NEW MEXICO OIL CONSERVATION DIVISION

STATE LAND OFFICE BUILDING

STATE OF NEW MEXICO

CASE NOS. 10761 and 10762 (Consolidated)

IN THE MATTER OF:

(10761) The Application of Mewbourne Oil Company for Statutory Unitization, Lea County, New Mexico.

(10762) Application of Mewbourne Oil Company for a Waterflood Project and Qualification for the Recovered Oil Tax Rate, Lea County, New Mexico.

BEFORE:

MICHAEL E. STOGNER

Hearing Examiner

State Land Office Building

Thursday, July 1, 1993

REPORTED BY:

CARLA DIANE RODRIGUEZ
Certified Court Reporter
for the State of New Mexico

JUL 22 1993

COPY

A P P E A R A N C E S

FOR THE NEW MEXICO OIL CONSERVATION DIVISION:

ROBERT G. STOVALL, ESQ.
General Counsel
State Land Office Building
Post Office Box 2088
Santa Fe, New Mexico 87504-2088

FOR THE APPLICANT:

HINKLE, COX, EATON, COFFIELD & HENSLEY
Post Office Box 2068
Santa Fe, New Mexico 87504-2068
BY: **JAMES BRUCE, ESQ.**

I N D E X

E X H I B I T S

EXAMINER STOGNER: Call next case, No. 10761.

MR. STOVALL: The application of Mewbourne Oil Company for statutory unitization, Lea County, New Mexico.

EXAMINER STOGNER: Call for appearances.

MR. BRUCE: Mr. Examiner, Jim Bruce, from the Hinkle Law Firm in Santa Fe, representing the Applicant. I have three witnesses to be sworn, and I would request that this hearing be consolidated with Case 10762.

EXAMINER STOGNER: Okay. At this time I'll call Case 10762.

MR. STOVALL: Application of Mewbourne Oil Company for a waterflood project and qualification for the recovered oil tax rate, Lea County, New Mexico.

EXAMINER STOGNER: Other than the Applicant, are there any appearances in this matter?

At this time, will the witnesses please stand to be sworn.

[And the witnesses were duly sworn.]

EXAMINER STOGNER: Mr. Bruce.

MR. BRUCE: Call Mr. Cobb to the stand, first.

STEVE COBB

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. BRUCE:

Q. Would you please state your full name and city of residence?

A. My name is Steve Cobb, and I live in Midland, Texas.

Q. Who are you employed by and in what capacity?

A. I'm employed by Mewbourne Oil Company as district landman.

Q. Have you previously testified before the Division?

A. No, I have not.

Q. Would you please briefly state your educational and work background?

A. I graduated from Oklahoma State University in 1977 with a marketing degree, and completed the Oklahoma University PLM program in 1980.

For the last two years I have been

employed with Mewbourne Oil Company, and the 10 years prior to that I was with Santa Fe Minerals in Tulsa, Oklahoma. Three years prior to that I was with South Ranch Oil Company in Oklahoma City.

Q. As a landman, in those two previous capacities?

A. That's correct.

Q. Are you familiar with the land matters involved in these cases?

A. I am.

Q. You're currently based in Mewbourne's Midland office?

A. That is correct.

Q. And you are familiar with land matters, or part of your job responsibility is land matters in Southeast New Mexico?

A. That's correct.

MR. BRUCE: Mr. Examiner, I would tender Mr. Cobb as an expert petroleum landman.

MR. STOVALL: Are you a member of any professional associations?

THE WITNESS: AAPL and the PBLA, Permian Basin Landman Association.

MR. STOVALL: And the AAPL is the

American Association of Petroleum Landmen?

THE WITNESS: That's correct.

MR. STOVALL: Do you have any certifications by them yet?

THE WITNESS: No, I do not.

MR. STOVALL: Nothing further.

EXAMINER STOGNER: Mr. Cobb, you said you were in Tulsa with Santa Fe?

THE WITNESS: Santa Fe Minerals.

EXAMINER STOGNER: Which entity of Santa Fe Minerals?

THE WITNESS: Kuwait. It's not the railroad.

EXAMINER STOGNER: Not that that would matter, which Santa Fe it was, but it's hard enough. Okay, Mr. Cobb is so qualified.

MR. BRUCE: Mr. Examiner, before we begin in Case 10761, Mewbourne seeks to statutorily unitize the Querecho Plains-Upper Bone Spring Pool in a portion of Township 18 South, Range 22 East. The unit area does cover 2400 acres of land, and it is all federal minerals.

In the second case, Mewbourne seeks approval of a secondary recovery waterflood project for the unit, and certification of the recovered oil tax rate for the project.

Q. (BY MR. BRUCE) Mr. Cobb, referring to Exhibit 1, could you briefly identify that for the Examiner?

A. Exhibit No. 1 is a land plat which outlines our proposed unit area and identifies the separate tracts contained within that area. These tracts are divided on common mineral ownership, and there are currently 24 tracts in this unit area, and Mewbourne Oil Company or Curtis Mewbourne, operates 19 of the 24 tracts.

Q. Would you identify Exhibit 2, please?

A. Exhibit 2 is a bound volume of our unit agreement which was drafted on compiling unit agreements supplied to me through the BLM and other agreements that have been approved by the OCD.

The unit agreement describes the unit area, sets forth Mewbourne as operator, defines the unitized formation, and also provides for expansion of the unit area and basically sets out our relationship between all the parties involved in our unit.

Q. Okay. Now, Part I is the unit

operating agreement. What is the second part of that Exhibit 2?

A. Part I is the unit agreement and Part II is the unit operating agreement.

Q. So they're both contained in that volume?

A. That's correct.

Q. And this sets forth the duties and the authorities of the unit operator, and the relationships among the working interest owners?

A. That's correct.

Q. Now, as to tract ownership, would you describe how you identified or determined names of the working royalty interest owners in these tracts?

A. Several of the tracts we, Mewbourne, currently operate, and we have current Division Orders in-house or title opinions; so, for the tracts we operate, we went to our in-house records. For those tracts we do not operate, I had title opinions prepared on those.

Q. How many interest owners are there in the unit?

A. Originally there were approximately 74, 75 overriding royalty interest owners, one royalty interest owner, that being the United States or the BLM, and 50 working interest owners.

Q. How many are there currently?

A. Currently we have, I believe, 18 working interest owners, one royalty owner, and, again, a little over 75 overriding royalty interest owners.

Q. Is the decrease, from 50 to 18 working interest owners, due to purchases by Mewbourne?

A. That's correct.

Q. Referring to Exhibit 3, would you discuss what that is and identify the working interest owners?

A. Exhibit No. 3 is a booklet which lists all the working interest owners in the unit.

Q. That's on the second page of that booklet?

A. That's correct. The persons that have a "1" by their names have approved our unit. Those that do not have a "1" by their names have not approved our unit, and those are the ones we are seeking to unitize today.

