law firm in Santa Fe. I am representing UMC Petroleum Corporation.

CHAIRMAN LEMAY: Thank you. Any other appearances?

Will those witnesses who will be giving testimony please stand and raise your right hand?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

Mr. Chairman, on behalf of Read and Stevens, we're asking the Commission to review this case and to try to persuade you to agree that it is necessary in this particular reservoir for Read and Stevens to have the opportunity for a protection well.

It will be our evidence, our testimony and our conclusion that Read and Stevens needs a protection well in the southwest quarter of Section 26, and in the absence of that well, waste will occur and correlative rights will be violated.

To set the stage for you, we have an unusual circumstance, where if you'll look at the handout I've given you -- it's the plat -- I've identified two sections. There's Section 26; that's the Read and Stevens section. Section 35 is the UMC section.

Despite the fact that it is undisputed, and the testimony will show that the experts agree that these two sections are competing for reserves in the same common source of supply, the same interval, those two sections are in fact in different pools. It's one of the oddities that occasionally occurs as we manage these pools, to in fact find that one common source of supply is divided in such a way that despite the competition, two different rules apply.

In Section 26 there are two wells that we will talk about. There's the Harris Federal Number 8 well up in the northwest quarter section of 26, and then there's the Harris Federal 4 down in the southeast quarter.

In Section 35 we're going to talk about two of the UMC wells also in communication with the Read and Stevens wells. The UMC well up in the northwest corner is the White State 2, and down in the southeast corner that's the White State 1.

In the Section-26 area, that has been developed, produced and subject to the Buffalo Valley-Pennsylvanian gas rules. You may remember that pool, because twice a year you visit that pool; it is a prorated gas pool.

South of Section 26, in 35, in Section 35, you have the Diamond Mound-Morrow Gas Pool. It is not a prorated gas pool.

When you look at Buffalo Valley, the rules are something of a novelty. They have 320-acre gas spacing. They provide, however, that standard well locations are no closer than 990 feet to the outer boundary of a 320-acre spacing unit.

But they also provide, under one of the rules, that they preclude -- unless you grant an exception, they preclude wells from being located in either the northeast quarter section or the southwest quarter section.

The circumstances are such that Read and Stevens requested permission to drill the new well. The new well is the Harris Federal 11 -- that's the proposed name -- spotted on the map. That well is a standard footage from the common line with UMC. It's located 990 feet back.

The problem is, in order to drill it in the southwest quarter we need an exception because it's off-pattern, if you will. In Section 35, the rules for that portion of the pool down there are statewide 320-acre gas spacing and the common rules that you're familiar with, where you can drill anywhere in the spacing unit provided you're not closer than 1980 from the end or 990 from the side boundary.

The evidence will show you that White State 2 well is about 1980 feet south of the common section line where that section adjoins the Read and Stevens property.

That sets up the rules, and that sets up the fact that historically, those four wells have competed in the same common reservoir. The UMC wells were drilled before the Read and Stevens wells.

The Division Examiner at that time was David Catanach, and I've distributed to you a copy of the Examiner Order. It's Order R-10,622. It's from a May 16th, 1996, hearing. Mr. Catanach agreed with a number of our propositions, and our evidence will demonstrate to you that we presented evidence and he concluded that the Number 11 well in the southwest quarter, in fact, was necessary, that it's likely and probable that it will recover gas reserves that might not otherwise be recovered, that in fact it was necessary in order to protect Read and Stevens' correlative rights.

And then Mr. Catanach had a dilemma: Mr. Catanach was presented at the Examiner case with an incomplete case. Neither I nor the expert witness I'm about to present to you were involved in that matter. But the record reflects that Mr. Catanach was given a geologic presentation, he was given decline-curve analysis, which gave some extrapolated ultimate gas recoveries per well, and that was the end of the story.

The dilemma for Mr. Catanach was that he was not given gas-in-place calculations by either engineer that testified. There was no attempt to scientifically present a complete reservoir-engineering study from which Mr. Catanach or anyone else could have determined relative share.

The relative share, as you know, under correlative rights is the opportunity to produce your just and equitable share of recoverable gas underlying your tract in relation to the pool's recoverable gas.

And so what we have done is, we have fixed that problem, and we are here to tell you the rest of the story.

Mr. Terry Payne has been retained by Read and Stevens at my request to do a reservoir-engineering study. Mr. Payne has done the volumetrics, which Mr. Catanach did not see. Mr. Payne has reanalyzed the decline curves and very carefully determined the estimated ultimate gas recoveries.

In addition, Mr. Payne has also modeled the reservoir. He has taken all the available engineering data and conformed it and matched it with historical information so that his reservoir simulation now can give you an accurate and reliable forecast of what to do now.

We will request that you do this, that Mr. Payne will demonstrate to you that at a relevant point in time there now remains 8.4 BCF of gas to be recovered between Sections 26 and 35 and that the correlative-rights share that's apportioned to Section 26 is 5 BCF, that the appropriate apportioned share of remaining recoverable gas to which UMC is entitled in Section 35 is 3.4 BCF.

Mr. Payne will conclude for you that in the absence of the protection well, two things are going to happen.

There's going to be about a half a BCF of gas that's not going to get recovered. The four wells are not going to get it.

In addition, without the Read and Stevens protection well, there's going to be a shift in gas reserves, a significant shift. The correlative rights at issue is 3 BCF of gas. Without the protection well, it will be his conclusion that 3 BCF of gas shifts -- 3 BCF of gas that Read and Stevens is entitled to goes to UMC. The White State 2 and the White State 1 are going to take the gas.

If we are allowed to drill this location as an exception to the rule, we get to produce gas that would not otherwise be recovered, and we get to balance the inequity so that we will get our relative share.

It is not Mr. Catanach's fault that the presentation was incomplete. He attempted to deal with a penalty. He issued a 50-percent penalty on the location. A matter for you to consider is what to do. Mr. Catanach was faced with a precedent, to the best of my knowledge and recollection, because I do not remember a disputed case that's resolved based upon the well being at a standard-footage location, and yet off-pattern. And the dilemma for him was to figure out a penalty.

We will ask you to remove the penalty; that's what we're here to do. We want the penalty off. Without the penalty, then, our correlative rights are protected, UMC is not harmed and equity is established.

We will give you the engineering study of Mr. Payne, and that's something that Mr. Catanach did not get to see, and we apologize for not showing it to him, but we have it now.

CHAIRMAN LEMAY: Thank you.

Mr. Bruce?

MR. BRUCE: Very briefly, Mr. Chairman, we of course disagree. We believe this reservoir is adequately developed as is, and a new well will not produce any additional reserves.

If this new well is allowed to be drilled without a penalty, it will give Read and Stevens a competitive advantage over UMC, and therefore, at the very least, a penalty is required.

Look at the map Mr. Kellahin handed you. If you look at Read and Stevens' acreage, it's got wells in the northwest and southeast quarter. If you look at UMC's acreage, it's got wells in the northwest and the southeast quarter. You look around that, to the north in Section 23 it's the same thing. In Section 25 it's the same thing. Read and Stevens is not the only one that might be affected by offset wells.

Currently, the production from Section 26 is about a million a day. The production from Section 35 is about a million a day. They're at a competitive equilibrium right now.

If you allow this well to be drilled in the southwest quarter, because of the geologic form of this reservoir, it will give -- there will be oriented drainage to the north and the south, and it will give Read and Stevens an advantage over UMC. Like I said, Read and Stevens isn't the only one who suffers from this.

If you look at Section 34, there are two wells there drilled which drain UMC's acreage. There's wells in Section 6 to the south, which probably drain the southwest quarter of Section 35, yet UMC can't go drill its well in the southwest quarter because under current OCD guidelines or OCD rules it cannot -- it needs a secret handshake, in effect, to go in there and drill and simultaneously dedicate wells in the southwest quarter to a well that's over in the southeast quarter.

It would either have to alternately produce those wells under current -- under the last few OCD hearings I've done on this, or it would have to severely restrict production. That's just the way it goes. It happens sometimes.

As it is, both of these sections are going to produce a huge amount of gas, no one is at a competitive disadvantage at this point, and to allow the well without penalty would give UMC a competitive disadvantage.

Thank you.

CHAIRMAN LEMAY: Thank you, Mr. Bruce.

MR. KELLAHIN: We'd like to call Mr. Terry Payne.

TERRY D. PAYNE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Terry Dean Payne, and I'm a consulting petroleum engineer.

Q. Where do you reside, sir?

A. I reside in Austin, Texas.

Q. When and where did you obtain your degree?

A. I obtained my degree from the University of Texas at Austin in May of 1985.

Q. On prior occasions have you testified as a petroleum engineer with expertise in reservoir simulation and testified before, in fact, this Oil Conservation Commission?

A. Yes, sir, I have.

Q. Were you a witness in the original Examiner presentation of this issue to Examiner Catanach back in May of 1996?

A. No, sir.

Q. Following the entry of that order, were you retained by Read and Stevens to perform a reservoir study with regards to this topic?

A. Yes, I was.

Q. Were you provided any agenda or preconceived conclusions that you were supposed to attempt to reach?

A. No.

Q. Did you conduct your study in the fashion that you usually do, to be totally independent as a consultant and to use the best efforts of your science and your ability to give us an accurate and reasonable conclusion with regards to what to do?

A. Yes, sir, I have.

Q. Have you completed all that work?

A. Yes.

Q. In order to complete your work, did you have available to you all the necessary geologic and engineering data by which you could perform the work that you performed?

A. I suppose you always would love to have more data, but in this case we have about 30 years of production history and quite a bit of pressure data, so we certainly have adequate data to describe the reservoir.

Q. Is the kind of reservoir study you performed for Read and Stevens the kind of study that you routinely perform for numerous clients?

A. Yes, sir, it is.

Q. And is this the type of information that you present to regulatory bodies upon which to make decisions?

A. Yes, it is.

Q. On the basis of data, do you find any difficulty that you could not resolve based upon the lack of adequate data?

A. No, sir, there's -- As we described before, there's ample data to get a good description of this reservoir.

Q. Have you completed your study?

A. Yes, I have.

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

A. Yes, I do.

Q. As part of your study effort, did you review all the hearing exhibits presented by UMC and Read and Stevens before Examiner Catanach?

A. I did.

Q. And did you read the transcript and have you read the order issued in that case?

A. Yes, sir.

MR. KELLAHIN: We tender Mr. Payne as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Chairman LeMay) Let's turn to the topic of the Examiner Order, Mr. Payne. I'm going to show you a copy of that order. As you reviewed the Order and went about analyzing the data presented to Mr. Catanach, describe for us what if any significant issues did you see with the presentation by both UMC and by Read and Stevens.

A. Well, the most significant issue that was lacking in my mind is that the Examiner was not given information on what was the current gas in place on either section, Section 26 or Section 35. He was really not provided with what was there originally, and certainly wasn't provided with what was there today. Nor was he provided with information that would lead him to -- or allow him to determine what was recoverable under either section as of this date.

Q. Why is that an issue?

A. Well, that seems to be the test of whether or not a well like this is required, is, in my mind, and I think in the Commission's mind, looking at what is recoverable under each Section today, also looking at what the existing wells will recover, and if there is a shortfall, then the additional well is required. If the existing wells are capable of recovering all of the recoverable gas on either section or on the section in question, an additional well would not be required.

Q. We are not talking about trying to balance historically with total pool withdrawals for each of the parties?

A. No, sir, we're not. We're talking about looking at the situation as it exists today and making certain that equity is carried forward from this point, not trying to make up any past drainage in the past.

Q. We're looking at prospectively what portion of remaining recoverable gas is each of the properties entitled to recover?

A. That's correct.

Q. All right. As part of your investigation, did you examine the geology presented and the engineering data available from which to reach a conclusion about whether all four wells in this two-section area were competing for reserves in the same common source of supply?

A. Yes, we did. We looked at a much-expanded area that we'll talk about in a minute, but our focus was on the two sections in question.

Q. Is there any doubt in your mind that Examiner Catanach was correct when he found, in fact, that these four wells in these two sections were competing in the same common source of supply?

A. No, sir, there's no doubt about that.

Q. All right. We're dealing in lower Pennsylvanian reservoir?

A. Yes.

Q. As part of your study, did you look for a drive mechanism in the reservoir?

A. Yes, I did.

Q. What have you concluded is the drive mechanism of the reservoir?

A. It's a depletion drive gas reservoir.

Q. We don't have an active water drive or a water component to the reservoir that affects your calculations or your conclusion?

A. No, sir.

Q. Is there a structural component to the reservoir that's of such a magnitude that it affects what you do and how you did it?

A. No, sir, structure is not a controlling factor.

Q. All right. Examiner Catanach looked and concluded that in relationship to 26 and 35, that in a simple sense the distribution of reserves for which the wells were competing was apportioned, generally, in the west half of both of those sections?

A. That's correct.

Q. Do you find any evidence to the contrary?

A. No, sir, I think the geology in that respect was in pretty good agreement that the channel thickens on the west side of the sections and thins on the east side.

Q. When you look at the bottom of page 3 of the order, the Division has concluded, based upon the estimates of ultimate gas recoveries and some hypothetical drainage circles, that there was a distribution of drainage area and estimated ultimate recoveries.

Independent of that presentation, you have done your own work, have you not, sir?

A. Yes, sir.

Q. And independently, then, you have by various methods determined how each of these wells, in fact, has produced, will produce and what they will ultimately recover?

A. Yes, sir, that's correct.

Q. All right. When we look at the existing Harris Federal wells in Section 26, there are two wells that have access to the reservoir. There's the Harris Federal 8, up in the northwest corner --

A. Yes.

Q. -- and the Harris Federal 4 in the southeast quarter.

Which of the two wells is the better well?
A. The Harris 8 is in the center of the channel and is a much better well.
Q. When we look at Section 35 and the two UMC wells, which is the better well, and why?
A. The White State 2 is a better well than the White 1, although they're both very good wells. The 2 is a better well.
Q. Are these two wells competing for reserves among each other?
A. The two White State wells?
Q. All four wells.
A. All four wells are competing for the same reserves.
Q. There's absolutely no doubt about it?
A. No doubt about it.
Q. Okay. When you look at the pressure data that we will examine, is there a pressure advantage that is currently enjoyed by one operator over the other?
A. Yes, there is.
Q. What is the advantage, and in what direction?
A. Well, one thing we will show is that the reservoir pressure on Section 35 is lower than the pressure on Section 26, so we have a migration of gas from Section 26 to 35 as we sit here today.