Q. Okay. And behind the listing are just the signature pages from the various working

interest owners?
A. That's correct, to our unit agreement.
Q. And, moving on to the overrides and to Exhibit 4, would you discuss ownership of the overrides?
A. Again, this booklet sets forth the royalty and overriding interest owners. Page 1 lists those parties that have ratified our unit agreement and operating agreement. Those that do not have a "1" are, again, the parties we're seeking to unitize today. The third page to this book is the approval from the BLM.
Q. The preliminary approval?
A. The preliminary approval from the BLM.
Q. The other pages are the signature pages of the overriding and royalty interest owners?
A. That's correct.
Q. We've marked as Exhibit 4-A another signature page. Could you explain what that is?
A. I just received it this morning, by fax at this office, from Stephen Burleson, his signature page as an overriding royalty interest owner.
Q. And it was too late to fit it into the booklet?

A. That's correct.
Q. What percentage of working interests and overriding--or, I should say, royalty interest owners, have committed their interests to the unit?
A. One hundred percent of the cost-bearing working interest owners have committed their interest, and 99.01 percent of the overriding royalty interest owners have committed their interest.
Q. That's 99.01 percent of the override and royalty?
A. Which includes the BLM, that's correct.
Q. Now, as to those persons who have not yet committed their interests, I would refer you to Exhibits 5-A and 5-B. Could you very briefly discuss what Mewbourne did to obtain the commitment of those interests?
A. 5-A is a list of my contacts with the working interest owners that have not committed. The first one you'll notice is Lewis Burleson, and he has signed. The second one is Ann McReynolds, and she has signed. Both these parties signed yesterday.
The last one I have on there is

Clarence Stumhoffer, and, if you'll note, he has a 0.00 percent interest in the working interest.

Q. He owns a working interest in a tract, is that correct?

A. Right.

Q. But it is a nonparticipating tract?

A. That's correct.

Q. So he's not a cost-bearing working interest?

A. That's correct.

Q. And Exhibit 5-B, what does that relate to?

A. This relates to our efforts to secure the signatures of the overriding royalty interest owners by those people that have not signed yet.

Q. Could you just briefly touch on each person?

A. The first one we come to is Gary and Candace Jo Bennett. We have, either myself or people working with me, have talked to him, and he has indicated that he would sign. As of today, we have not gotten his signature in.

There is a typo on this page. On my last entry there it says, "Telephoned to ascertain if joinder to unit and lien executed."

"And lien" should not be in there.

Q. Now, the contacts with them were just over the past month. Could you explain why this is?

A. The reason for this is, the BLM had requested that we put an additional tract into our unit.

Q. And that was quite recent, wasn't it?

A. Right. It was Tract No. 1, that we had not originally intended for it to be in our unit. After meeting with them, they requested we add it into there. We did that, had a title opinion prepared to ascertain ownership, and these are the overriding royalty interest owners. Again, these people in this tract have an overriding royalty interest, but a zero participation.

Q. Could you move on to the other pages?

A. John Borg, II, we have been trying to locate him since 1985. We currently have money in suspense for him. We've advised him of that. Mr. Calvert of our office has talked to him, and he has advised Mr. Calvert that he'll participate, but as of this date we have not received any response from him. And he's not followed up on any of our attempts to release the money we're holding in suspense for him.

Q. The suspense money has to do--

A. --with other wells he's in, that's correct. Richard Borgaard, again, this is the Tract No. 1 that we were dealing with, and we've not been able to find him. We've called Anadarko, who operates that tract, and have spoken with their division order analysts, and they've advised us that they've been trying to look for him for several years, and that they have money in suspense theirselves for him, and cannot find him.

We found one Mr. Borgaard in Bend, Oregon, which was not the same one. Had no idea who he was. We're basically at a dead end in trying to locate him.

Q. Again, he has a zero participation in the unit?

A. That's correct. Pamela Brooks, she has advised us by telephone that she was reviewing it and she wasn't sure at this time. That was on June 8th, was the last telephone conversation we've had with her, and we've not heard back from her.

Stephen Burleson is signed. He signed today. That's our Exhibit 4 we just talked about.

Q. 4-A?

A. 4-A. William J. Casey, again, the last address we had on him was 1973, in New York, New York. Again, we visited with Anadarko, who operates the tract. This is that same Tract No. 1. And we've not been able to locate him. Again, Anadarko has this interest in suspense. We'll keep trying to find him; and, if they have any luck, they'll notify us.

MR. STOVALL: This isn't the former CIA director?

THE WITNESS: No. That's what they asked me. Well, everybody knows where he is.

[Discussion off the record.]

A. Nancy Hayes is Lewis Burleson's daughter and Steve's sister. She is out of town right now and unable to sign. However, her father and brother have both indicated that she will sign once she gets back from vacation.

Rae Little, again we've been trying to notify her and contact her since 1985, because of money we have in suspense for her. We have approximately $5,000 in suspense for her.

Q. She is deceased?

A. That's correct, but her estate has not been probated, is our understanding. And Mr. Calvert has had numerous conversations with the Little family, and has advised them of this money in suspense and of our trying to get the unit approved, and they've not responded to his inquiries.

Q. They haven't responded to inquiries for several years?

A. That's correct. Ann H. Johnson McReynolds has signed. We could delete this. She signed yesterday.

Margaret Johnson McCurdy is out of town until July 5th. Her secretary indicated to us that she doesn't know why she would not sign, "But I cannot act on behalf of her," is what she said. She has no reason why she wouldn't, but there's nothing she can do until she gets back.

Q. Again, this is Tract 1, and this is a nonparticipating interest?

A. That's correct. Lita Sabonis, again we've had numerous contacts with her family. We're just unable to get in touch with her. Her family has given us her address and it's the same address we had in our files, and we're unable to get her to call us back. We've talked to all her relatives but can't get her to contact us. As a matter of fact, her relatives have signed this agreement. She's just hard to get ahold of or will not accept our calls, or whatever.

Gladys Shannon has advised us that she is involved with the Trammell Estates, who are the next people on this report. They've looked at this and they've sent us a letter advising that they will not sign. They have zero participation, why should they sign. That's the bottom line. They sent us a letter to that effect, and Gladys Shannon told us, "I'm going to do whatever the Trammell Estates does," and we've received a letter that they're not going to sign, "It's too small. We're not interested."

Q. So Shannon and all three Trammells--

A. --and all three Trammells are the same.

Q. And they are in Tract 1, which has a zero participation?

A. That's correct.

Q. And you mentioned that there were two unlocatable interests, William Casey and Lita

Sabonis. Could you describe what Exhibit 6 is?

A. Okay. Exhibit 6 is an affidavit of publication in the Hobbs newspaper, where we're asking for--just to put notice of what we're trying to do here, and for them to please notify us if we can find them.

Q. It was a publication notice to cover all your bases?

A. That's correct.

Q. There's one extra person listed on there, a Gregory Panos. Did you subsequently locate him?

A. Yes. I acquired his signature.

Q. In your opinion, has Mewbourne Oil Company made a good-faith effort to secure voluntary unitization of all the tracts?

A. Yes, we have.

Q. Has written notice of the unitization hearing been given to all locatable parties who did not voluntarily join?

A. Yes, it has.

Q. Is Exhibit 7 your affidavit of notice?

A. Yes, it is.

Q. The letter on that Exhibit 7 lists a number of people. Although the certified return receipts attached are just some of those people, the people whose return receipts are omitted have since signed?