Q. As you've analyzed it, is there any reasonable probability that Read and Stevens can recover their apportionate share of recoverable gas in 26, in the absence of the Federal 11 proposed well?

A. No, Read and Stevens will suffer a shortfall. That gas would be recovered on Section 35 if the Harris 11 were not drilled.

Q. Can that well be put in one of the two standard quarter sections and still achieve the objective of protecting the section from drainage?

A. No, it cannot, not fully protect it, no.

Q. The proper place, in your judgment as a reservoir engineer, is where, to put the Federal 11 well?

A. It needs to be over in the southwest corner at the proposed location. We've examined other locations, and this appears to be the optimum location.

Q. As part of your analysis, were you -- did you reach a conclusion as to whether or not, apart from the competition, the addition of the Federal 11 well would recover gas out of this pool that would not otherwise be recovered?

A. Yes, sir, there is a small amount of incremental reserves. It's something on the order of a little bit less than a half a BCF. But there is some gas that would not be recovered by the existing wells.

Q. Half a B sounds like a bunch to me, Mr. Payne. It may be small to a fellow like you that deals with these fancy reservoirs, but it's about a half a B, right?

A. Half a BCF. And in, roughly, today's dollars, two dollars an MCF, it's a million dollars' worth of gas. It's a significant amount of gas. We'll show that the study area that we've looked at has about 86 BCF in place, so that's where I term it a small amount, but certainly not insignificant.

Q. Small in relation to what other wells were doing among each other?

A. That's correct.

Q. When you put -- Have you analyzed the economics of this?

A. Yes, sir, we have.

Q. As part of your reservoir study, it's not solely pointed to gas volumes; you also put a cost component to this, do you not?

A. Well, business decisions are important, and that's how you make the business decisions.

Q. Were you able to satisfactorily develop the necessary data on which to make accurate volumetric calculations of original gas in place?

A. Yes, sir, we were.

Q. Were you able to develop data and information by which to construct accurate decline curve analysis of all the relevant wells?

A. Yes, sir.

Q. And based upon the decline curve analyses, were you able within reasonable engineering discretions to estimate ultimate gas recovery for each well?

A. The decline curves are useful for the current scenario. In terms of evaluating what will happen with the proposed well, you need to go a step beyond that. But we did look at the decline curves, and that's an important part of what we did.

Q. Without reservoir simulation, is there any reasonable way to determine or forecast, one, where to put the well in the section, and, if you put it there, what the proper position within the quarter section should be?

A. I suppose there are other ways to go about it. I think it's the most accurate, it's the most reliable, and it's the method we've chosen. And with the amount of data that we have, it, I think is the way to go. It's something that we'll describe how we did, and it's certainly the most reliable method to use.

Q. In order to maintain equity in terms of future competition among the two operators for remaining recoverable gas, in your opinion, is it necessary to penalize the Federal 11 proposed well?

A. No, sir, a penalty is not required, is not necessary.

Q. Let's look at your study, Mr. Payne, and have you show us what you did and how you did it.

A. Okay.

MR. KELLAHIN: The Exhibit book, members of the Commission, is simply marked as Read and Stevens Exhibit 1. Mr. Payne and I will go through each of the dividers. We'll be referring to a divider in the numerical order, but that simply refers to the divider and not the exhibit number.

Q. (By Mr. Kellahin) All right, let's start with a quick checklist of what's going to be in the exhibit book, Mr. Payne. If you'll turn behind the table of contents in Exhibit 1, that gives us our list of topics that you have within the book?

A. Yes.

Q. All right. Let's turn past that and look at Tab 1. Let's go to the conclusions about what you have determined will happen in the absence of drilling the Federal 11 well.

A. Okay.

Q. Show us what you conclude.

A. Okay, this is in a nutshell what will happen if the Harris Federal 11 is not drilled. And we look at

Section 26, the top line. The current gas in place on Section 26 is 6.2 BCF. Of that gas, 5 BCF is recoverable. There's 1.2 BCF on that section that's just unrecoverable.

The two existing wells, the Harris 4 and the Harris 8, are going to recover only about 2.5 BCF. So there's 2.5 BCF that are unrecoverable by the existing wells as we sit here today.

On the other hand, Section 35 currently has 4.3 BCF in place. Of that, 3.4 is recoverable. But the two existing wells are going to recover 6.4 BCF. Obviously they're draining some other tract. A lot of that comes from Section 26 to the north, the Read and Stevens section.

So in a nutshell, without the drilling of the Number 11, there's 2.5 BCF that will be unrecovered by the existing wells on 26, and on Section 35 the two wells will recover 3 BCF more than the recoverable gas on their section.

Q. If UMC is worried about their share of recoverable gas, should they be worried?

A. Yes, sir.

Q. Why?

A. Well --

Q. I'm sorry, I said UMC. I meant Read and Stevens.

A. Well, Read and Stevens should be worried. As this exhibit shows, there's definitely a shortfall. Their two wells are just not going to recover the existing gas --

Q. Is it to the advantage of UMC to maintain the status quo, then?

A. Yes, it is.

Q. By about 3 BCF?

A. By about 3 BCF.

Q. All right. Let's turn to the question that was bothering Mr. Bruce about what's happening in the two pools in terms of exception locations, off-pattern well approvals. Identify and describe for us the plat that's shown behind Exhibit Tab Number 2.

A. Okay, the map in Exhibit Tab 2 is actually a pull-out exhibit. It's just folded in half and put in that map pocket for simplicity.

But we've colored in yellow a number of wells that are not necessarily exception locations, but they're wells that are drilled either in the southwest or the northeast corner, and those are -- of a particular section. Those are wells that are not orthodox under the current Buffalo Valley rules. And you can see there's a great number of such locations. This Harris Federal Number 11 would be the first to receive a penalty based on the unorthodox location. It would be the only one to do that.

Q. Do you see any necessity to maintain the form of the rule which says, I'm sorry, Charlie Read, but you can't drill in the southwest quarter of 26?

A. Well, not in this instance. There are certainly geologic reasons for drilling over in the southwest corner. We'll go over those. I don't think that's in big dispute. There are engineering reasons in terms of recovery and economics. The well is necessary to recover gas that otherwise won't be recovered.

And as you went over in the opening, again, what appears to have happened here is that the pools have just through development grown together. They were originally thought to be separate. They certainly look to be a common source of supply now, so we have a prorated pool in one section, producing from the same reservoir with an unprorated pool just to the south.

Q. Let's turn to the reservoir data. If you'll look behind Tab 3, let me have you discuss and describe that information.

A. Okay, this is just a reservoir data sheet to give some very basic reservoir engineering parameters.

And the depth of this reservoir is approximately 8700 feet. The initial reservoir pressure was about 3400 p.s.i. Reservoir temperature was about 165 degrees, still is. Gas gravity of .65. Impurities were minimal. The initial gas formation factor was 216 standard cubic feet -- or cubic foot -- and the original gas in place from volumetric determination was about 86 BCF.

And that 86 BCF is in about a 15-square-mile study area that we are looking at. And we can -- we'll show it to you, define it a little better on a future exhibit. But that's about a 15-square-mile area that we have chosen as a study area, that is representative of Sections 26 and 35.

Q. Before I forget to ask you, we've focused on two sections, but the study area was the 15-square-mile area. Why did you have such a large area for the study area?

A. Well, I probably should have talked about that on the previous exhibit. If we could go back to Exhibit 2, I'll define exactly where the study area is.

We started up in Section 15, which is northwest of Section 26. We went from 15, 14 and 13, going to the east, those three sections. Then we came all the way down past Sections 34, 35 and 36, down into Sections 1, 6, 5 and 4, below Section 35.

So we chose that area because basically we knew we were going to do a simulation study, we knew that we would have to cut the model off at some point. We looked at the EURs of a number of the wells in the area, and that seemed to be a good place to stop it for two reasons.

It appeared that the channel that we were studying tended to die out in east and west directions at about that point.

And to the north and south it looked like maybe we were getting into some overlapping channels or something, because the area around this study area, the EURs for these wells, were very small, either zero or a tenth of a BCF or a half a BCF. Something very small in terms of the average recovery for the field.

So those looked to be good reservoir limits, and that was the basis for our choosing and defining this particular study area.

Q. What's wrong with simply taking the two sections and adding a spacing unit all the way around the two sections and make that your study area?

A. Well, there appears to be very good communication up and down this channel, and just imposing limits on the outside of these two sections would impose some boundary effects that you wouldn't properly characterize in the model if you manually just put a boundary there yourself. There are things going on in the reservoir that you would not account for.

Q. By creating a larger area, have you in effect moved the influence of the boundary effects far beyond how it might change the relative share in Sections 26 and 35?

A. Yes, sir, we have. We've certainly insulated them from any boundary effects of the model. We've moved them where we can to a reservoir limit, and that is in most of the area.

But there to the northeast and southwest, we've moved it to areas where there's very little gas movement, because the EURs are so small for those wells, there's just not much gas moving there. So that's a good place for a gas boundary also.

Q. In terms of the volumetrics, there are some geologic values and parameters used in the volumetrics, are there not?

A. Yes, there are.

Q. How were you able to satisfy the component to give you an appropriate shape and size for the container by which you've calculated the volume?

A. Well, I worked together with Mr. Brannigan who provided the geologic interpretation, but we have a great amount of production data from these wells, and we also have a good deal of pressure data that we'll look at in a minute, that from a material balance study very clearly defined the size of the reservoir.

So we looked at it from a volumetric standpoint, from a material-balance standpoint, and then also did the simulation study. And all three of those came to a number of about 86 BCF.

Q. When we turn behind the first display in that section, what do we then see?

A. This is the basis for our initial reservoir pressure of 3400 pounds, and it's a DST taken in the Harris Federal Number 2 upon completion in 1975. And it shows that the initial pressure was right at 3400 pounds.

Q. Okay, the next display after that?

A. The next display after that is a color tab where we show the initial reservoir pressure data based on the state completion forms, the C-122s.

And the basic point to take away from this exhibit is that you can see up until the early 1980s, early 1982 or 1983, we were still finding a number of wells up in the 3400-pound pressure range. We were seeing a number of wells that were being drilled in areas that were not yet been drained.

Since about 1983, we really haven't drilled any wells in the field that are not -- or that are penetrating areas of the reservoir that have not been affected to some degree by drainage. What that indicates to me is that there is at least some degree of communication throughout the reservoir. Some areas are being drained better than others, but there's some degree of communication throughout this channel system.

Q. Okay, what happens next?

A. The next page is simply just the backup tabular data for that plot.

Q. Are you satisfied that you had enough reliable pressure data to give you a good control parameter as you continued with your work?

A. Yes, I am.

Q. We have a distribution of data points over appropriate periods of time that if you're going to match the pressure, you have a good data point to match to?

A. Yes.

Q. What happens when we turn behind Tab 4?

A. Well, Tab 4 is a study area, P/Z plot. And Read and Stevens, in August and September of 1993, went out into the field and did long-term pressure buildup surveys in nine wells. That's about half the wells in the study area.

Q. When was this, Mr. Payne?

A. August and September of 1993.

Q. 1993?

A. Yes, 1993.

Q. All right.

A. With that data -- and it was analyzed by Schlumberger, modeled, verified. I think the results are very sound and very reasonable.

We took that, we knew the production of the study area at that point in time. We also had these pressures from the buildup surveys. So with that data we constructed a study area, a P/Z plot. And as you can see, this line happens to be just a least-squares fit from the initial reservoir pressure through the data that was obtained in 1993, and it also shows an original gas in place of about 86 BCF.

So with the average reservoir pressure, or average study-area pressure in 1993, combined with what we knew the original study-area pressure to be, we were able to construct this plot and also give us a really good indicator of original gas in place.

Q. You've used a catch-phrase: least-squares fit?

A. Yes.

Q. Now, is that a statistically valid methodology to apply in order to put a decline over -- a decline line on here by which you can forecast ultimate gas recovery?

A. Well, it --

Q. I'm sorry, gas in place --

A. Yeah.

Q. -- we're looking at gas in place.

A. Yes. The least-squares fit just means that I haven't sat here and decided where to put this line; it's a mathematical computation of fitting that data. And, you know, I guess it's like decline curves: One person might draw it one place, another person somewhere else. But this is actually a least-squares fit, it's a mathematical fit of that data.

Q. All right. Okay, what's after that?

A. The next page is simply the backup tab for that. It shows the wells that were surveyed, the actual pressure that was determined, the Z factor and the calculated P/Z point for each well.

Q. All right. You now move into the volumetric calculations, if you will?

A. Yes.

Q. All right. If we turn behind Tab 5, take us through this display.

A. Okay. What we're showing here is the original gas in place and the recoverable reserves on each of the two sections, Sections 26 and 35. We -- If we just take the top line, we move through the volumetric parameters of reservoir volume from the net-pay map, the average porosity and water saturation, the initial gas formation volume factor, and with those values we can calculate the original gas in place on Section 26, and that's 18.6 BCF of gas originally in place.

We now know -- We anticipate that the abandonment pressure will be about 250 p.s.i. for the field, abandonment gas formation factor is about 15. Therefore, a calculated recovery factor -- or the recovery factor you calculate is about 93 percent of the gas in place for that reservoir. That means that of the 18.6 BCF in place, about 17.4 BCF is recoverable on Section 26.

Now, if you go through the same exercise for Section 35, they originally had 12.9 BCF of gas in place, and 12.0 BCF of that is recoverable.

So there's about 1.2 BCF on Section 26 that is not recoverable, and about .9 BCF on Section 35 that's not recoverable.

Q. The volumetrics attributable to Section 26 and 35 are derived from the study area that had 86 BCF in it?

A. That's correct.

Q. All right. Okay.

A. So you can see these two sections are an important part. We've got over 30 BCF of the 86 total in place. So these are two key sections.

Q. Turn behind Tab 6 and have you go through the analysis, then, and this is without the proposed Federal 11 well?

A. That's correct.

Q. What happens?

A. Well, we knew from a volumetric standpoint what was in place and what was recoverable. The next step was to see, what are the existing wells truly going to do?

So we list all of the wells in the study area, and in the second column we list their current cum production in BCF, and out of the study area that total is about 55 BCF.

Then we looked at a couple of different techniques.

We looked at a rate-versus-cum plot on each well, and all of those are shown just behind here. I won't go through each one of them, but they're there to look at.

And we also looked at the publicly available P/Z data from the state shut-in test, the 24-hour shut-ins. And they're in reasonable agreement with the rate-cum plots. It looks like, bottom-line number, that the existing wells are going to recover about 71 BCF of the 86 in place.

But we just looked at it two different ways: a rate-cum and a P/Z, to see -- And you can look at each of the individual wells; they're all in general agreement.

Q. And you have the declines plotted for each of the wells in the study area, and that's what's shown behind the summary sheet?

A. That's correct.

Q. All right. When we look at the two techniques, the rate versus cum and the P/Z technique, and it looks to be your -- what? About a half a BCF, or less, difference in applying the two techniques?

A. Yes.

Q. Is that a difference of significance?

A. No, it's not, and again, the P/Z data, you know, is from the state 24-hour shut-ins. That's not the most reliable data in the world to look at. But we did want to look at it, and it does give you general agreement with the rate-versus-cum plots.

Q. So what's the point when you look at the two different techniques and you get about 71 BCF?

A. Well, the real point here is that you can look at it a couple of different ways, and we'll break it down to the two important sections here, 26 and 35, but we're coming at the reserves a couple of different ways, before we even get to the simulation study, that give us about the same number in terms of recovery for the existing wells.

Q. What's that beginning to tell you as a reservoir engineer?

A. Well, you're feeling more and more confident about the conclusions that you're reaching as you go along. If you're looking at it from a number of different ways and the results are similar, it gives you a warm fuzzy about where you're headed with the conclusions.

Q. All right Let's go to Tab 7 and look at the display behind Tab 7.

A. Okay, this does --

Q. We're now moving into decline curve analysis on the two sections?

A. Yes, we are.

Q. Okay.

A. Again, we break it down, instead of just looking at the two sections, the components of those in the individual wells. But on Section 26 we have the Harris 4 and the Harris 8, and we show the cum production from that section to date, and that's 6.1 BCF. And then we show the decline curve EUR, which was in general agreement with the P/Z of about 8.7. So on Section 26 it looks like we're going to recover about 2.6 BCF of additional gas if the Harris Federal 11 is not drilled.

Now, we had previously calculated that on Section 26 there was 17.4 BCF of recoverable gas, but the two wells are only going to get 8.7. Obviously, we have an 8.7 BCF shortfall. So that tells you right there that there's a tremendous shortfall in terms of reserves that will be unproduced from the existing wells.

Now, you contrast that with Section 35. The White 1 and White 2 have combined to produce about 9.1 BCF. They're 3 BCF ahead of us in terms of current cum. And again, we're not trying to go back and fix that; we can't do that. What we are looking at is, where are we today? But they are 3 BCF ahead.

Their decline curve, EUR for the two wells is about 14.2, so they're going to get a little over an additional 5 BCF.

But the section recoverable reserves we had previously calculated were only 12 BCF. So obviously they're going to drain 2.2 BCF off of another section. They're going to get 2.2 more than is recoverable under their tract.

Q. Are you absolutely persuaded that's right? Is there any kind of mistake about that?

A. Well, at this point in time, this was just volumetrics, decline curves. We did want to carry it a step further and --

Q. So you don't know yet for sure, but under this decline-curve analysis, you've concluded that they're going to recover more than 2 BCF more than their share of recoverable gas underneath the section?

A. Well, what concerned me at this point was the big shortfall in Section 26.

Q. Okay.

A. It seemed too big to be reasonable. And it wasn't until we did the simulation study, realized the magnitude of communication and where the gas was truly moving in the reservoir, that it all fell into place.

Q. Okay.

A. But we were convinced at this point that there was a shortfall on Section 26.

Q. All right. You've worked through the volumetric methodology, you've looked at the decline-curve methodology. You're now ready to move into the next chapter, and that is to perform reservoir simulation?

A. That's correct.

Q. All right, let's start with the first data after Exhibit Tab 8 and look at the model input data.

A. Okay. This does just describe the input data that we used for the model. We used a single-phase gas-simulation model. It was a grid orientation of 24 cells east and west and 43 cells north and south, for a total number of grid blocks of 1032. Each one was 660 by 660. And we had the 22 wells from the study in the model.

Our net thickness came from the net-pay map. Porosity and water saturation came from log analysis. Our initial pressure was, as we've seen before, 3400 pounds, gravity of .65 and temperature of 165.

And when we initialized the model, it also had at about 86 BCF of gas in place, and that agreed with the material-balance number and with the volumetric number.

Q. Let's turn to Exhibit Tab 9 and have you identify and describe this display.

A. This is just to give you an areal viewpoint of the grid as it overlaid the net-pay isopach. And each of the model cells were assigned a value that corresponded to the average thickness of that cell. The program takes a five-point average; it gets the value at each corner and in the center, and then assigns the average of those numbers as the value for that cell.

And there's a 3-D picture of it. It's a little bit crowded on the next page, but it -- just to generally show you that -- the relative size of the cells and the relative thickness in terms of net pay of each cell. And this 3-D representation does correspond with the net-pay map.

Q. Did you attempt to utilize the UMC net-pay map that they introduced to Examiner Catanach back in May of 1996 to see what you could calculate to be the gas-in-place volume using the UMC map?

A. Yes, sir, we did.

Q. And what did you conclude?

A. Well, we -- Their map was very close. They got about 80 BCF of gas in place, and that's certainly within --

Q. Using their map, you calculated, they didn't calculate?

A. I'm sorry, that's right. Using their map, we calculated -- Using the same parameters that we used for our map, or our calculations, we determined that their map had about 80 BCF of gas in place. So you're really in very good agreement there between the two maps.

We do have a couple of problems with some picks that they made to the north, and we can certainly talk about those. There's obviously some errors from their map up to the north that give it a little bit smaller value. We were curious why is theirs smaller. We went well by well by well to see what the difference is, and up in the area to the north of the map there's a couple wells where they've just got too little pay.

Q. All right. And once you made the adjustments to the values in their map, you could understand why they only had 80 BCF in place --

A. Yes, sir.

Q. -- in the study area?

A. That's correct.

Q. Now we're comparing study area, the same --

A. That's right.

Q. -- the same area?

A. Our map and their map in Sections 26 and 35 were really pretty close. There was not that much variation in those two sections.

Q. All right. When we go to Tab 10, what happens now?

A. Well, once we had initialized the model and we had the producing wells in there, we went through the history-match phase. And basically these are the results of the history match.

What we're representing here, up through the current time period, there are four curves that are depicted on here. Let's take them one by one.

The solid red curve are the actual monthly production rates for each well.

The blue circles are then the simulated production rates, both during the history-match phase and the production -- I'm sorry, prediction phase of the study. We then have some green squares -- Let me stop right there. Both of those values correspond with the left-hand Y axis, so you've got monthly gas production on the left hand, and it corresponds with the red lines which are actual rates, and the blue circles which are the simulated rates. And as you can see here, we've got a very good match on the production for the Harris Federal Number 4.

On the right-hand Y axis, we have reservoir pressure, and the green dots are actual reservoir pressures for the individual wells. The point that's shown -- well, and then we have actually -- The pink X's are then the simulated reservoir pressures, which also, of course, correspond with the right-hand axis. But you've got actual rates, simulated rates, actual pressures and simulated pressures.

And you can see here on the Harris 4 -- we won't go through each and every one of them, but there is a pressure point that's a little bit obscured in August of 1993. It's the green dot that lays really directly under the pink line, and that's just signifying that we did match the reservoir pressure in the simulator on the Harris 4.

This then also shows the blue dots extending on out into the future and the pink X's extending on out into the future, and it shows you the predicted rates for that well and the predicted reservoir pressure decline for that well.

But that's the match that we achieved for the Harris Federal Number 4, which is the southernmost well in Section 26.

The next page shows you the match that we achieved for the Harris 8, which is the northernmost well in Section 26, and again there is a green dot at the initial completion of the well, but it's under the pink line. And then in mid-1993, we again see a green square that's again covered by the pink line or the predicted pressures.

We -- and again, we won't go through all of these, but --

Q. Turn down to the White State ones, though.

A. Okay. Well, we've got all of the wells, the Harris wells and a couple of others, where we had the measured pressures and those match very well, we matched all those very well.

Q. So you're matching to pressure, and in doing so you're honoring the historic production?

A. Well, we're matching both production and pressure.

Q. Okay.

A. The production is an input value. We give the well a target rate to try to make that is the actual production. Obviously, if it can't make that rate in the model, you've got something wrong in terms of gas in place, or not enough pressure there.

But where it does achieve the target rate that you've given it, your next check on, do you have the proper gas there at the proper time, is your check on pressure. So you've got a rate check and a material-balance check with your rates and pressures.

Q. Okay.

A. The last two wells in the display behind Tab Number 10 are the White State Number 1 and the White State Number 2. Now, obviously we didn't have any long-term pressure buildup data on those wells, but we have compared these matches to the 24-hour shut-in, the state shut-in tests, and I have those exhibits if we want to look at them. But we have a very good match in terms of pressure on those two wells also.

Q. The last sheet in this section, before we go to 11, is a table, a summary table?

A. That's correct.

Q. Describe for us what this shows.

A. Well, these are the EUR, the estimated ultimate recovery for each of the same 22 wells that we've been looking at so far, as a result of the simulation study.

Now, in general, we're in pretty good agreement in terms of the rate-cum and the P/Z. But you do notice that the overall total is a little bit higher. I think that one thing that's happening is that the model recognizes the fact that some of these wells, the recoveries are going to -- or the rates are going to flatten out later in their life. I think with the rate-cum plots that we looked at before, that wasn't really built in; we're doing more of an exponential-type decline. But the model does recognize that the rates are going to flatten out as you get more and more feet in from the matrix.

But in general, the agreement is pretty good between the simulation recoveries and the decline recoveries. And again, this is all without the proposed well. We did not put the proposed well into the model at this point.

Q. Okay, let's put the proposed well in.

A. Okay.

Q. If you'll turn behind Exhibit Tab 11, let's see what happens.

A. Well, behind Exhibit 11 is a projection of what the proposed well, the Harris 11, would produce if it came on essentially November 1st, and it looks like it would make between 1.3 and 1.4 million a day, initially. That rate would decline down pretty rapidly to less than a million a day.

But it also shows the extrapolation of what the reservoir pressure would do as the well is depleted. And you can see that there has been some depletion of this area by the existing wells. There has been communication, there has been drainage.

In the area that we would propose to drill the well, the pressure has declined from about 3400 pounds initially, down to below 1500 pounds. So that area has been depleted to some extent, but we'll show you in a little bit, it's certainly not as well drained as the other areas in the field.

Q. When you talk about the proposed well, you're putting it in the model in the position Read and Stevens would like to drill it in the southwest quarter?

A. That's correct.

Q. It's in the appropriate cell, then, to be in that location?

A. It's in the appropriate cell, and it's important also to note that we're allowing it to produce at the rate we predict that it will come on at, and it's not a penalized allowable; it's the rate without penalty.

Q. All right. When you look at its initial starting rate, what kind of volume on a daily basis are we looking at for the proposed well?

A. It's a little over 1.3 million a day.

Q. All right. And the spacing unit under the proration system, I think, gets 1.1 million a day currently?

A. That's the top current allowable, that's correct.

Q. And you get to produce -- you get to carry a six-times-over production allowable in southeastern New Mexico, so would this well under this assumption have to be curtailed as a nonmarginal well?

A. I don't think so, because within about three or four months we're down to the allowable rate. So in a very short period of time, the decline gets down either at or below the allowable, and then we can start making up the overproduction.

Q. All right. So the forecast or the assumptions made in the model as to what it would be allowed to produce at initially is consistent with what it could do?

A. That's correct, that's correct.

Q. And there was no need to impose a limitation in the well, in the model, because of some allowable issue?

A. That's correct.

Q. All right, what happens then? Having done that, what's the result?

A. Well, the next page is a tab much like we've been looking at before, and you see that we've added in the proposed well, down near the bottom, and the estimated ultimate recovery for the proposed Harris Number 11 is about 3 BCF.

Now, we won't go through each of them side by side, but that recovery does come from the Harris 8 and the Harris 4, as well as slight effects on some of the other surrounding wells. But we've got a tab here in just a second that describes the exact impacts on Section 26 and Section 35.

Q. Okay, let's turn to Tab 12 and have you identify and describe for us what you're showing in this section.

A. Okay. Tab Number 12 is simply an economic projection using the forecasted production rate and capital costs to drill the well of $472,000, and the expected operating costs, and we used a gas price held flat of $1.80. And it shows that the net present value, discounted at 10 percent, is just under $1.5 million. So it's certainly an economic well to go drill with the current cost estimates and price schedule.

Q. We talked earlier about the current pressure differential between the Harris 8 and the White State 2, and I think there was about a 350-pound differential. Have you plotted the differential?

A. Yes, we have.

Q. Let's turn to Tab 13 and have you discuss and describe for the Commission the distribution of the reservoir pressure.

A. Okay, one of the questions that kept coming up at the Examiner hearing was, what is the reservoir pressure, either at either of the wells or at the proposed location, and that data was just not presented.

But what this shows is that at the Harris Number 8, Section 26, the reservoir pressure is about 1150 pounds. Down in Section 35, at the White State 2, the reservoir pressure is closer to 950 pounds. So there's almost a 200-p.s.i. differential between those two locations.

Now, in the proposed location, which we've designated with the arrow at the proposed well, we would expect to encounter a reservoir pressure just over 1200 pounds. So that's an area that is not being as effectively drained as, obviously, the locations near the two wells. And you just see that the pressure is higher in Section 26 than it is on Section 35. And even if these wells were shut in, there would be a migration of gas over to that section, Section 35.

So there is an imbalance in pressure between the two, and it's primarily because of the -- again, that Section 35 has had 9.1 BCF produced off of it; there's only been 6 BCF produced off of Section 26. And that's resulted in this imbalance in reservoir pressure.

Q. Without the proposed well at its location, will there be any way to minimize or arrest the pressure differential that's currently enjoyed by UMC?

A. There does not appear to be any other way.

Q. You have a footage relationship between the two wells and the proposed well on the bottom of the scale?

A. Yes.

Q. What do you have here?

A. Well, we're just pointing out that obviously the proposed well is much closer -- or closer than -- to the Harris 8 than it is to the White State Number 2, and it, being 990 off the lease line, would be much closer to our well.