A. That's correct.

Q. As to the unit operating agreement, does it contain a provision for carrying working interest owners?

A. Yes, it does, that would be Section 10.4.

Q. Does the operating agreement provide for a penalty against nonconsenting interest owners?

A. Yes. Section 10.5 provides for cost plus 200 percent.

Q. In your opinion, is this a fair penalty?

A. Yes, it is.

Q. Do operating agreements in this area typically contain similar penalties?

A. Yes, they do.

Q. 100 percent of the cost-bearing working interest owners have agreed to this penalty, have they not?

A. Yes, that's correct.

Q. What overhead rates does the unit

operating agreement provide for?

A. Currently, it provides for $6,577 drilling well rate, and $680 as a producing well rate.

Q. You said the drilling well rate was what?

A. $6,577.

Q. We'll get to that in a minute. These rates will be adjusted annually, under accounting procedures?

A. That's correct.

Q. Now, since the booklet with the unit operating agreement was printed, have there been some changes to the unit agreement?

A. Yes, there have.

Q. Referring to Exhibit 8, would you describe briefly what they are? And these are to the unit operating agreement?

A. That's correct. All right. Exhibit No. 8 reflects the changes we've entered into with a couple of companies. On page 24, we originally, on Article 10.5, six lines down, we originally had 30 days.

Q. To pay costs?

A. To pay costs. We have agreed with

Santa Fe Energy to amend that to 90 days.

Q. What's the next change?

A. Page F-10, paragraph 1.2 was amended, and in paragraph 1.3 the drilling well rate was changed from $6,577 to $5,400.

Q. So the drilling well rate will now be $5,400 instead of what's printed in the original booklet?

A. That's correct. The producing well rate will remain the same. That was at a request from Anadarko.

Q. And finally, on page F-12, was there a change?

A. F-12, Item 4 was amended.

Q. And those were just changes in language, I believe?

A. Right.

Q. Will all working interest owners benefit from these changes?

A. Yes, they will. However, I wanted to add one other change we agreed to with Anadarko. We agreed that Mewbourne Oil Company agrees to allow the operating committee to approve the hiring of outside consultants. That was at the request of Anadarko, and we have agreed to that.

Q. These changes are to the benefit of the nonoperating interest owners, are they not?
A. That's correct.
Q. Now, as far as the unit agreement itself, and referring to Exhibit B, which is the tract schedule, are there any minor changes that will be made on here?
A. Yes, there are. At the request of the BLM, we have agreed to make the following changes. Tract 3 and 13 are reversed; in other words, Tract 3 will be 13, and 13 will be 3. They have also requested where we have basic royalty and percentage, that column, where we have 12 and a half percent, the BLM has requested us to put Schedule B in lieu of the 12 and a half percent. Just the words "Schedule B."
Q. That doesn't affect all those tracts, does it?
A. No, just those tracts that have a sliding scale will. And, I believe that is all that they've requested.
Q. The BLM changes don't change any of the participation factors?
A. No, they do not.
Q. In your opinion, will the granting of

these applications be in the interest of conservation, the prevention of waste, and the protection of correlative rights?

A. They will.

Q. And were Exhibits 1 through 8 prepared by you or under your direction or compiled from company records?

A. They were.

MR. BRUCE: Mr. Examiner, I move the admission of Mewbourne Exhibits 1 through 8.

EXAMINER STOGNER: Exhibits 1 through 8 will be admitted into evidence at this time.

EXAMINATION

BY MR. STOVALL:

Q. Mr. Cobb, it appeared to me, from looking at the exhibits, that none of the parties that would be forced into the unit by the effect of the order, their participation or share will be the same whether it's voluntary or compulsory; is that correct?

A. That's correct.

Q. Any party who would be affected by cost issues, such as overhead rates, penalty rates for participation, et cetera, has signed the agreement and agreed to those?

A. That's correct. I do have a hundred percent.

MR. STOVALL: I don't have any other questions with respect to the land issues in the case.

EXAMINATION

BY EXAMINER STOGNER:

Q. So, only noncost-bearing parties, pursuant to your question, Mr. Stovall, are being affected with this particular action?

A. That's correct.

Q. I assume when the application was made, that, however, was not the case?

A. That's correct.

Q. Now, if I go to my Exhibit No. 1 and find Tract 3, I need to change that to 13?

A. That's correct. And then, of course, 13 to 3.

MR. STOVALL: Do you know why the BLM wanted to change those numbers?

THE WITNESS: They wanted these tracts in order of date, the earliest lease being Tract No. 1. So, 13 was dated before 3.

MR. STOVALL: This isn't some sort of bureaucratic thing, is it?

THE WITNESS: No. No.

EXAMINER STOGNER: I have no questions of this witness. He may be excused at this time. Thank you.

KEVIN MAYES

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. BRUCE:

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

A. My name is Kevin Mayes, and I reside in Tyler, Texas.

Q. What is your occupation and who is your employer?

A. I'm a petroleum engineer with Mewbourne Oil Company.

Q. Have you previously testified before the Division as a petroleum engineer?

A. Yes, I have. As a matter of fact, I presented testimony in Case No. 10497 in July of 1992. This resulted in Division Order No. R-9737, giving Mewbourne permission to test the injectivity of the First Bone Springs sand at Querecho Plains.

Q. So, you are familiar with the engineering matters related to the proposed unit and the waterflood for the unit?

A. Yes, I am.

EXAMINER STOGNER: What was that R number again?

THE WITNESS: R-9737.

EXAMINER STOGNER: Okay.

MR. BRUCE: Mr. Examiner, I tender Mr. Mayes as an expert petroleum geologist.

EXAMINER STOGNER: Was the order granted?

THE WITNESS: Yes, it was.

EXAMINER STOGNER: Okay.

MR. STOVALL: Then he's qualified.

EXAMINER STOGNER: I'm sorry, Mr. Bruce.

MR. BRUCE: I was just asking if the witness was considered qualified as an expert petroleum engineer.

EXAMINER STOGNER: Yes, he is.

Q. (BY MR. BRUCE) Mr. Mayes, referring to Exhibit 9, what is the unitized formation?

A. Exhibit No. 9 is a type log for the field. It's a density neutron porosity log run in November 1987. It was run in Mewbourne Oil Company's Federal "L" #4 well. That well is located in Section 23, Proration Unit B.

For the Examiner's convenience, we've submitted a full section of that log to him, and I believe he'll find the unitized formation depths probably two-thirds of the way through that complete log, starting at approximately 8300 feet.

EXAMINER STOGNER: 8328?

THE WITNESS: The actual depth will be 8328 through 8620 feet in this well. And then, of course, the unitized formation will be all the strata that is geologically correlative to this interval underlying the unitized area.

Q. And this formation is designated by the Division as the Querecho Plains Upper Bone Springs Pool?

A. Yes, it is.

Q. Would you refer to Exhibit 10 and discuss the continuity of the formation?

A. Yes. Exhibit 10 is the stratigraphic cross-section across the unit area. To refresh everyone's memory, the two major sands located in the unitized formation Mewbourne has identified as the green sand and the blue sand, and again this cross-section is presented today to demonstrate that the sands are continuous across the unitized area.

Q. This was presented in the prior hearing, also?

A. Yes, it was.

Q. Would you refer to Exhibits 11 and 12 and discuss the outline of the unit area?

A. Exhibit No. 11 will be a net high isopach above the water/oil contact for the green sand, and Exhibit 12 will be the same isopach for the blue sand.

The reservoir is defined by porosity pinchouts on the north, east and west sides, and the water/oil contact on the south side.

Q. Does the proposed unit cover the entire Querecho Plains Upper Bone Springs Pool?

A. No, there are certain fringe areas of the reservoir that were omitted for economic considerations. However, we do have 100 percent of the cost-bearing participants agreeing to this unit boundary, as well as 99 percent of the royalty interests agreeing to the unit boundary. That includes the Bureau of Land Management's designation of this unit area.

Q. And I believe Mewbourne had a couple of meetings with the BLM to discuss the outline of this unit?

A. That's correct.

Q. Referring to Exhibits 13 and 14, would you describe the history of the proposed unit area?

A. Exhibit 13 is a plat showing the development of the field. The discovery and initial commercial production came from Shell Oil Company's Querecho Plains #2 well, which is located in Section 27, Proration Unit M. It was brought onto production in April of 1959.

Quite a time lag occurred, then, before more attempts were made to complete the Upper Bone Springs Pool. Next attempts were made in 1980, with two attempts made down in Section 34. And then Mewbourne completed their Federal "G" #1 well, which is located in Section 27, Proration Unit K, in 1984, and then the field developed to the north/northeast in a fairly rapid fashion.

There were 35 completion attempts made within the unit area. There are currently 32 producing wells from the proposed unitized formation within the unit area. The spacing on the wells is 40 acres.

MR. STOVALL: How much? Say it again.

THE WITNESS: 40 acres.

Q. And Exhibit 14, please?

A. Exhibit 14 is a graphical representation of production from the unitized area and associated prediction of the primary depletion for the field. Peak production was 29,950 barrels per month. That occurred in May of 1986. Production was fairly flat, then, during the development phase, until late 1989, and the field went on an approximate 40 percent nominal decline rate.

Cumulative oil production through October of 1992 is 1,556,000 barrels. Cumulative gas is approximately 5 Bcf. The drive mechanism is solution-gas, with the current GOR being 6,700 standard cubic feet per stock tank barrel.

The reservoir pressure, the original pressure in the reservoir was 3,341 psi. It has now declined to 705 psi. Our remaining predicted primary production as of November 1, 1992, is 473,376 stock tank barrels.

Q. Is the unit area in an advanced state

of depletion with respect to primary production?
A. Yes, it is. The wells currently average seven barrels of oil per day.
Q. Has the portion of the pool which you propose to unitize been adequately defined by development?
A. Yes, it has.
Q. Is this portion of the pool suitable for unitization and waterflooding?
A. Yes, we believe so. There are no Bone Springs sand waterfloods in New Mexico, to the best of my knowledge. However, the results of two injectivity tests, the continuous nature of the sands and the results obtained from computer modeling, suggest that this formation is suitable for a waterflood.
Q. When did Mewbourne Oil Company first consider unitizing this pool?
A. The reservoir was first considered a potential EOR candidate with fluid and core analysis work performed in late 1987.
Q. And, referring to Exhibit 15, would you discuss the feasibility study which was prepared for the proposed unit?
A. Yes. Exhibit 15 is a third-party

consultant's report on the pool. In particular, it's Petresim Integrated Technologies out of Houston, Texas. The report is submitted in its entirety, as it contains some very good summaries of the fluid work and rock work that we did. It also has a complete reservoir description in it, and, of course, the production predictions for primary depletion as well as waterflood operations.

Q. Has Mewbourne done anything to confirm the study prepared by Petresim?

A. Yes. As a result of our hearing last year and as a result, actually, of a June 1992 operators' meeting concerning this project, we applied for and received the Division Order from last year, the Division Order R-9737, to test the injectivity of the sand.

Q. And, moving on to Exhibits 16, 17 and 18, would you discuss them together and the results of the injectivity tests?

A. Yeah. Exhibit 16 is going to be a plat showing the location of the two injectors.

Exhibit 17 is going to be a performance curve for the Government "K" #2 well, which was one of the two test wells.

Exhibit 18 is a performance curve for the Federal "E" #11 well. Petresim's simulation suggested these wells would only take 200 barrels of water per day, and, as one can see from the performance curves, we got injectivity along the lines of 700 to 800 barrels per day. This was much better than we were anticipating and is very encouraging to us.

Q. Referring to Exhibit 19, what injection pattern will you use for the waterflood?

A. Exhibit 19 is a plat showing our proposed initial injection pattern. This pattern is the optimum pattern as it was determined by Petresim's computer modeling work.

Q. And it's a line drive model?

A. Yes, it is, line drive with the injectors aligned east/west.

Q. Okay. Let's move on to Exhibits 20, 21 and 22, and will you discuss the predicted performance of your waterflood?

A. Yes. Exhibit No. 20 is Petresim's predicted production under waterflood operations. This prediction, I'll make a note for the Examiner, is slightly different from what's presented in their report, as this prediction in Exhibit 20 takes into account modifications for the injectivity tests being better than we thought they were going to be.

Exhibit 21, then, is a graphical representation of Petresim's prediction, and Exhibit 22 is a graphical representation of the difference in the oil production that will be obtained during waterflood operations versus primary depletion.

Again, you can see on Exhibit 22, the remaining primary for the pool would be 473,376 barrels of oil, and the incremental oil, due to the waterflood, is predicted to be 1.4 million barrels of oil.

Q. Referring to Exhibit 23, would you just briefly discuss the economics of the proposed unit?

A. Yes. Exhibit 23 is a summary of the economics. You can see the initial capital investment required for this project is $2,850,000. If one uses the 1.4 million barrels of incremental oil, it generates approximately $14 million of present worth to the working interest owners as a group.

The return on investment will be 5.9 to

1, and the internal rate of return will be 52 percent. Also listed in Exhibit 23 is the benefit to the BLM and the benefit to the overriding royalty interests as a group.

I'll note these economics do have the BLM royalty reduction Schedule B taken into consideration, as well as the state's EOR.

Q. Will the oil and gas recovered by unit operations exceed unit costs plus a reasonable profit?

A. Yes, it will.

Q. What is the estimated life of the waterflood?

A. Approximately 12 years. We believe the waterflood operations will extend production into the year 2005.

Q. Is the unit area so depleted that it's prudent to apply an enhanced recovery program?

A. Yes, it is.

Q. In your opinion, is the waterflood application economically and technically feasible at this time?

A. Yes, it is.

Q. Will waterflood operations in this portion of the pool prevent waste?

A. Yes, it will.

Q. And will they result, with a reasonable probability, in increased recovery of substantially more hydrocarbons than would otherwise be recovered?

A. Yes, it will.

Q. In your opinion, will unitization and secondary recovery operations benefit the working and royalty interest owners in the portion of the pool being unitized?

A. Yes, it will.

Q. Will unitization of just a portion of the pool adversely affect the nonunitized portions of the pool?

A. No. If anything, offset operators may receive some pressure maintenance from our project in the fringe areas.

Q. Let's move on to Exhibit 24. Will you identify that?

A. Yes. Exhibit 24 is the New Mexico State Form C-108. It was submitted with our application, and it is required in order to inject fluids.