Q. Let's go to the final tab, behind 14. You've got a summary page here?

A. Yes.

Q. Let me have you give us the summary.

A. Okay. This is it, the summary format, the entire conclusion of our study. And if we start up at the top, without the proposed well -- we'll just go through each column for Section 26 -- we show that originally there was 18.6 BCF of gas in place. The cumulative production from that section was 6.1 BCF, but the current gas in place is only 6.2. So obviously there's been some drainage off of that section.

Of that 6.2, 5 BCF is recoverable. The existing wells will get 2.5. That's a 2.5-BCF shortfall. That's without the proposed well.

On the other hand, Section 35, 12.9 originally in place. They've produced 9.1, 3 BCF more.

But currently in place, they only have 4.3 BCF. Of that, 3.4 is recoverable. But their two existing wells are going to recover about 6.4 BCF. Therefore, they have about 3 BCF that they're going to produce off of another tract, drain from other areas.

Now, if we move down to the bottom of the page, you see the results with the proposed well.

In Section 26, original gas in place is the same, cum to date is the same, current gas in place and recoverable gas are all the same as before. The only thing that's different is the last two columns. And the remaining reserves for the existing wells, the two existing wells, plus the proposed well, is 4.9 BCF.

So we go from 2.5 BCF of recoverable reserves without the proposed well to 4.9 with the proposed well. And again, we have 5 BCF remaining recoverable on our tract. So even with the proposed well, at a nonpenalized rate, we're still going to leave .1 of a BCF of recoverable reserves on that tract.

Now -- And again with the proposed well, let's look at the effects on Section 35. The original gas in place, cum production, current in place and current recoverable all remains the same as before, but their remaining reserves for the existing well dropped from 6.4 BCF down to 6.1. But they still are producing 2.7 BCF off of another tract. Now -- So the effect on their wells is, they get .3 of a BCF less, but they still get 6.1 BCF of gas, when all that's recoverable on their tract today is 3.4. So they still get in excess of the recoverable gas on their tract.

So bottom-line number is that without the Harris Number 11 there will be 2.5 BCF that's confiscated from the tract. With the Harris Federal 11, at an unpenalized rate, all but a tenth of that can be produced by the Harris

Number 11.

Q. Did you analyze the situation of what happens if the Commission rejects your study and requires that the well be drilled in an on-pattern location? In other words, you can't drill in the southwest quarter?

A. Yes.

Q. Have you examined what happens if you're required to put it over in the southeast quarter with the Harris Federal 4 well?

A. We did. And again, we're talking about moving the well about two units to the east, to get it over in an orthodox location. But again, the Harris Number 4 is currently producing in that section, so obviously it has drained some of the reserves there. Plus, we know we're moving to an area of much poorer reservoir quality. You've got a half-a-BCF, roughly, well in that section already, in that proration unit.

But we did look at just moving barely over into the edge of that, and instead of getting 3 BCF, the well would recover about 2.7 BCF. So it would get .3 of a BCF less.

It also comes on at a lower rate, and what that allows is for more confiscation to occur to Section 35; if our protection well is not there to eliminate that drainage, they get more in Section 35, not to mention it's about a $360,000-less-net-present-value well, than the proposed location. So we lose reserves. And obviously bottom line is, we lose about $360,000 in net present value.

Q. You're able to conclude, then, the 50-percent penalty that Mr. Catanach placed on the well at this location is not necessary?

A. It's not necessary, and again, he just didn't have the data to make that decision at that point in time. What he was looking at was an inequity in production rates from Section 26 versus 35.

But what's really important is, what is the recoverable gas today on the two sections? And I think we've shown that there's a big imbalance in that. There's much more recoverable gas on 26 than 35.

Q. If the 50-percent penalty stays in place, what happens to the equity?

A. Well, some of it -- Well, it's obviously a better situation for UMC. The well does protect some of the area from drainage, but at this restricted rate it can't protect all the drainage. So there's still a shift down to Section 35 at the penalized rate.

Q. You examined what UMC's engineer presented as his method for a penalty at the Examiner hearing?

A. Yes.

Q. It was a penalty based on rate, was it not?

A. I believe there was a rate component to it, but it was, I think primarily, a penalty based on distance to lease lines.

He was, if I understand it correctly, coming up with a 65-percent penalty for the proposed well, because we were 990 off the lease line, and their existing White State was 1980 off the south section line. So if you take the 990 over the -- the 990 from our well to the lease line, and divide that by the 990 plus the 1980, you get a ratio of about a third. And so he was proposing about a 65-percent penalty on the Harris Number 11, based on distance, well distance and section distance.

Q. Did that penalty have anything to do with the share each section should have of remaining recoverable gas?

A. I don't think so. There was certainly no discussion of that at the last hearing, and I don't see that in the formula.

Q. Summarize for us, Mr. Payne what you would recommend to the Commission.

A. Well, the results of our study are that there is recoverable gas on Section 26 that will not be recovered by the two existing wells on the tract. A majority of those reserves will be recovered, but they will be recovered by the wells in Section 35 and other wells in the area.

If the Harris Number 11 is allowed to be drilled at the proposed location and not given a penalized allowable, that well will, to a large extent, produce the remainder of the recoverable reserves on this tract.

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

We move the introduction of Read and Stevens Exhibit 1.

CHAIRMAN LEMAY: Without objection, Read and Stevens Exhibit 1 will be entered into the record.

Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Payne did I understand you correctly that if this well is moved to the east and drilled at a standard location in the southeast quarter, it would still recover about 2.5 BCF?

A. It would still recover approximately that amount, according to our interpretation. According to UMC's interpretation, it's even in a thinner, poorer-quality -- or poorer section of the reservoir. But that's according to our interpretation, yes. But it still does allow confiscation by the White State wells.

Q. Now, you said you calculated gas in place based on UMC's net-pay map. What did you come out with, figures per section?

A. The UMC map had about 16 BCF of gas in place on Section 26, and about 13.1 BCF of gas in place on Section 35. I don't know if the Examiners have that map available to them --

MR. KELLAHIN: They do not, Mr. Payne.

THE WITNESS: -- but -- and we'll talk about that if we need to.

The reason that there is a difference -- we get 18.6 BCF on Section 26; the UMC map gives you about 16 BCF -- is there that a couple -- two wells -- We have an exhibit on it, if we need to show it -- where they give significantly less net pay just north of Section 26 than is clearly there. And what that causes is, it shrinks their contouring on the northern portion of Section 26, and results in about a 2.5- to 3-BCF shortfall on the UMC map, compared to the Read and Stevens map.

So we're -- Really, I think we're in pretty good agreement on geology, with the exception of the problems on the UMC --

Q. (By Mr. Bruce) And your gas-in-place calculations are based on Mr. Brannigan's map; is that correct?

A. That's correct, that's correct.

Q. And so if his map is incorrect, then your calculations are incorrect?

A. Well, you know, we looked at it volumetrically, we looked at it from a material-balance standpoint, and we also got a very good match in the reservoir-simulation study. So we've come at it from three different directions, and the geologic study ties very well with the production data and with the pressure data. So I feel pretty good about the interpretation.

Q. Okay, but if his map is wrong, your calculations are incorrect?

MR. KELLAHIN: I'm not sure the gentlemen are talking the same thing. He's asked you if your calculations were on the Read and Stevens map introduced at the hearing --

Q. (By Mr. Bruce) No, no, I'm saying --

MR. KELLAHIN: -- aren't you?

Q. (By Mr. Bruce) -- if Jim Brannigan's geologic mapping is incorrect, then your total oil -- excuse me, gas, in place for these two sections is incorrect?

A. Well, I would -- If it's incorrect, I would not be as confident. But we've come at it from a couple of different ways. We've also got pressure data that indicates to us what the amount of gas in place is. I would not be as confident in the interpretation if his map were incorrect, though.

Q. Do you have accurate pressure data from Section 35? Any buildup tests?

A. We don't have any buildup tests, but we can make these exhibits if you want to make them. I have exhibits much like what were presented in Tab Number 10 that display the 24-hour state shut-ins along the calculated or simulated pressure line, and for both of those wells they're in very good agreement.

And I don't mean to be long-winded. We do not have any buildup surveys on those two wells.

Q. Okay. Is 24 hours sufficient? I mean -- I don't know which tab it is here, Mr. Payne. Tab 3, Tab 3.

Obviously -- You know, it's taken a long time for pressure to go down in certain parts of this pool, like there's not a perfect communication, is there?

A. In Tab 3?

Q. Under -- Behind Tab 3, I believe it is.

A. Okay.

Q. Yeah. Your initial reservoir pressure data map with the red dots on it?

A. Yes.

Q. I mean, this isn't a straight-line decline, is it, reservoir-wide?

A. No, there are -- It's not a tank that everyplace in the tank has the same pressure at this point, no.

Q. Okay, so the best data would be long-term pressure-buildup data from Section 35?

A. That would be the best data, but we have examined the only data that's available, and recognizing that it may not be as high as it would be if it were allowed to do a buildup survey, it's at least representative of what the pressures are in that section.

Q. But your simulation depends upon the accuracy of the pressure data?

A. Well, we've looked at the initial pressures in each well. But the confidence in the match is very highly dependent upon the actual buildup surveys that were conducted by Read and Stevens in the study area. Those were the pressures that we were most concerned about matching.

Q. Now, although you didn't present it, you said you used Jim Brannigan's map, geologic net-pay map. Is that the same map that was used at the Examiner hearing?

A. There are some slight revisions in the map from Mr. Brannigan's previous testimony.

We initially started out looking at that map, and it appeared to us from a material-balance standpoint and from a simulation standpoint that that map was slightly too big. It had too much gas in place.

We then looked at the UMC map, and it was too small. And we wanted to see what the problems were with the UMC map, and that's when we discovered the problems to the north. But the UMC map in this study area, again, had about 30 BCF in place.

Q. Okay, and the map you used isn't in these materials?

A. Yes, it is. It's --

MR. KELLAHIN: -- behind Exhibit Tab 9?

THE WITNESS: -- 9, yes, that's the map that we used.

Q. (By Mr. Bruce) Where -- You know, I'm kind of lost here. Where are the section boundaries? Where is -- Where are the wells? I can't tell.

A. Well, we can -- I can certainly determine that for you.

Q. Well, I'd like that. I mean, there's numbers thrown on here. I mean, this could be in another township and range for all I care.

A. Well, it's not. We can -- basically, if you count across eight divisions -- Actually you count across nine on the first one, and that would be the eastern -- I'm sorry, that would be the western boundaries of Sections 26 and 35. And if you count over eight more, you would then be at the eastern boundaries of 26 and 35.

Q. Is there a way to place on here the wells in these two sections so we can talk about this for a minute?

A. Yes, we can do that. I'd be happy to do that.

MR. BRUCE: Mr. Chairman, could we take a break just for a second? I mean, I can't tell --

CHAIRMAN LEMAY: Yeah, I understand what you're saying.

THE WITNESS: I'd be happy to do that. That's no problem.

CHAIRMAN LEMAY: Let's take our 15-minute break, and we'll come back.

(Thereupon, a recess was taken at 2:12 p.m.)

(The following proceedings had at 2:30 p.m.)

CHAIRMAN LEMAY: And we shall continue.

MR. KELLAHIN: Mr. Chairman, with Mr. Bruce's consent, I would like to have the opportunity to take Mr. Payne on direct again and hopefully overcome the mapping problem that we've all given you.

What I'd like to do is take a few minutes, and I think what we'll do is, we'll simply put in the isopach that will give you the picture and show you the locations in addition to what you're looking at there.

So if Mr. Bruce has no objection, I'd like to take a few minutes --

MR. BRUCE: That's fine.

DIRECT EXAMINATION (Continued)

BY MR. KELLAHIN:

Q. Mr. Payne, during the break we took -- or you were asked to take the isopach that's shown with the grid, which is behind Tab 9, and to position on that grid the location, or the approximate location, of the four wells that are in question in Sections 26 and 35. Have you done that, sir?

A. Yes.

MR. KELLAHIN: Mr. Chairman, I have submitted that to Counsel and to the Commission as Read and Stevens Exhibit 3.

Q. (By Mr. Kellahin) First of all, let's talk about what appears to be a distortion when the computerized grid is put on the isopach, and then it's duplicated in a hard copy for us to look at. Is that a flaw or a mistake or otherwise weakness in the system?

A. No, it's not, it's -- first of all, it's -- The paper is 8 1/2 by 11, so it's trying to draw a -- represent a square on a rectangular sheet of paper. But this is just a schematic representation of the grid as it was overlaid on the net-pay isopach. If we want to truly look at the positions of the wells in relation to the contours, the best place to do that is from the net-pay map.

Q. Well, let's go back to that, then. I have shown you what we propose to introduce as Read and Stevens Exhibit 2. Do you have that before you?

A. Yes, I do.

Q. Is this the net-pay isopach map that you utilized for the geologic parameters that went into the model?

A. It is, yes.

Q. All right. And where did you get this?

A. This was done by Mr. Jim Brannigan, and his initials are shown at the bottom of the page.

MR. KELLAHIN: All right. Thank you, Mr. Chairman. We would move the introduction of Read and Stevens Exhibits 2 and 3.

CHAIRMAN LEMAY: Without objection, Exhibits 2 and 3 will be admitted into the record.

CROSS-EXAMINATION (Resumed)

BY MR. BRUCE:

Q. I just had a couple of questions here, Mr. Payne.

To the best of your knowledge, since the last hearing and this hearing, have there been any new wells drilled in this, say, four-section, six-section, nine-section area, which would give you any new data to change the geologic interpretation, or give any -- a geologist a basis to change the geologic interpretation?

A. There have been no new wells drilled in the area, but there has been an integration of geologic study with the engineering study, and that is what has resulted in the revisions in the map.

Q. Okay. Looking at your Exhibit 3 and -- well, either -- the exhibits marked 2 and 3, especially on your Exhibit 3, you've got, oh, up in Section 26, the Read and Stevens section, a big area of 30 and 40 feet. What well control is there in that area of 30- and 40-feet-thick pay to justify that?

A. Well, there's the well in the southeast of Section 23 that has 36 feet of net pay, so that is the control, that's -- you know, gets 36. We contour up to 40.

Q. Now, which well is that? The --

A. It's the well in the southeast of Section 23, that's labeled with 36 feet of pay. That's easiest seen on the net-pay map, Exhibit 2.

Q. And that's the well you're relying on?

A. Well, again, I didn't contour the map, I didn't draw the map, but I believe that's the well that Mr. Brannigan is relying on to contour up to 40 feet. The log calculations give you 36 feet of pay, and it looks like he's just carried the contour up to 40. You know, and then he -- well -- I'm not trying to mislead you, but I think that's what he's done.

Q. Now, you mentioned your engineering model. Can the direction of the sand deposition change and the

\thickness change due to the engineering model?

A. Well, the engineering model is very helpful in defining the size of the reservoir, yes, and the pressure buildup surveys are helpful in determining some reservoir boundaries. So there have been a number of things that have been integrated into this picture that helped define the size and shape of the tank.

Q. And once again, you don't have any pressure data from Section 35 to go on for that change, do you?

A. Well, we do have the --

Q. -- three-year old?

A. -- state tests, the --

Q. The three-year-old, short-term pressure tests?

A. Well, they're short-term, but there's a number of them historically, and our pressure trends were going right through the trend of the pressures. So we don't have a test beyond 1993, but through the entire life of the well we were certainly on trend with those pressures.

MR. BRUCE: I think that's all I have, Mr. Chairman.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. The concern over the gas that will not be produced in Section 26, if no well is drilled in the southwest quarter, showing the communication between these two different pools, where it's one common source of supply, it extrapolates that concern should be covering the entire area that you examined with your study. Are you not going to propose that the pool boundaries are changed to accommodate this information you now have?

A. Well, it's not something that we're proposing at this point in time, to change the pool boundaries. But there may be additional locations in the future that are justified to drill, such as the Harris Federal 11, to recover more reserves. But at this point in time, I don't think it's our immediate intention to change the pool boundaries.

Q. I notice that there are a lot of Read, et al., leases all through that northern area, 26.

A. North of 26, yes, ma'am.

Q. The implication is that the extra production from the UMC wells comes from Section 26. How have the other surrounding sections, particularly to the south, been ruled out as sources of that extra production?

A. It's not really my intent to rule them out as sources of the extra production. Really, what we're attempting to show is that without the existing -- without the proposed well, that there will be a shortfall of recovery on Section 26.

Because Section 35 seems to have such a -- it seems that it's going to produce such a larger amount than what's recoverable on its tract, that it's the most likely source of that drainage. But it may be a combination of a lot of area south of Section 26.

But the real focus -- We haven't really tried to define what is the exact wells that are causing the drainage. The real focus has been to show that there are reserves on Section 26 that will not be recovered by the existing wells and that this well, if it's allowed to be drilled, will recover just those reserves. It does not seem that it's going to have the impact of draining reserves from another tract. It seems like it will recover just the reserves -- calculations show it will recover just the reserves on Section 26.

Q. Do you believe that the Read and Stevens Harris Fed Number 8 is draining any of the section above, Section 23?

A. Well, there are two wells up in Section 23 producing, and it -- It would depend on the timing of when those wells came on, the current rates, the pressures. I think that there is some degree of communication between Section 23 and 26. As to where the exact no-flow boundary is between those two wells, I really haven't tried to define that, but there is some degree of communication between 23 and 26.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, let me get clear in my own mind what happened here.

A. Yes, sir.

Q. This is a single-phase simulator?

A. Yes, sir, that's correct.

Q. And then on Tab 9, that 3-D map, it indicated, if you recall, several layers, different colors, but you only simulated one; is that correct?

A. Yes, sir, the layers represent thicknesses. So for instance, the green is from zero to 10 feet, the blue is then from 10 to 20. So it's just a color-coding of how thick that individual cell is.

Q. Okay, so --

A. Yes, sir, it doesn't represent multiple layers, that's correct. It generally corresponds with the picture up on the top of the --

Q. Yeah, I remember.

A. Yes, sir. Okay.

Q. I've got you.

And then what is the constraint on the pressure-rate equation? Is it pressure or gas rate?

A. The model is controlled by the back-pressure flow equation, Q equals C times PR squared, reservoir pressure squared --

Q. This isn't a -- Surely this is a finite-difference model, isn't it?

A. Yes, but the -- I was trying to explain. We give it two constraints: the rate constraint, or a rate target, and then a minimum flowing bottomhole pressure. So there is a rate target that if it can make that without going below the minimum flowing bottomhole pressure, it does that, but it's --

Q. Okay, but if you're above the pressure rate, it's a constraint?

A. That's correct, that's correct.

Q. And then the -- So when I look at your matches here, just looking at them, where there's no green square on the pink pressure curve, whatever that was, if it's not closer, that's not too good a match; is that right?

A. Well, I think the only ones that really aren't that close -- Where there are significant differences are the initial pressures, and typically, those are a little bit low. So I think there are some of those where we may have just seen an initial pressure that wasn't built up enough to represent true reservoir pressure.

Q. Yeah, there might be some others if you look closer.
A. But -- Yes, sir, to answer your question, where you have a high degree of variation between your actual pressure and your match pressure.
Q. Yeah, so that's what we're looking at, really, is the pressure rather than the rate?
A. That's correct, that's correct.
Q. And then to tame that, I guess you have a couple mechanisms, or properties that you change in the grid blocks, I guess. And I didn't see that -- I must have missed that, the initial porosity and the permeability distribution. Is that in here?
A. We did not present that, but that is here and available if we'd like to look at that.
Q. I'm just curious. What did you hone in on to obtain your rate?
A. Mr. Brannigan, when he did his net-pay calculations, also indicated porosity and gas saturation, so he had a ϕsg component for each well.
We then contoured that -- Mr. Brannigan contoured that just like the net-pay map, same criteria. That was input into the model, just like the net pay. So in each block we defined thickness, and then with the ϕsg value defined the amount of hydrocarbons in each block.

The permeabilities were determined from the buildup tests, the 1993 buildup tests, and they were scattered in nine wells throughout the study area, and we contoured that value, just like we did the net pay and the ϕsg, and then those values were input into the model.

So we input an initial permeability and an initial ϕsg and an initial net pay.

Q. Did you get a match on the initial run?

A. We have not justified that all, so that is -- As you calculate the permeability values, that's how you see them --

Q. Yeah.

A. -- that's how you see them.

Our -- as we mentioned, what we -- Now, to answer your question, on some of these pressure matches, where the 1993 buildup survey is a little bit high or a little bit low, that could be adjusted by going in and moving the permeability contour one way or the other, very slightly. But to me, the matches were close enough on our first attempt, just with the actual data, that we didn't need to change it very much.

What we found to be the controlling parameter in the match was the gas in place, and with the initial match -- the initial map was too big, we said, Hey, let's try the UMC map. It was a little bit too small. And then as we found some of the discrepancies between -- we calculate net pay and the way they had, it increased it up to 86 BCF, and this is what you see at that point.

COMMISSIONER WEISS: Okay, thank you.

THE WITNESS: Yes, sir.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Payne, on your final concluding -- I guess Tab 14, that remaining reserves for existing wells showing Sections 26 and 35 with and without that well --

A. Yes, sir.

Q. -- with the proposed well you show 4.9 BCF. Is that -- That recovery is proportional to the amount of net pay that you have in the wellbore, is it? Is that a function?

A. Well, that 4.9 BCF is the 3 BCF that we predict for the proposed well, plus the remaining 1.9 for the other two wells. So you can see that there is an effect on the Harris 8 and the Harris 4.

Q. I was thinking more in terms of with the isopach map, that --

A. It is a function --

Q. -- of net pay?

A. The initial rate certainly is a function of net pay, yes, sir.

Q. The initial and the ultimate recovery?
A. Yes, sir, it would be.
Q. Would you look at the, I guess, Exhibit Number 2 for a minute?
A. Yes.
Q. And if you -- Would you recommend to Mr. Read a location in Section 26, 1980 from the south and west lines, which looks like it would intersect that 40-foot contour, rather than maybe the 32-feet that might be recovered by the proposed location?
A. The only reason I would not recommend that location is because of its proximity to Well Number 8. You're getting into a lower-pressure area of the reservoir, and it -- The initial rate is a function of net pay, but that's not the only component.
If you get into a lower-pressure area that's already been -- I mean, the Number 8 well has already made about 5.5 BCF of gas. So if we got closer to that, you're in a lower-pressure area of the reservoir, and I think that would drop the initial rate. So --
Q. Could that be balanced by the increased pay?
A. Well, I wish I had the answer to that question. It would be conflicting effects. One makes it higher, one lower. I don't know what would be controlling in that situation.

CHAIRMAN LEMAY: That's the only question I had. Thank you.

Additional questions?

MR. KELLAHIN: Some redirect, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q. I have a sense, although you've said it several times, Mr. Payne, I have a sense that not everybody's straight on what you do with the maps. Let's go back to the maps.

A. Yes.

Q. You've planimetered the original Read and Stevens map from the Catanach hearing --

A. Yes, sir.

Q. -- and found that it was too big a map?

A. That's correct.

Q. The container was too large for the 86 BCF of gas in place that you were calculating, using your methods?

A. That's correct.

Q. So you rejected it?

A. Yes, sir.

Q. That map did not go into the simulation?

A. That's -- Yes.

Q. All right. You looked at the UMC map?

A. Yes.

Q. It was too small to fit?

A. That's correct.

Q. It was 80 BCF of gas in place, and it was your judgment it was 6 BCF short for the study area?

A. Yes.

Q. All right. So you had Mr. Brannigan generate Exhibit 2, which is computer-inputted with Exhibit 3, and that's the map that was used?

A. That's correct, that is the process we went through.

Q. And so when we compare -- If UMC puts in their isopach and we compare their isopach to your Exhibit Number 2, then we'll be able to see some points of difference, and you described some of those earlier?

A. Yes.

MR. KELLAHIN: All right, no further questions.

CHAIRMAN LEMAY: Thank you, the witness may be excused. Thank you very much.

THE WITNESS: Thank you.

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

CHAIRMAN LEMAY: Okay. Is Mr. Brannigan going to testify at all, the geologist?

MR. KELLAHIN: I hadn't anticipated to call him.

CHAIRMAN LEMAY: Okay.

MR. KELLAHIN: I think with giving you the isopach, that completes what Mr. Payne had done.

CHAIRMAN LEMAY: I see, okay. Did you move to -- anyone move to incorporate the previous record, or do you want that --

MR. KELLAHIN: No, I hadn't done so. I would --

MR. BRUCE: I would move to incorporate it.

CHAIRMAN LEMAY: Is that your wishes?

MR. KELLAHIN: I think this record will stand alone.

CHAIRMAN LEMAY: Sometimes you incorporate previous records.

MR. KELLAHIN: It's a real short transcript. I don't think it's a big deal to read it.

CHAIRMAN LEMAY: Okay. Fine, we'll incorporate it.

BRET C. JAMESON,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence for the record?

A. Yes, my name is Bret Carlton Jameson, J-a-m-e-s-o-n. I reside in Parker, Colorado.

Q. And who is your employer and what is your occupation?

A. Occupation is senior development engineer for UMC Petroleum Corporation.

Q. Have you previously testified before the full Commission?

A. No, sir.

Q. Would you please briefly discuss your educational and employment background?

A. Yes, I obtained a bachelor's of science in petroleum engineering from Texas Tech University in December, 1988, then worked for Exxon Corporation for several years and GLG Energy, who was taken over by General Atlantic, who was taken over by UMC Petroleum Corporation, and that's where I work presently.

Q. Does your area of responsibility at UMC include southeast New Mexico?

A. Yes, it does.

Q. And are you familiar with the engineering matters related to this Application?

A. Yes, I am.

Q. And did you testify on behalf of UMC at the Examiner hearing on this matter?

A. Yes, sir, I did.

MR. BRUCE: Mr. Examiner [*sic*], I would tender

Mr. Jameson as an expert petroleum engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Bruce) Mr. Jameson, first would you identify your Exhibit 1 for the Commission and discuss its contents?

A. Yes, sir, Exhibit 1 is the same net-sand map that we showed in the Examiner hearing. The only things different are the -- I blew up the area a little bit so we could see a little more clearly the area in question. And I show a legal area down in the southeast corner where the Harris Federal 4 could have been drilled, and where an offset -- a legal offset could be drilled, as I understand it.

Q. Okay.

A. The other thing I show on here is a purple or kind of magenta polygon that encompasses the two sections, labeled Section 26 and 35 and that was a -- That's a polygon used in calculation of gas in place that the computer does, as far as planimetering that area. That's just defining the area of the gas in place.

Q. Now, looking at what you say is the legal area, what does this show you in comparison with UMC's acreage?

A. Well, obviously we're both drilled on the same pattern, a northwest and a southeast well. We -- Our White

State Number 2 well obviously is drilled off the section boundary, substantially, 1980 foot.

It also shows that our -- from our interpretation, the White State 2 is a thinner well than their Harris Federal 8, and our White State 1 is a thicker well than Read and Stevens' Harris Federal 4.

Q. Could Read and Stevens drill a well at a standard location in the southeast quarter and get sand equivalent to your White State Number 1?

A. Yes, sir, they could, and in fact they could exceed it dramatically.

Q. Is the White State Number 1, your well, a good well?

A. Yes, it is. It's made over 3.5 BCF.

Q. And what is your estimate of ultimate recovery from that well?

A. For the White State 1, my estimated ultimate is over 5 BCF.

Q. Okay. Mr. Jameson, I've handed you what we've marked UMC Exhibit 1A. This is simply a copy of Exhibit 4, submitted by Read and Stevens at the Examiner hearing, is it not?

A. Yes, it is.

Q. Comparing this, your Exhibit 1A, Read and Stevens' old Exhibit 4, with their new net-pay map, Exhibit

2, are there any differences?

A. Yes, sir, there's substantial differences, and I might point out a couple of them.

The -- Primarily in our acreage, the White State Number 1 in the southeast quarter, the old Read and Stevens map, as I understand it, shows 18 foot of net pay. The new map shows, I believe, five foot of net pay. That's a substantial difference. I would think log calculations are better than that. It wouldn't change that significantly with a reservoir-simulation model.

Also the White State 2, previous map showed 22 foot; now it's 18. I think the interesting thing on both of those is that our net pay was reduced substantially, as I understand it from an engineering model. But that engineering model does not have an accurate pressure data for our section. It has 24-hour state-required shut-in pressures that were last taken in 1993.

What would be required to really determine what the pressure was in the sections, would be a long-term pressure buildup, like Read and Stevens had, or obtained in 1993 on their wells. And I might point out that that isn't something that we would do on a regular basis, but if it could make the point clearer, we could go get a buildup at, you know, a couple-thousand-dollar expense to us on our wells, and I think it would probably show a dramatically different pressure than the 24-hour shut in.