Q. Would you please discuss your proposed injection wells?

A. Yes. Pages 2 through 16 of the C-108 are schematics of all of our proposed injection wells.

Q. And the pages of the C-108 are numbered for the ease of the Examiner?

A. For the convenience of the Examiner, yes, sir.

Q. Go ahead, Mr. Mayes.

A. If I could refer everybody to page 2, on the first schematic, how we calculated the top of cement is documented on that first schematic, and how we calculated that top of cement is used throughout the C-108.

It was calculated using the appropriate cement yield at 25 percent reduction to this yield, and no consideration was given to casing collars.

It is our intention to set a packer within 100 feet of the top perforation and use noncoated tubing.

Q. Would you please discuss the wells in the area of review.

A. Yes. The area of review is defined as a one-half mile radius around each injector. Pages 18 through 23 of the C-108 contain a spread sheet list of all mechanical information for wells within this area of review which penetrate the unitized formation.

Q. Are there any plugged and abandoned wells within the area of review?

A. Yes, there are. Pages 24 through 27 contain schematics of all plugged and abandoned wells.

Q. To the best of your knowledge, is the mechanical integrity of all of these wells sufficient for you to conduct your waterflood operations?

A. Yes, I believe so. However, I would like to discuss the Federal E #1 well, as it was the topic of our last hearing.

EXAMINER STOGNER: What page am I going to find that on?

THE WITNESS: We're going to submit a new exhibit.

Q. If you could, Mr. Examiner, refer to Exhibit 25, and I'll refer Mr. Mayes to that, and discuss the Federal E #1 well. And, as you said, this was brought up at the hearing last July, was it not?

A. That's correct. Exhibit 25 are some

calculations concerning the E #1 well. The concern with the E #1 well is that the calculated TOC, top of cement, does not cover the First Bone Springs sand. We did a thorough check of our records and indeed we did not run a temperature log or a cement bond log to verify this top of cement.

However, we do have a caliper log, and these calculations reflect using the caliper volume at 100 percent slurry volume, and taking casing collars into account. However, the calculated top of cement is 10,666 feet, and it still does not cover the First Bone Springs sand.

However, in defense of not reentering the E #1 for potential squeeze operations, I would like to offer up some items for defense.

First of all, the mud that is in the annulus between the 5-1/2" casing and the wellbore, is an 11.8 pound per gallon mud. This is a very heavy mud. We tried to find the mud records and find the additives that were actually added to this mud, and we could not find them.

However, an 11.8 per pound gallon mud, we suspect, has substantial amount of gel and possibly barite used to weight it up that heavy.

One of the items in the Division Order that was issued last year, was that we would monitor the casing annulus on this E #1 well to see if any pressure would occur on the surface. We've monitored that casing spool at the surface for almost a year now and have never seen any pressure on that annulus.

The E #1 well is the direct west offset to one of our test injection wells, also, and we injected 50,000 plus barrels of water into that test injector, which is getting close to being a fill up volume for the E #1 area. Again, if we were going to see pressure at the surface of the E #1 on that annulus, we would have expected to see it during injection procedures in the offset test well; but, again, we never did see any pressure there.

I would like to reiterate some testimony I gave last year concerning this issue. This very heavy mud has been in that annulus for approximately 20 years now. I've had similar experience in trying to circulate cement into an annulus after a heavy mud has been located there for this length of time, and our experience was that we punched some holes in the casing and tried to circulate some cement into the annulus, and what we ended up doing was just exceeding frac gradient, and we never could get that mud to move in that annulus again. It had set up to a point of having almost immobile properties.

Our concern with reentering the E #1 would be that we would try cement and squeeze operations and essentially the same thing would happen to us. We would exceed frac gradient and we would squeeze our cement out into the frac plane and we would never get any cement circulated into that annulus.

Another point I'll make is that mud-laden fluids are used in plugging and abandoning wells, and that mud-laden fluid is trusted to keep cross-flow from reservoir to reservoir from occurring.

I also might go back, excuse me if I can and revert a little bit, down at the bottom of this Exhibit 25 are some hydrostatic calculations for that mud. That mud, 11.8 pound per gallon mud, generates a hydrostatic head at the top of the Bone Springs formation of 5,106 psi. And I'll remind you that the virgin pressure for the Bone Springs pool was 3,341 psi, and the maximum predicted reservoir pressure we anticipate during waterflood operations is 3,971 psi.

Just strict hydrostatics would dictate that nothing will enter the annular area from the First Bone Springs formation, due to this heavy mud.

Q. As part of your tests, you did monitor the annulus of the E #1?

A. Right. We've monitored that annulus for about a year now, and we've still not seen any pressure on that annulus. The E #1 does contain significant Morrow gas reserves. It's currently producing out of the Morrow formation. We feel that reentering that well provides a tremendous amount of risk to losing those gas reserves, so we would again request that monitoring this wellbore be allowed, versus reentering that wellbore.

Q. Is it in the best interest of the working interest owners to keep all injected water in the unitized formation?

A. That's correct. You lose efficiency

with a waterflood any time you let water out of the unitized formation, and we will make every effort not to let that happen.

Q. Will you please discuss your plans for reworking the injection wells?

A. The proposed injection wells are all currently producing and will require removal of rod pump equipment. We plan to install a packer within 100 feet of the top perforation in each well, and have an inert fluid circulated into the casing tubing annulus. All injectors will receive acid treatments during their conversions, and all wellheads will have pressure gauges installed on the tubing and casing annuli.

Q. What additional facilities will Mewbourne Oil Company need to install for the unit and the waterflood?

A. We propose both a central injection facility and a central production facility. The injection facility will consist of appropriate storage capacity, filters, meters and injection pumps. The production facilities will consist of appropriate storage, separating equipment, meters and sales hookups. Produced water will be reinjected, and all flow lines will be rerouted accordingly. A water service line approximately three miles in length will be built to connect to the City of Carlsbad's Double Eagle system.

Q. What injection pressure do you request approval of?

A. The projection prediction we obtained from computer modeling is based on injecting at a surface pressure at 2,000 psi, and we would request allowing that 2,000 psi as the maximum injection pressure.

Q. Referring to Exhibit 26, could you discuss the basis for your request?

A. Yes. Again, Exhibit 26 contains calculations showing the frac gradient will not be exceeded with the 2,000 psi surface pressure.

Again, this 2,000 psi surface pressure was a topic of our July 92 hearing. The Division's Order allowed for a tubing pressure of 1,650 psi, with a procedure for administrative approval for 2,000 psi. It turns out that we use produced Delaware water as source water for testing those injectors, and it was much heavier than we anticipated, so administrative approval was never sought.

The gradient hydrostatic head for this

Delaware water was .51 psi per foot, and generated a total head of .70 when 1,650 psi was added to it.

The injected fluid for the full flood will be a mostly low-dissolved-solids content water from the City of Carlsbad. If one uses a .45 fluid gradient for that City of Carlsbad water, and a 2,000 psi surface pressure, one calculates a total head of .69 psi per foot, well below the frac gradient, and the frac gradient is established as the .74 for the pool.

Q. Is this request supported by the results of your injectivity tests?

A. Yes, it is. I'll refer everyone to Exhibits 27, 28 and 29, which showed that the water stayed contained in the Bone Springs during those injectivity tests.

Exhibit 27 is a pressure gradient survey confirming the head of the Delaware water was .51 psi per foot and, as a result, we were injecting at .70 psi per foot during our test.

And Exhibits 28 and 29, are injection surveys showing that the water stayed contained within the unitized formation. You can see on the second page of the--well, let's take Exhibit

28 which is the profile survey for the Government K #2 well, you can see on Page No. 2 of that exhibit that the survey company concluded that no fluid moved above the top perforation.

Page No. 2 which is very busy, and I kind of apologize for that but, it has a series of temperature logs run at various shut-in periods to verify that the water did not go past the bottom perforation.

Then Exhibit 29 is going to be a similar profile log for the Federal E #11, and again these two profile logs on our two test wells do show that the wells stayed contained, and we will be injecting at a lower gradient than we were during these tests, during our whole flood operations.

Q. Of the injection water, what percentage do you anticipate will be fresh water from the Carlsbad system?

A. Approximately 90 percent should be City of Carlsbad water. And 10 percent we hope to pick up as produced water from various offset operators in our own operations.

Q. Will this be a closed system?

A. Yes, it will.

Q. Are there any fresh water sources within a mile of the proposed injection wells?

A. There are no active fresh water wells, according to the New Mexico State Engineer's Office. There was an attempt to develop a water well in Section 26; however, it was dry and abandoned.

Q. Are there any faults or hydrologic connections between fresh water sources and the injection point?

A. No, there are no faults, to my knowledge, and all wellbores have casing said to a depth sufficient to cover known fresh water sources in the region.

Q. Is the proposed injection water compatible with the formation water?

A. Yes. An analysis is presented on pages 30 through 36 of the C-108. This report was prepared by a commercial laboratory and indicates minimal compatibility problems exist.

Q. Is the unitized management, operation and development of this pool necessary to effectively carry on secondary recovery operations?

A. Yes, it is.

Q. And, in your opinion, will it substantially increase the ultimate recovery of oil from the unitized portion of the pool?

A. Yes, I believe so.

Q. In your opinion, does the unit agreement provide for a fair and equitable plan of unitization?

A. Yes, it does.

Q. Mr. Mayes, if you could refer back to Exhibit 2, could you describe how production will be allocated among the tracts under the unit agreement?

A. Yes, and we are referring back to the unit agreement, if everybody wants to get that back out.

Q. And what pages in particular do we want to refer to?

A. I'll refer everyone to pages 6 and 7 of the unit agreement, and that will be Articles 2.23 and 2.24. What we propose is a two-phase allocation formula, the initial phase defined as the primary phase and Article 2.23 is set up to allocate the remaining primary reserves of the reservoir to the separate tracts.

Then, on page 7, we propose a later

phase, which is defined as the secondary phase in Article 2.24, and it is set up to allocate the secondary reserves, i.e., the 1.4 million barrels of oil, and the capital costs associated with these secondary reserves.

Referring back to page 6 real quick, the primary phase will be in place until the total unit remaining primary is produced, and again that volume is determined to be this 473,376 barrels of oil as of November 1, 1992.

I'll refer everybody ahead to page 22 real quick. The proposed primary formula is 100 percent remaining primary reserves as they were determined by decline curve analysis, i.e., the tract remaining primary divided by the total unit remaining primary. The production will then be allocated to the tracts based on the secondary formula, which we propose is 100 percent ultimate primary oil, as determined by decline curve analysis.

Q. In your opinion, does the participation formula allocate the produced, and saves hydrocarbons to the individual unit tracts on a fair, reasonable and equitable basis?

A. Yes, we do.

Q. What is the initial project area for the waterflood?

A. The initial project area pursuant to Division Rule 701(G)(3) will encompass 1,280 acres, all located inside the unit boundary.

Q. What project allowable does Mewbourne request?

A. Mewbourne would request that each producing well be granted an allowable equal to its capacity to produce.

Q. And do you request that the order entered in this matter contain an administrative procedure for approving unorthodox well locations or for changing producing wells to injection wells?

A. Yes. In order to optimize the waterflood in the future, it may be necessary to convert producing wells to injectors, or to drill additional wells at unorthodox locations and we would request that an administrative procedure be established in the order to accomplish this.

Q. Is your proposal submitted as Exhibit 30?

A. Yes, it is.

Q. Was notice of the waterflood sent out as required by Form C-108?

A. Yes, it was. We notified all operators and lessees within one-half mile of the proposed injectors, together with surface owners and all lessees of surface rights.

Q. Is Exhibit 31 your affidavit regarding notice?

A. Yes, it is. It contains the return and certified receipts.

Q. In your opinion, will the granting of this application be in the interests of conservation and the prevention of waste?

A. Yes, it will.

Q. Were Exhibits 9 through 31 prepared by you or under your direction, or compiled from company records?

A. Yes, they were.

MR. BRUCE: Mr. Examiner, I move the admission of Exhibits 9 through 31.

EXAMINER STOGNER: Exhibits 9 through 31 will be admitted at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Mayes, on Exhibit No. 30, this is your proposed rules, there's a lot of information that's been simulated, so forgive me if I'm repeating a few things I might have missed.

Are you going to propose an administrative procedure for injection increase or--I know the 2,000 psi is over the .2 psi per foot to the uppermost perf that we require. Is your 2,000 going to be the maximum throughout the lifetime, or do you anticipate a higher injection pressure?

A. No, sir. 2,000 psi will be our maximum pressure throughout the life.

Q. In reviewing your schematic for your injection wells, you'll be using 2-7/8" or 2-3/8" tubing for your proposed injection wells?

A. Right.

Q. First of all, how many injection wells total?

A. 15 will be converted. Of course, two are already converted and 15 total.

Q. I notice that there is no proposal or plan for plastic-lined or lined tubing, that you're going with bare steel. What is the configuration on the two existing injection wells at this time?

A. They both have bare steel in them. We ran some corrosion coupons in our injection lines during our test and, after running analysis on those coupons, it was established the corrosion weight was approximately 1.6 mil per year. I have experienced in floods where corrosion rates of four and five mils per year was obtained, or effective. And throughout an eight-year life that I worked with that waterflood, we never had any tubing problems associated with that high of a corrosion rate.

Q. And, if I heard correctly, your water source will be at least 90 percent City of Carlsbad. Is this fresh water, or is this from the sewer system?

A. It's their Double Eagle System which, I believe, it's Caprock water. We have an analysis of it which is located in that C-108 water analysis package, the latter pages of the C-108, and I believe--well, let me just give you the correct TDS content of that water.

Okay, total dissolves solids--

Q. Which page are you on?

A. I don't have a numbered one.

MR. STOVALL: Page 31. Is it the letter from Caprock Laboratory?

THE WITNESS: Yeah. Just following that are some analysis sheets.

A. Page 33 is the Double Eagle analysis, and they've got a number down the left side of that page, No. 16 is the total dissolved solids content of the water, 8,213 parts per million.

Q. Do you know what formation this water is from?

A. I really don't know, exactly.

Q. Do you know where their well is located, or is this from a system?

A. Yeah, their wells are north and east of us, a good 15, 20 miles, and then their system runs several miles to the City of Carlsbad.

Q. But this is one of the systems or one of the wells, whatever the case may be, that feeds fresh water into the City of Carlsbad?

A. Yes, and it's quite an extensive system ride. It is permitted and tapped for industrial use all along its way, also.

Q. And you would just be picking up a portion of it?

A. Correct.

Q. You said 10 percent, would that be reinjected source water from your proposed injection, or would there be other produced waters from outside this unit?