The other differences on this map -- I kind of got sidetracked there. In Section 23 to the north of the Read and Stevens section in question, the -- I believe it's the Harris Federal Number 6, was 22 foot of pay; now it is 36. The Harris Federal Number 9 was 16 foot; now it's 22. I haven't gone through every section on the two maps, but obviously there's dramatic change in the net thickness from the last --

Q. And the change for UMC is downward, and the change for Read and Stevens is the same or upwards?

A. That appears to be the case, yes, sir.

Q. And they attribute some zero net pay in the northwest quarter of your section too, don't they?

A. That is correct.

Q. Which they didn't previously do.

Is there -- Do you know of any new wells out there that would make this change?

A. No, sir, I do not.

Q. Okay.

A. I think another interesting point on that, in relation to that zero-foot line that we're talking about in the northwest quarter of 23, if you look at their old map, that was a 30-foot isopach, and now it's -- where that -- the new contour is, is a zero-foot. So that was dramatically changed, reduced.

Q. And they had some 40 feet of pay up there in their sections too, don't they?

A. Yes, sir.

Q. Would this dramatically effect the calculated gas in place?

A. It sure would. It would increase their gas in place significantly and reduce ours.

Q. Now, looking back to your Exhibit 1, is drainage in this reservoir, in your opinion, going to be radial?

A. No, I don't believe it is. It should be along the channel trend.

Q. Okay, more oblong?

A. Yes, sir.

Q. Let's move on to your Exhibit 2. Would you identify that for the Commission and discuss its contents?

A. Yes, Exhibit 2 is just a planimetered gas in place, based on the map that is Exhibit 1, our map. The properties, it appears, are pretty similar, as far as reservoir properties. I notice Read and Stevens used a -- Well, I'm getting ahead of myself, excuse me.

The first thing on the page is the area and gas in place that we calculate from our map for the two sections, and that is 1304 acres and 22.08 BCF. The properties and reservoir properties I used for that calculation, ϕh and area, are calculated by the computer, based on the map. Water saturation is the same, I believe, as Read and Stevens used. The formation volume factor is very similar; I believe theirs was about 219, somewhere in there. And the reservoir pressure is fairly similar; I believe theirs was 3500.

So from a reservoir-property standpoint, I believe we've got fairly comparable factors that we're using for the equation.

The next thing that I show are our predicted recoveries for the four wells, and estimated ultimate recoveries are 23.7 BCF, or 107 percent of gas in place. Our current cumulatives are 15.4, or approximately 70 percent of gas in place.

When I calculated this gas in place, obviously exceeding -- having the gas in place lower than the estimated ultimate recoveries isn't something you normally see. One of my options, I guess, would have been to go in and do some changes to the isopach map, to try to get that more reasonable. In other words, bump up my gas in place.

I didn't do that because I thought that this is more or less a computer-drawn map, it hasn't been tampered with significantly, that would alter the data that we have assigned to the individual wells.

Now, under the results, I point out a couple factors that could explain why my EUR is higher than my gas in place.

One is potentially that the existing wells are recovering gas beyond the boundaries of the two sections. That could be the case in -- from the north or the south, really in any direction. I cannot tell you at this point.

The other thing is that I may be too optimistic on my estimated ultimate recoveries for the wells, based on a decline-curve analysis. When we get to the decline-curve analysis, you'll see that there's -- Well, looking at Read and Stevens' decline-curve analysis, there was substantial interpretation in those extrapolations of production.

Either cause, I guess, points to the same conclusion in my mind: The gas in place is going to be adequately drained by the existing wells that are drilled.

Q. And based on this data, will Read and Stevens' proposed well recover new reserves?

A. No, sir.

Q. As a result, in your opinion, should the well be drilled?

A. No, sir.

Q. Now, you've already discussed pressures to a certain extent. Would you identify your Exhibit 3 and just briefly go over again I think what you've already said?

A. Yes, Exhibit 3 is, again, the 1992 shut-in pressures that were supplied to the State. They're 24-hour shut-in pressures. As I understand it, they're surface shut-in pressures, which also add the potential for error with any kind of a fluid level.

What they show, I just summarized on the first two pages, because -- on the first page, because it's kind of hard to pick the wells out on this small font. Their Harris 4 well showed 500 p.s.i., roughly. Their 8 was 1350. Our White 1 was 663, White 2 was 1013.

What that shows me is a couple things. The tighter wells or the wells that did not produce as much gas, the rates are lower, have a lower pressure. Obviously, you wouldn't rely on that pressure data very well, because what that says to me is that tighter wells are not given enough time to build up and show the correct reservoir pressure. And so permeability or producibility in the wells is a major factor in the reservoir pressure shown on these 24-hour shut-ins.

A very, very good well might build up to a relatively close or accurate reservoir pressure in 24 hours, but a very, very tight well, like their Harris 4 well, I don't believe that's an accurate representation of reservoir pressure.

Q. And again, what would be necessary to adequately determine the drainage concerns and the proper number of wells in this area?

A. You know, I believe -- Good pressure buildup data would be required. At the last -- At the Examiner's hearing I brought that point up several times and asked for any kind of extended bottomhole pressure data. None was brought forth. It didn't even seem like they had any.

So I was kind of surprised that they had -- Read and Stevens had buildup data from 1993 and, you know, I didn't hear about it in the last Examiner's hearing. That was news to me today when I saw their buildup pressures.

Q. If the Commission were to approve the proposed well, would you recommend a penalty on production?

A. Yes, I would, again, from my calculated gas-in-place numbers, I know the well's not necessary. But if the well was allowed to be drilled, it's going to be half the distance to the lease line that our White State 2 well is, and so therefore it's, I think, given an unfair advantage in that regard.

Q. Would you propose that the 50-percent penalty adopted by the Division be affirmed by the Commission?

A. Yes, I would.

Q. And you said that was based on the footage differences.

One other thing: What are the current producing rates of the -- combined, of the two wells in Section 26, versus the two wells in Section 35?

A. The two wells in our Section 35 are roughly a million a day, and the two wells in their Section 26 are roughly a million a day, so there is equality there. You know, no further wells being drilled appears to me to be a fair situation from here on forward.

Q. And I think you heard Mr. Payne say that they would anticipate their new well coming in at 1.3 million or 1.4 million per day?

A. Yes, sir, if that were true, obviously there would be a large inequity between the two sections.

Q. So if the penalty is too small, would that adversely affect UMC's correlative rights?

A. Yes, it would.

Q. And would this disparity in producing rates -- say if they got a million -- If they had two million a day or two-million-plus a day, versus your one million a day, would that disparity in producing rates give Read and Stevens a competitive advantage?

A. Yes, it would.

Q. And would this be aggravated by the oblong drainage pattern that you mentioned because of the shape of the reservoir?

A. Yes, I believe it would.

Q. Let's -- I think you've got Mr. Payne's Exhibit 1 there in front of you.

A. Yes.

Q. I think there's a couple of things we want to discuss on that. I believe it was -- I don't have it in front of me, Mr. Jameson, but I think it was Tab 10, there were some decline curves or whatever on there. Could you comment about your wells and the Read and Stevens wells, and could you refer to the well names for the Commission?

A. Yes. One of the things I'd like to point out here, I guess, is, there seems to be a fairly large drop when you look behind Tab 10, on the decline curve or reservoir simulation history match of the Harris Federal Number 8.

If you look at a time period between approximately 1990 and -- well, to the current time basically, you have no effective decline in that well. It's making, I believe, over 30,000 a month. And as I can see, there's not a real significant decline over that time period.

In the model, it shows a substantial drop, starting when the simulation comes into effect, down to 20,000 per month, and goes on a fairly steep decline. In my opinion, that's not a very accurate history match and not a very accurate interpretation of future production rates.

Q. Are there any other wells that you see that in that package?

A. Yes, if we -- Although it's not as important because the well is not as good, if you flip back to the Harris Federal 4, which is the preceding page, it shows a similar situation. You have a fairly established decline, which if you drew a line from approximately 1990 to present, through the data points, you would get a pretty established decline, which is significantly above their predicted rates from the simulation model.

So I don't think we've got a very accurate interpretation here of what's happening -- what's going to happen in the future. If you flip to the White State Number 1 --

Q. Do the two wells you just mentioned -- If you drew a decline curve, would it show a greater ultimate recovery for those wells than has been testified to by Mr. Payne?

A. Yes. Yes, sir, I believe it would.

Q. Okay. Move on to the UMC wells.

A. The UMC wells, the -- I guess it's the third page from the very back of that Tab 10. Again, you've got a fairly established decline for the White State Number 1. And if you drew that line, it's dramatically different from the Read and Stevens interpretation. It also shows, if you drew that line, that they're attributing a lot more reserves to the White State 1.

Q. Than what you attributed?

A. Than I would.

The next page is the White State Number 2. It did a pretty good job of modeling the production there. The only thing that I would question, I guess, is, as you look towards the data points in around 2000 to 2005, there's a substantial flattening of that pre-established exponential decline rate. They take it hyperbolic for a ways, and that has the effect, obviously, of also increasing the reserves substantially on that well.

Q. Do you think your calculations, your decline-curve analysis and calculation of the recoveries of these four wells is more accurate than those exhibited by Read and Stevens today?

A. Yes, sir, I do.

The other thing I'd like to point out on these, if we look at their pressures, that they show in the 1993 time frame from bottomhole pressures, bottomhole pressure data --

Q. You're still looking at these decline curves?

A. Yes, I'm sorry. If we flip back to the Harris Federal 8, we show that it had roughly a 1500 p.s.i. bottomhole pressure. On the magenta line there's a little green dot that I think is the actual pressure buildup data point. So they have roughly 1500 p.s.i. in their well from that bottomhole pressure data.

If we flip to our wells, looking at that same time frame, the White State Number 2 appears to show approximately 1200 p.s.i. bottomhole pressure. As I understand it, that's based solely on the 24-hour shut-in data from the state. There's been no pressure buildup data done on our leases. So that is a substantially reduced pressure.

The White State Number 1 is even lower, even though it's not as good a well. They show a pressure in the 1993 time frame of approximately 1000 pounds. So we're comparing their pressures of 1500 versus ours of 1000 to 1200.

And if we had done bottomhole pressure data, extended bottomhole pressure data in 1993, like their wells, I guess I would question what that pressure would have been. I don't think it would have been what is shown on the State forms 24-hour shut-in. I think it would have been higher than that. I think their pressure they're using for our lease is too low. And without pressure buildup data, there's really no way for either side to substantiate it.

But I just find it interesting that it's so much lower than their Harris Federal 8 well, even though recoveries are fairly similar for the individual wells.

Q. And what is the net effect of this pressure difference? Is it reflected adversely upon UMC's wells in these decline curves?

A. Yes, what that does, obviously, is, it -- If they're adjusting their gas in place for our lease, based on that, it dramatically reduces our gas in place.

I assume they had to plug in a pressure point, into their reservoir simulation, and if they had put in a substantially lower than actual pressure point into our wells, that would hurt our lease's remaining reserves.

Q. Now, I think you said -- To this point, I believe, Section 35, your section, has produced more gas than Read and Stevens; is that correct?

A. Yes, it has.

Q. Through whatever, luck, better geology, who knows?

A. That's right. We've produced, from my data, March of 1996, we've produced 9.2 BCF, and Read and Stevens have produced 6.2 BCF. Whether it's luck or better geology or better permeability in our section, our wells have done better than their wells.

That is going to be -- There are going to be inequities like that up and down the trend, basically any field you look at. Somebody's going to drill into the pay better than somebody else. And through completion practices or placement of the wells or whatever, they are going to produce more.

Q. And if the new well is allowed to be drilled, would that upset the equilibrium you talked about in producing rates between the two sections?

A. Yes, sir, I believe it would.

Q. Were Exhibits 1 through 3 prepared by you or under your direction?

A. Yes, they were.

Q. And Exhibit 1A is simply a copy of the prior exhibit, hearing?

A. That is correct. It's been blown up a little so that it's a little clearer, but it's the same -- same map.

Q. No, I mean the Exhibit 1A is --

A. Oh, I'm sorry.

Q. -- Read and Stevens' previous exhibit?

A. Yes.

Q. In your opinion, is the denial of Read and Stevens' Application in the interests of conservation and the prevention of waste?

A. Yes, sir, I believe it is.

MR. BRUCE: Mr. Chairman, I move the admission of UMC Exhibits 1, 1A, 2 and 3.

CHAIRMAN LEMAY: Without objection, UMC exhibits will be admitted into the record.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Jameson, if you'll look with me at Exhibit 2, on your analysis at the top of the page you've got a gas in place for both Sections 26 and 35. Can you tell me what the gas in place is for Section 26?

A. Yes, sir, I can. The gas in places I calculated for -- Was it 26?

Q. 26, yes, sir.

A. -- was 11.8 BCF.

Q. And for 35 -- ?

A. -- was 10.2 BCF.

Q. 10.2 BCF for 35?

A. Yes, sir.

Q. There are some calculations here that show how you went about getting your gas in place volumetrically. It says the ϕh and area were calculated by computer map. Can you give me those values for each of the sections that were used for the calculation? What porosity value was used for Section 26?

A. Yes, sir, the value was 13-percent porosity. And the net pay, you know, is a computer planimetering of the net-sand map that I show there.

Q. Off of Exhibit 1?

A. Yes, sir.

Q. And do you use 13 percent for both sections?

A. Yes, sir.

Q. You talked about some of Mr. Payne's decline curves and were suggesting that you must have plotted those declines to get an EUR that was different. Your summary sheet shows for the Harris Federal 8 that you're estimating, I assume, off of the decline curve, 9.6 BCF. Mr. Payne shows 8 BCF, if I'm not mistaken. Do you have -- You didn't introduce any decline curves. Do you have your decline curves?

A. Yes, sir, I do.

Q. Did you prepare a decline curve for the Federal 8?

A. Yes, sir.

Q. All right, let me see your map. Let me see what you did. Based upon your decline curve, then, you get for the four wells 23.7 BCF, right?

A. Yes, sir.

Q. And you've got 1.7 BCF more than you have gas in place?

A. That is correct.

Q. Did you go back to your geologist and attempt to re-examine the isopach to see if the isopach was too small?

A. No, sir, I didn't. The geologist picked the picks for the individual wells. Those are based scientifically on log-analysis practice. I guess I wouldn't respect his opinion if he changed his picks just because I told him that the gas in place didn't work out.