A. It will be both. We'll recycle all the unit-produced water, as well as we have offset operators to us producing fairly substantial amount of Delaware water that we're negotiating to take off their hands for them.

Q. Is there a technical reason or formation or geologic reason why 100 percent produced water or reinjection water could not be utilized in this project?

A. Well, during the life of the flood, currently the flood, all the wells in the unit, produce approximately 100 barrels of water a day, and we require 10,000 barrels of water a day for the flood. As the flood matures and the producing wells break through, of course, the produced water will increase.

Is that your question? I don't know if I understand you correctly.

Q. Yes, and in fact you're going into it to the detail that I think is applicable. Throughout the life, what are you going to be seeing and what kind of changes?

A. We estimate that probably three years into the life of the flood we'll be cycling 80 percent of our water and only receiving 20 percent of our water from the City of Carlsbad.

Of course the TDS content of that produced water is going to be breakthrough water that will have City of Carlsbad quality or Bone Springs quality and we feel like the total dissolved solids of the water is not going to increase substantially over the life of the waterflood, over the life of cycling that water.

Q. Say in about another 10 to 15 years, when you're utilizing, say, 80 percent reinjection as opposed to 20 percent City water, essentially makeup water at that point--

A. Right.

Q. --what kind of water analysis would you expect, as far as total dissolved solids?

A. Well, I haven't done that calculation so it's hard to give you a hard and fast number; but, if one looks at that, this analysis in the back of the C-108, there's a Bone Spring analysis.

Q. I believe that's page 34.

A. That's correct. And you can see that the dissolved solids of this water is 149,000 parts per million, but the water that's actually going to be Bone Spring-produced water is going to be so diluted by the City of Carlsbad water that I would anticipate that that total dissolved solids would not appreciably increase over 8,000 parts per million.

Again, you know, I haven't done those calculations and it's hard to give you a hard and fast number.

Q. Your water analysis shows no hydrogen sulfite?

A. Right.

Q. So this is a sweet oil pool?

A. The temperature of the reservoir is 130, 140 degrees, and I would anticipate that any bacteria that might form H2s during the life of the project will be killed at those temperatures. We're not anticipating a heavy H2s problem.

Q. My concern at this point is bare steel, allowing it at this point, and what happens in the future.

A. Well, I would submit that, again, we are going to have an inert fluid in between the tubing and casing annulus on all of our injection wells, and we'll be monitoring the pressure of that annulus at the surface. If we would have a tubing leak occur, we're going to be able to see it very quickly. And if it appears to us that bare steel is going to become a problem, then in the future we might consider coating our tubing at that time. But we would propose initially, going into the flood, that we use bare steel and monitor the situation.

Q. Is the grade of tubing that you're utilizing just standard, oil field grade, regular production-type tubing, or anything special?

A. It's standard N80 J55 tubing.

Q. In referring to your C-108, Exhibit No. 24, starting with page 18, this is your review of wells within the area of review, the half-mile area?

A. Uh-huh.

Q. When you show tops of cement, were these all calculated or were any of them from temperature surveys, or were they from various means?

A. For the most part they're calculated. However, there are some that the column--I'll refer you to the first page, the third well down has some letter symbols in parentheses next to the top of cement?

Q. You're talking about the Mewbourne Federal M #1 and the letter V, as in Victor, shows up?

A. Right. The "V" stands for visual. In other words, I actually saw the cement come back to surface on those wells. There are some other letter designations. There's a CBL, little "B" in parenthesis occasionally, which stands for Cement Bond Log, and this is all labeled on the last page of that spreadsheet--well, was. I take that back. It's not. I apologize.

A V is for Visual, and a CBL is for Cement Bond Log, and I believe those are the only two notations that--yeah, those are the only two notations that I put in there. All the rest will be calculated tops of cement.

Q. Pursuant to the same calculation that you utilized on page 2 of the C-108?

A. That's correct.

Q. There again, figuring in no collars?

A. That's correct.

Q. And a 25 percent access?

A. That's correct.

Q. Now I'm going to refer to Exhibit No. 22 and do somewhat of some kind of comparison work here to Exhibit 15.

Now, when I show your incremental oil, referring to Exhibit No. 22, this is the oil which we expect to recover with the waterflood, the 1.4 million barrels, is that correct?

A. That's correct.

Q. Now, I could not find an Exhibit No. 15, but is it different when I find that information in here, or is it even presented in your Exhibit 15?

A. No. Exhibit 15 are just going to be the results of the production coming out of the computer modeling work. I guess I should ask a follow-up to your question. It has all of the production coming out of the unit area during the flood operations. In other words, it has both the primary plus the secondary, is their prediction. Is that the answer you're looking for?

Q. I believe it is. There was a reference in your summary. Reservoir depletion was estimated to be 1.86 million standard stock tank barrels.

A. Stock tank barrels, yes.
Q. Is this figure utilized throughout, or am I going to see different reservoir figures?
A. No. The 1.4 and the 473,000 barrels of oil, adding up to this 1.8 you're referring to, is taking Petresim's computer simulation numbers and applying Mewbourne Oil Company economic evaluation to those predictions.
So Exhibit 22, the incremental oil is based on economic parameters, not just computer modeling that Petresim did in Exhibit 15.
Q. I hate to belabor this, but when I look at your Exhibit 19, I show 15 injection wells.
A. That's correct.
Q. Is that 13 new ones, or 13 conversions plus your two, or are you going to have a total of 17?
A. No, you have it correct. It's two existing and 13 will be converted, for a total of 15.
Q. And those are all conversion Bone Spring completions?
A. That's correct.
Q. You testified that the average well produces seven barrels of oil at this point, is

that correct?

A. That's correct.

Q. What's the high side? What's one of your best producers out there?

A. Probably 15 barrels per day. In other words there were some wells that didn't quite meet the BLM's Schedule B royalty reductions, and their cap is 15 barrels per day, so I'll offer up 15 barrels a day as a high side.

Q. How about your low side?

A. There are some wells that are shut in, currently.

Q. What's economic producers out there?

A. Three barrels per day.

Q. Do you have some of those?

A. Well, you know, I say three barrels per day. Please understand, that's depending on the gas rates out of the well, et cetera, et cetera.

Q. To come up with seven barrels of oil a day, did you include those ones that are shut in?

A. Yes, I did. Basically, all the wells in the unit area currently make 230 barrels per day total, and I divided that by the 32 wells that are being unitized.

Q. Now, if I remember right, there were 35

completion attempts?
A. Yes, sir.
Q. And 32 producing wells?
A. Currently producing. Yes, sir.
Q. Now, are those actually producing or are some of them shut in?
A. Well, true. Some of them are shut in. Those are wells that currently have perforations open to the First Bone Spring sand.
Q. Do you know how many actually are pumping and actually making oil?
A. Well, 32, minus the two test injectors is 30, minus the Sprinkle No. 2.
Q. Just a rough estimate, how many shut-in wells have you got?
A. Let's say 29.
MR. STOVALL: 29 shut in, or 29 active?
THE WITNESS: 29 active.
Q. If I look at that average production on those 25 active wells, would that fall under 10 barrels of oil per day. Okay. The 29 active wells--
A. --divided into the 230 days, would be less than 10 barrels a day, yes.