Q. Well --

A. When I explained his results in the bottom of the page, there could be several factors, one being that my EURs from decline curve were too optimistic, the other being that the two sections are not a contained vessel. There may be pressure coming -- I mean reserves coming onto the leases outside the boundaries of my magenta polygon, volumetric polygon.

Q. Well, let's just look at 35. 35 gas in place volumetrically, you show 10.2. If you take the White State 2 and 1, you're going to -- by your decline curve, you're going to get 13.5. You've got a -- more than 3 BCF gas more produced than you have gas in place, right?

A. Yes, sir.

Q. It's going to come from somewhere, isn't it?

A. It's going to come from somewhere, or my estimated ultimates are optimistic. Those are the two factors that I point out at the bottom.

Q. All right. Either your decline-curve projections are wrong, they're too high; either your map's too small, it needs to be bigger; or in fact you're going to get it from somebody else?

A. That's correct.

Q. All right, let's look at the somebody else. Have you made any kind of investigation to see if one of the probabilities is that you're going to take the gas off of the southwest quarter of Section 26?

A. Yes, sir, the -- as I pointed out a few minutes ago, our wells are placed better in the channel system than the Section 26 wells.

Q. Okay.

A. In their early production history, we obviously cum'd -- had a higher cum on our lease than the Section 26 lease. That was based probably -- well, several reasons. Either we drilled our wells geologically on trend better, we were lucky, we had better permeability, whatever the reason. But if you look from this point forward, the remaining gas on the two sections is equal.

Q. All right. Let's look at this. Let's assume your map's right, let's assume your decline curve's right, and you got an extra 3 BCF that's coming from someplace, okay? Have you attempted to quantify where that someplace would be?

A. Without a pressure buildup in all the wells around us and doing an intensive simulation, I think that would be pretty difficult to answer. You've got a complex situation out here. You do not have wells that have consistent permeability. We see that because we see some thin wells that have produced a lot of gas, we've seen some thin wells that haven't produced much gas.

If you look in Section 34, right beside our section there's a well, the Toles Federal Number 1 on my map, that has 12 foot of pay, and yet it's cum'd 3.7 BCF. Obviously, that's --

Q. Look at your map. In the southeast quarter of Section 27 it looks like the reservoir is pretty thin there. This 3 BCF of gas is not likely to come off of 27, is it?

A. I'm sorry, southeast quarter of 27?

Q. Yeah, look at the fairway.

A. Right, correct.

Q. Look at the fairway. You've got a fairway, you've got a channel running in the west half of 26, the west half of 35. It looks like all the White State 2 and the Harris 8 are going to be the two best wells that are going to be competing with each other, right?

A. Yeah, along with the Harris 9, I guess, up in 23, it's a pretty similar well, as far as recoveries to date.

Q. And your White State 2 is only -- what? 1980 feet from the common line between the two sections, right?

A. Yes, sir.

Q. And the Harris Federal 8 is what? Another 2000 feet farther away from the common line?

A. That is correct.

Q. All right. When you look at the pressure differential -- You've got some pressure data. We know from your section, by your own testimony, that you've got about 1000 pounds and that the Harris --

A. No, sir, I wouldn't say that. The 24-hour shut-ins I don't think are an accurate interpretation of what the reservoir pressure is.

Q. Well, let's look at the relative pressures though. Back in May you were testifying that the 1992 24-hour shut-ins on the Federal 8 and on the White State 2, the Federal 8 has got thirteen-five, the White State 2 has got 1000. They may be off, but at least they're relative, are they not?

A. They are relative, and I would point out that their cumulatives are relative, so their permeabilities are probably somewhat relative.

Q. You have a pressure advantage in terms of a pressure sink to the White State 2, right?

A. No, sir, I couldn't say that without getting a buildup. I mean, 24-hour shut-ins is not an accurate interpretation.

Relative -- When I say relative, the Harris Federal 8 and the White State 2 are both -- One of them is 1000, one of them is 1300. They're probably somewhat similar -- Well, they're similar in cumulative production to date. They're probably somewhat similar in permeability or producibility, let me back up.

Q. You made that comment back in May when you talked about the inadequate pressure data in Section 35. You're talking about it again today.

A. Yeah, it's inadequate.

Q. Why didn't you go get something after the May, 1996, hearing? You could have gotten a bottomhole pressure test?

A. Well, to be perfectly honest, sir, a penalty was imposed, and I didn't see that there was a need to do that.

The other thing, I guess, to point out here is, we're not going to -- trying to go drill a well, and should we really go out and spend $2000 or $3000 to prove a point that we believe has already been ruled on and substantiated?

Q. Mr. Jameson, when did you get your degree?

A. In December of 1988.

Q. Since your degree have you done reservoir simulation?

A. Pretty minor reservoir simulation. Nothing --

Q. Nothing like what Mr. Payne has performed here?

A. No, sir, I'm a town sheriff up against a gunslinger there.

Q. Did you understand and appreciate the fact that the bottomhole pressure data that Mr. Payne was matching was generated based upon tests that he was satisfied with, that were nine of the 22 wells back in 1993? You heard that, right?

A. I'm sorry, could you say that again?

Q. Yes, sir. He -- Part of his presentation showed an elaborate investigation where he's matching the bottomhole pressure of nine of the 22 wells in the study area, right?

A. That is correct, and I might point out from that, a least-squares fit is a good fit. I mean, it's a good method of doing it.

But if you look at Tab 4, the first page, showing bottomhole pressure versus cumulative production, there is a huge range in pressures. And as you draw that line through those points, you get a substantially different gas in place. The bottom point gives you 66 BCF, the top point gives you 93 BCF of recoverable reserves. Least squares is good but I wouldn't hang my hat on it when you've got that kind of range.

Q. Yeah, but you know that the upper limit is wrong and the lower limit is wrong, and so why don't you just --

A. How do I know that?

Q. Because you've got other pressure points to try to match, and so why do you not use a statistically valid methodology, which is the least-square method?

A. I'm not saying it's not a valid method, don't get me wrong. What I'm saying is, there's a wide range in pressures in the model reservoir that we simulated, and to hang your hat on the pressure right in the middle, I think, is invalid.

You may have -- I don't know which wells -- what the thickness, permeability, other properties were of the wells that the pressure data was obtained on, but a lot more comes into play than just taking the middle one and extrapolating a line. I mean, you've got a huge range there, 66 BCF to 93 BCF of recoverable reserves. That's, in my opinion, too dramatic of a range to really feel comfortable with.

Q. Did you understand what he's trying to do?

A. Yes, sir.

Q. That he was trying to take the least-square line and validate that by looking at all the data points that he had, and if you take the lower range or the upper range, you exclude a number of the data points?

A. As I understand it, sir, that is correct. But the map -- As I understood the previous testimony, the map net pay was dramatically changed as a result of the model, and how the model -- if the model conflicted with the map, the map was changed. And in my opinion, the model is not accurate enough to be changing the log analysis of the wells within the area. And that was my point.

Q. All right. Let's go back, because I think either I misunderstood or you did. It was my understanding that Mr. Payne was not even into reservoir simulation at this point.

By decline-curve analysis, he had come up with a number for gas in place, and he had planimetered your map, and he found by planimeter within his study area, he had 8 BCF of gas in place. He decided it was too small because it was not fitting his data, and he asked Mr. Brannigan to look, excluding the Read and Stevens map, is to look at this area again and construct a new map, which is the Read and Stevens Exhibit 2. And that map for our purposes of study contains 86 BCF of gas in place.

A. How much, if I -- I guess I didn't see a question there.

Q. Well, the question is, are you still contending that Mr. Payne was trying to match or adjust the isopach based upon the simulation? Because that's not what he did.

A. Maybe I misunderstood his previous testimony. When I look at Exhibit 2, I see a dramatic change in the net pays on our wells. I mean, the White State 1 went from 18 feet to 5 feet. The White State 2 went from 22 foot to 18 feet. And, you know, I've looked at the logs out here. I don't know how you could possibly pick something 18 foot one time and 5 foot the next.

Q. Let me go back to your --

A. That was my whole point. I --

Q. All right. Let's go back to something that you've worked on. We've got original gas in place in Section 26 and 35. What is the remaining recoverable gas now? What's that number?

A. Remaining reserves?

Q. No, sir, remaining recoverable. I want to know for now --

A. Yeah, remaining recoverable reserves for the two sections, is that -- I'm sorry, is that what you asked?

Q. All right, let's start back one step. We had original gas in place, and you've got 10.2 for 35, okay? What is the current gas in place?

A. I didn't simulate it, so I couldn't really give you that number. What I can give you is what I estimate as the estimated remaining reserves based on decline-curve

analysis. With -- You know, without a simulation, I --
Q. Well, forget simulation. Give me what you think is gas in place now. You're produced a bunch. We know the original by your calculation. What's left now?
A. From decline-curve analysis, what I have is Section 26 has 4 BCF and Section 35 has 4.3 BCF.
Q. Yeah, you're giving me a reserve number.
A. Yes, sir. Like I said, I don't have a simulation, and I don't know what the pressures are in the two blocks, the two sections, so I couldn't give you a remaining gas in place, per se.
Q. All right. If you can't give me what your opinion is of the original gas in place --
A. Remaining?
Q. Yeah, the current gas in place at this point. -- how are we ever going to figure out what is UMC's relative share of that gas in place now, versus Read and Stevens, except to do it like Mr. Payne did it?
A. I compliment Mr. Payne on his work. He's very diligent. He -- I don't want to get the wrong impression here. He incorporated all the data he had. That is the only way -- I think I stated in my last testimony to the Examiners, that is the only way to really see what's going on out here.
But because I don't -- nobody has pressure in

Section 35 and, for that matter, nobody has current pressures in Section 26, I don't think we can put our finger on what is the gas in place for either section.

And again, you know, I just -- I see some problems with net-pay picks, and I see some problems with the range of the P/Z calculated gas in place.

But don't get me wrong, I'm not saying Mr. Payne didn't do a good job. He just didn't have all the data he needed, and there's a fairly significant change -- or a range in the calculated gas in place from the P/Z, and I think our map is an accurate interpretation of the channel system.

Q. Let me make sure I'm clear. You do not know and can neither confirm or refute Mr. Payne's calculation of the current gas in place in 26 or 35?

A. I think based on the map, I can refute what he's giving Section 35, just because it's a substantially different net-sand map than our net-sand map. But without, you know, pressure data in our section, you really can't determine, I don't believe, the current gas in place --

Q. All right.

A. -- because your 24-hour shut-ins aren't accurate enough.

Q. The answer to my question, then, is that you do not know?

A. I may have talked too long. I can't remember what the question was, I'm sorry.

Q. You do not have an opinion as to the current gas in place for 35 and 26?

A. No, sir, I don't.

MR. KELLAHIN: No further questions.

CHAIRMAN LEMAY: Thank you.

Commissioner Bailey?

COMMISSIONER BAILEY: I don't have any questions.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. What algorithm did you use to draw this map?

A. It's an adaptive-fitting algorithm, and the -- we use geographic system, if you're familiar with it, and it's called adaptive fitting.

Q. If you used another algorithm, what would you have gotten? My question is, does the machine draw different maps like people draw different maps?

A. Yeah, there are certainly several different algorithms you can use: minimum curvature, least square. There's many. For a channel system, we've found that adaptive fitting provides the best map. It shows a channel system very strongly, and we think it's the most accurate.

Q. If you had seen this simulation work before today, say a month ago or last week or something, would you have run some pressure-buildup tests? Would you have done anything different?

A. I probably would have thought about it pretty hard. Obviously, we don't like to go spend $2000 or $3000 unless we have to. But I guess, looking at the package, you know, it's a very complete -- There's a lot of data there, and it looks great.

I probably would have done it, just because I wouldn't want to come in here unarmed.

Q. Yeah. And then you did acknowledge that your EURs are larger than the gas in place. So there's some agreement there; everybody saw that.

A. Yes, sir.

Q. And do you think that an attempt to honor the dynamic data improves the reservoir description? Or do you think that, you know, just a contour map with adaptive fitting, drawn by that technique, is of significance -- is enough?

A. I think you've got to certainly honor the log analysis. And when you start letting the reservoir simulation drive your end result, I think you do get in trouble from that standpoint.

As you probably know, a simulation is only as good as the data you put in it, and if you don't have any data, it's very tough. Any good pressure data or permeability data.

COMMISSIONER WEISS: Those are my only comments, thank you -- questions.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Jameson, a couple things, I guess. I'm looking first at your Exhibit Number 1. Is it possible that some of the increased production out of Section 35 comes from the fact you were maybe a year earlier in the reservoir? It looks like you've completed wells in 1980, 1981 in Section 26, 1981, 1982. Is that a factor too?

A. Yes, sir, certainly that could -- we would have gotten a jump -- a headstart on them.

Q. The other thing, I'll just talk about the channel. I finally got out Exhibit Number 1 of the previous case. We're trying to describe something without seeing it, without even having a type log. This channel is being treated in here like it's homogeneous, it's one definable -- Can we get that exhibit out for a minute, Exhibit 1? Is that something can talk from?

MR. KELLAHIN: Yes, sir.

Q. (By Chairman LeMay) Read and Stevens Exhibit 1.

I assume this is about as good a portrayal of some of the log characteristics of the pay as anything we've got in the...

A. Yes, sir, I believe so.

Q. Well, we see the one channel. We also see, I see, some other sands that I guess are not part of the channel. They're not connected, anyways, as -- Look at B-B first. B, I think, would be the -- the Read and Stevens Number 8 Harris; is that right?

A. Yes, sir.

Q. Okay. You've got the channel, and you notice you've got some sand perforated below the channel. If that's not connected to the channel, would that be contributing reserves that wouldn't be...

A. I'm not sure if it's perforated or not, sir. We don't show perforations, but --

Q. The exhibit shows it to be perforated. I'm not showing -- not the bottom one.

A. Oh, okay.

Q. I'm -- just the one -- that isolated stringer about --

A. Yes.

Q. -- 8 feet below the main channel.

A. Yes.

Q. I guess what we're saying is, in trying to characterize this reservoir, are we looking at one sand buildup, the Harris buildup, as being this one body, and there are other sands that come and go in the Atoka, that can contribute to reserves that aren't being isopached?

A. Certainly, that -- Yeah, that could be the case. I mean, there are stringers. There's a Morrow B sand out here that we've identified further to the east that's real prevalent. That may be a stringer of it, actually. I'm --

Q. Well, A' has that also, it has something down pretty close to the -- Of course, we're taking a well that hasn't made much gas. That looks like the -- Is that the Harris Federal 4? And you have a lower perforated sand interval there that doesn't seem to correlate with the main pay.

A. Right.

Q. Have you isopached that too, or did you leave that out?

A. That would have been left out in our net sand map because that's, I believe, the Morrow B sand.

Q. Okay.

A. Mr. Brannigan might be able to -- I shouldn't speak of their cross-section, but of our net sand. We would have just modeled the upper -- what we call A1, A2.

Q. Which on this cross-section would be that -- called main pay Atoka channel sand?

A. That's correct.

Q. Okay. In trying to come to grips with the disparity here, is it your testimony that the relative share of the remaining gas in place is not definable?

A. Yes, sir, I cannot define it without current pressure data on -- I guess the four wells in question is probably the way I would do it, get a buildup on each of the four wells that it --

COMMISSIONER WEISS: Can't you just subtract how much has been produced from the gas in place? Doesn't that tell you what's left?

THE WITNESS: Yeah, you could do that. But what you're -- Obviously, you would like another data point there to nail it down. I mean, if you had a current reservoir pressure on the wells, you could much more accurately determine that.

COMMISSIONER WEISS: You could produce it -- You mean you could more accurately measure --

THE WITNESS: Yes, sir.

COMMISSIONER WEISS: -- what's been produced to date?

THE WITNESS: No, sir, you would know exactly what the reservoir pressure was currently. And I guess in my way of thinking, I think of material balance and the -- Well, I haven't done that analysis, I guess, to be honest, and if initial gas in place is 22 BCF and we've recovered to date from the two sections 15 BCF, you could figure a linear relationship there and come up with a reservoir pressure to date, you know, right now, what is the average reservoir pressure?

But from a remaining-reserves standpoint, I guess I show 22 BCF gas in place, cumulative of 15. So looking at it that way, you would have 7 BCF remaining. I guess I missed that.

Q. (By Chairman LeMay) Let me end up with a final question. If you were Charlie Read and you owned Section 26, would you drill another well in it? And if you did, where would you drill it?

A. If I was Read and Stevens and -- I would not drill another well because my gas-in-place model shows that you're going to recover everything that's there with the existing wells.

One of the things I guess that I question is their rate. If the reservoir pressure -- Well, if there's 7 BCF remaining, I don't know what the reservoir pressure would be but it's going to be fairly low, and the rate on that well is probably going to be pretty low. I guess I'm not near as optimistic as they are, as to the producing rate of their proposed well, in my mind. I'm not sure it would be economic from that standpoint.

And obviously from my analysis, it's not necessary from a drainage standpoint. We both have 4 BCF remaining in our respective sections from decline-curve analysis.

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

Anything else of the witness? If not, you may be excused. Thank you very much, Mr. Jameson.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: Are you all through?

MR. KELLAHIN: I am, Mr. Chairman.

CHAIRMAN LEMAY: Both sides?

MR. BRUCE: I am.

CHAIRMAN LEMAY: Do you want to wind it up?

MR. KELLAHIN: Yes, sir.

CHAIRMAN LEMAY: Do the fellow Commissioners have any questions that might be asked any of the witnesses?

Okay, let's wind it up. Do you want to go first, or how do you --

MR. BRUCE: According to Mr. Carr's rules, I go first, so...

CHAIRMAN LEMAY: He who's last is first?

MR. BRUCE: Mr. Chairman, members of the Commission, I think it's -- the situation is pretty clear. We have two sections of land, basically, we're fighting over today. Each section has wells in the northwest quarter and the southeast quarter of the sections, and each section is producing about a million cubic feet of gas per day.

It's UMC's assertion that competition between the two sections is equal as of today, but Read and Stevens wants to drill a new well which will give it a producing rate of 2.2, 2.4 million per day from its section, versus UMC's 1 million a day. We don't think this well should be drilled.

First, as Mr. Jameson testified, it's unnecessary to drain the reserves that are remaining on the two sections. Therefore, we think drilling the well is an economic waste.

Second, Read and Stevens -- Although they didn't put on their geology, Read and Stevens' own geology shows they can drill a second well in the southeast quarter of Section 26 at an orthodox location and hit the same amount of sand. This tells me either, one, they don't believe their own geology, or really the aim of this well is to give Read and Stevens an unfair competitive advantage over UMC.

Read and Stevens says, But UMC will ultimately produce more gas than us. Well, sometimes that happens, whether, as Mr. Jameson said, by skill or luck. The UMC's were drilled before the Read and Stevens wells. I think if you look at the early production data, they were producing 1, 2, maybe 3 million cubic feet a day for a year or two in advance of the Read and Stevens well. That happens. UMC wasn't at fault for that. What they did was perfectly normal.

In the previous hearing, Read and Stevens testified that the average recovery per well in the Buffalo Valley-Penn Pool is about 2.5 BCF per well. Its two wells in Section 26 are going to produce an average of 5 BCF per well. We think it can hardly claim it's at a competitive disadvantage.

Now, Mr. Kellahin got up here in the beginning and said, But Mr. Chairman, there's new data that Examiner Catanach didn't have in front of him.

There is no new data. Read and Stevens just didn't like the result they got the last go-around; they hired a new engineer to re-manipulate the prior data so it looked more favorable to them. In other words, their story has changed.

When you're going through this, if you would compare Tab 7 of Mr. Payne's Exhibit 1, versus Read and Stevens' Exhibit 3 from the Examiner hearing, if you'll look at that map, back in the first hearing Read and Stevens said, We are going to ultimately recover 10 BCF, and from today we're going to recover 4 BCF. Not bad. And by the same token, UMC was going to ultimately recover 11 BCF, almost the same amount, and from today forward recover another 2 BCF. Sounds like things are pretty fair.

Today they come in and say, Huh-uh, we're only going to recover 8.7 BCF, and the extra recovery from our section is only going to be 2.5 BCF. But UMC, all of a sudden, instead of recovering 2 BCF more, is going to recover 5 BCF more, and its ultimate recovery is going to be 14.2 BCF versus the 11 from a couple of months ago. We're talking 50-percent changes in the numbers here.

We think the changes in the story are just incredible, not only on the engineering but on the geology, and Mr. Jameson had already pointed those out. The changes in the net-pay maps again are not warranted by any new data; it's just an attempt to manipulate the data to make them look poorer than UMC. And as I said, we believe that adding the new well will contribute to an unfair competitive advantage to UMC.

If the proposed well is drilled, they'll have a 100-percent higher producing rate than UMC, and that advantage will be aggravated by the north-south preferential drainage in this reservoir. We don't think that should be permitted.

Now, at the Examiner hearing, UMC urged a 33-percent allowable or a two-thirds penalty, and that was based not only on footage differences but on undrained acreage, which Read and Stevens' prior engineer testified about.

Their first engineer said that 94, 95 acres in the south half was going to be undrained by the wells as now located and that they needed that well to drain those 94 acres. We just simply divided 94 by 320 and came out to about a one-third allowable. The Division set a penalty, instead, of 50 percent of the well's ability to produce.

If Read and Stevens is permitted to drill this well, UMC accepts that 50-percent penalty. We think it will allow them to drill the well and still produce at a fair rate, and it will also minimize any adverse effect to UMC.

And as a result, we would request the Division's order to be affirmed.

Thanks.

CHAIRMAN LEMAY: Thank you, Mr. Bruce.

Mr. Kellahin?

MR. KELLAHIN: Members of the Commission, I have handed you a portion of the Oil and Gas Act, so that we can read what we're required to do today.

The statute requires in subparagraph A.8. that we do this, that insofar as can be practicably determined -- that's -- I've always had trouble with that word -- and so far as can be practicably obtained without waste, substantially in proportion, that quantity of recoverable oil or gas or both under the property bears to the total recoverable oil or gas or both from the pool, will represent each party's equitable and just share. That's the correlative-rights definition that we talk about all the time.

The only evidence before you is Mr. Payne's evidence as to what is the current gas in place. We're not talking about balancing the ledger because UMC had their wells in the pool earlier. That's not the point. What we're looking at is the relative share of current gas in place between 26 and 35. It ignores the fact that they're substantially ahead in withdrawals. You don't penalize them for being there early. You do look at the relationship of what they have now in terms of what they get to take out of the remaining gas in place.

Mr. Payne's last display summarizes it for you. He is the only engineer that has told you, based upon the analysis, the current recoverable gas in place is 8.4 BCF.

Without the protection well, the calculation shows that of the 8.4 BCF, Read and Stevens is entitled to 5, UMC is entitled to 3.4. And without the protection well, then, UMC gets to recover an additional 3 BCF of gas.

So what is the relationship? You simply take the 5 BCF into the 8.4, and instead of losing gas reserves, Read and Stevens should have 59 percent of the remaining gas.

Mr. Jameson did not know and he had not calculated -- Despite the fact that we've been fussing over this since May, he has not chosen to take any pressure data. They have not chosen to ask me for any of our data. They have not chosen to share in our simulation. They have not chosen to do anything but to decide that they don't like it.

Mr. Bruce talks about drainage. In his closing statement he must have said it two or three times, drainage Where is their drainage calculation? Where have they attempted to quantify the magnitude of what occurs if the Federal 11 is drilled? They have simply not done anything since the last hearing except give you a gas-in-place calculation.

No engineer at the Examiner hearing gave Examiner Catanach a gas-in-place calculation. The man had no place to start with the correlative rights statutory obligation to develop correlative share. All Examiner Catanach had was a geologic interpretation that had not been validated by the reservoir engineer, and he had some decline-curve-analysis conclusions presented by both sides, and neither side gave him decline curves.

And from that they did those wonderful little bubble maps. Aren't those maps fabulous? They presumed radial perfect circles and what they thought was going to be drainage areas. And they said the southwest quarter is not going to be drained to some extent.

Well, what we have done is apologized to you for not bringing Mr. Catanach a reservoir study. And we went outside of the company and hired Mr. Payne to do that work. Mr. Jameson compliments Mr. Payne. He said, If I had the time and the talent and the money, that's the kind of work I'd like to do and would have presented to you. It's the work that you have before you.

I'm delighted that you've incorporated the Examiner record. It's only 54 pages; you can read it in 30 minutes. And I will invite you to share the predicament and the dilemma Mr. Catanach had when he tried to grapple with this problem. You can scan through there, and the depth and the breadth and of the engineering talent that was presented absolutely escapes me, because in less than ten minutes both of those men are on and off.

If you want to come back to that, let's look at it. That's where Mr. Payne went. He went back to those maps. He says, I have planimetered both of those maps. The first Read and Stevens map is too big. I reject it. I've looked at the UMC map. It's too small, it doesn't fit. In fact, it even doesn't fit Mr. Jameson today. It doesn't fit. He presents it, admits it doesn't fit.

What did he do that -- he should have done that he didn't is to figure out why, among the things he was shopping through, it doesn't fit. All we know is, it doesn't. Either his container is too small, his decline-curve projections are too high, or he may be draining 3 BCF off of his tract that he's not entitled to recover. And that sort of is what Mr. Payne is telling us, is, they're going to get a bunch of gas, more than they're entitled to get.

Look at their map. You want to do geology, let's use their map. They complain and say that we ought to be in the southeast quarter of 26, but look at what they gave us for a standard location. There's not a place within the standard location in the southeast quarter that you're going to achieve a net-pay thickness in excess of the 20 feet.

And look at the marvelous southwest quarter. Isn't that wonderful? And look at the distance between the two wells to the common boundary. The UMC well is only 1980 feet away from the common boundary, and look where Charlie Read has got to compete if he can't drill another well. He's 2400 feet away.

How in the world is he ever going to do it? He can't do it. They already have a pressure differential. They enjoy 350 pounds' pressure differential as we speak.

He's got to protect himself, he needs a protection well, and he does so by putting that well in the southwest quarter.

I am sympathetic and appreciative of Commissioner Bailey when she says, I recognize your concern in the southwest quarter. Then what about the oddity that we have a common source of supply and two different rules to play by? It invites attention, and as soon as we can get beyond this crisis we're going to look at these rules. I think it's a serious problem to let a reservoir be managed, particularly when one is prorated and the immediate offset isn't. We've got a problem we need to fix. Don't let that problem distract you from paying attention to this one.

If you'll look at the Examiner exhibits and what Mr. Jameson told us today, there's something else about his map. He says this map is based upon a 13-percent porosity cutoff.

If you'll look at the transcript and look at the exhibits presented back in May, they were using 8-percent porosity cutoff. A big difference.

And if it was a problem for them, they should have fixed it now, but he tells us he's got a discrepancy in the maps, and maybe that will explain something.

I don't know how else to do this, except to do it as we propose, to have each side have a reasonable chance to determine what is the current gas in place, and then apportion it appropriately as required by the statute.

We've asked Mr. Payne to do that, he's accomplished it. It required him to tell us that the map we had was too big, the map they had was too small. And he and Mr. Brannigan have presented the map, and we've talked about it, we've looked at it. It's Exhibit Number 2.

He has matched pressure, he has looked at bottomhole pressure data from 22 of the wells. They have nice data on nine of them from 1993. Commissioner Weiss knows modeling better than I will ever expect to know it. And I will invite him to use his expertise and critique Mr. Payne's work, and if there's a flaw, tell us.

But if you agree with us, we would like the well. We think that's appropriate.

If he's made a mistake, let us know, because we want to rely and spend our money based upon what he's told us is fair and appropriate, and we believe we can do so without hurting anyone else. And we would like that chance. And we would ask that you remove the penalty and let us proceed.

Thank you very much.

CHAIRMAN LEMAY: Thank you.

Anything further in the case?

We'd like to get some draft orders, gentlemen.

MR. KELLAHIN: Yes, sir, I'd be happy to.

CHAIRMAN LEMAY: Two weeks?

MR. KELLAHIN: Shorter than that, if you like.

CHAIRMAN LEMAY: Ten days?

MR. KELLAHIN: Be happy to.

CHAIRMAN LEMAY: Thank you.

Anything else in the case?

MR. BRUCE: No, sir.

CHAIRMAN LEMAY: Thank you very much. We'll take the case under advisement.

(Thereupon, these proceedings were concluded at 4:12 p.m.)

* * *

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 Commission 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 November 10th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998