Q. So we're definitely talking stripper wells?

A. Yes.

EXAMINER STOGNER: We will take administrative notice of Order No. R-9737 and the previous case that resulted in that order, and with that, I have no other questions of this witness at this time.

MR. STOVALL: Well, I do.

EXAMINATION

BY MR. STOVALL:

Q. I think your application states you are asking for the EOR tax credit?

A. That's correct.

Q. Other than your injectivity test this is a new project, is that correct?

A. That's correct.

Q. I note, in looking at your various maps, there are some undeveloped proration units within the pool. Have those been determined to be just not productive or no oil in place within the unit area?

A. Can you be a little more specific?

Q. I'm looking at Exhibit 19. I'm looking at Exhibit 19, specifically, because it has the injectors, but Section 27, Section 28--

A. Right.

Q. --they look pretty well developed within the interior pool. Are most of the undeveloped tracts on the exterior of the pool?

A. A couple of things are happening with that area of the pool. One is, there's not a lot of mapping points over there, and we don't know how much deposition occurred over there. We don't know how much net height to give that area.

Obviously, the owners of those tracts were not interested in those tracts for the primary reserves alone, and did not drill a well for the primary reserves.

However, we, and of course all the participants in the unit, and the BLM, believe that there might be justification to drill a well for the primary plus the secondary reserves of those tracts. We plan on developing those tracts as soon as the waterflood has proven itself to be successful.

Q. Is the potential primary in there calculating 400-and-some-thousand primary?

A. No, sir.

Q. It's not included? It's only in the developed?

A. That's correct.

Q. How familiar are you with the EOR tax credit provision or rate reduction?

A. Oh, vaguely familiar. I'm familiar with the rates, not familiar with the paperwork to apply for it.

Q. This is it. You're in it.

A. Okay.

Q. I will explain it briefly to you, that what has to happen is that this is a new project. The approval of a project after the date can qualify the project, it meets the basic criteria for qualification. That does not mean you get the tax rate, that means we can certify it as a qualified EOR project.

You would not be eligible for the tax rate until such time as there is a production--what's the word?

MR. BRUCE: Production response.

Q. Positive production response. Thank you, Mr. Bruce. When do you plan to actually start waterflood operations?

A. We'll put the unit into effect the

first of the month, after we receive the Division order.

Q. I mean actual water. I don't care about the unit.

A. We're going to start water into those two test injectors as soon as we receive the division order.

Q. Now, you've already put some water in those, is that correct?

A. That's correct.

Q. And have you had any response from that?

A. No, we haven't. Not yet. Those will just to test the injectivity.

Q. Which wells are those? Well, where are those wells located? I'm looking at Exhibit 19, because it kind of gives me an aerial.

A. It's Section 23, Proration Unit K, and Section 27, Proration Unit A.

Q. How long is it going to take to construct and convert the rest of the unit?

A. To get full flood up and running, it would take approximately three months, I would estimate.

Q. From the dates the project is

certified, because this is a secondary project, you would have five years to get a positive production response. I'm kind of gathering, from what you're saying, that three months isn't going to be a big deal or make it or break it?

A. No. No, sir.

Q. So, we could certify the project at the time as of the date that the order is entered approving the project?

A. Yeah.

Q. Now, actually, that five years is not to get the response, but is to apply for a certification of positive production. You may get it in a year, but if you don't apply to us within the five years, you lose the credit regardless of when you got the response.

You're not talking about phase development of this project, is that correct? You're going to start converting and keep on moving?

A. Uh-huh.

Q. What we will do at the time we approve it would be to certify the area, and it would seem to me appropriate to certify the unit area at that time.

How long do you anticipate it will take to get your Phase I out onto the unit agreement?

A. Our estimates are three and a half years right now, about 470,000 barrels.

Q. But you do anticipate there will be an increased production rate during that period?

A. Yes.

Q. And that's simply for accounting purpose, not for a recovery purpose?

A. Right.

Q. At the time we certify the area, as I say, I think we can certify the entire unit area. The question I'll have, at the time you come in with a positive production response, it is very likely that the Division will look closely at where you are actually injecting and appear to be receiving a benefit.

Now, what you're going to have to do is come in and demonstrate, and I think in this case, be prepared to show which wells have benefited from the response, by use of production curves. I assume you have curves on most of the wells, is that correct?

A. Yes, sir, we do on all of them, yes.

Q. So, you could come in and say which

wells are receiving it. What I'm particularly concerned with in this case is in those tracts that are undeveloped, in which you may drill.

It may be that initially, when you get the positive production, those areas will be excluded, because there is some primary recovery that's going to occur first, before you get a secondary response.

A. Okay.

Q. Is that making sense? I'm not telling you what will happen but I'm telling you things I think we'll need to look at.

A. And be prepared to address those issues?

Q. Be prepared to address those, because if you've got areas within the project which have not had any primary production at all, and then you go and develop them subsequent to the certification of your project, I think we may, as I say, constrict the actual area which is qualified for the rate, at the time you get the positive production response, to those areas that have shown a true positive responses over an established primary decline rate.

A. Okay.

Q. And those areas, again, Section 28, 27. Those look like the biggest ones; maybe 13, where you don't have an established primary there and, as I say, they may not be included in the project area, because the rate applies to all production, not just to incremental production.

A. Okay. But you have to show a response?

Q. But you have to show a response. The objective is to give you the credit, really, for the incremental oil you're going to be recovering, but do it by way of giving you half a tax rate on all of the oil rather than having to calculate some incremental number.

That is an issue that we will want to look at when you come in for your positive production response hearing. I guess what that means, if you want to qualify those areas early, you may want to think about early development of those areas so you can get an established decline rate and then show a response.

That's obviously a management question. Either that, or you go ahead and develop them later and come back in for an expansion into those areas, when you expand the flood into those areas. If that's the case, that you go and drill and get primary, then you can come back when you're ready to expand, and get a secondary and expand the response area. And we'll get you the credit at that time.

A. Okay.

Q. That's pretty much the process. Five years from the date that the order is going to be entered will be your magic date. If you don't get us an application in by that date, you will not receive the credit regardless of how good a job you did.

A. I'm sure we'll apply for that as soon as possible.

Q. Also, the effective date of the credit is to the date of the positive production response. So, what we've encouraged operators to do is to make sure it is truly a positive production response and not just a burp in the production, because you're taking better care of the wells and putting new equipment on them.

A. Seeing gas flaps gallons and some other--

A. Right.

Q. It doesn't hurt you to wait six months to make sure it's a valid response and then come back in, because the credit will go back to the date we determine is a response date. You will not lose that value for that period.

A. Okay.

Q. I think that's all I have, unless you have any further questions about the process?

A. No. I think we can accommodate that.

MR. CALVERT: May I ask a question?

EXAMINER STOGNER: For the record, why don't you identify yourself, and then ask.

MR. CALVERT: All right. My name is Ken Calvert. I'm employed by Mewbourne Oil Company as manager of secondary recovery, and I have a question, not of anything that we've talked about here, but do you have, Mr. Stovall, an explicit one, two, three, four application for the tax abatement, other than what you have verbally told us?

MR. STOVALL: We do not. You have done the first process here of getting the project approved. You have completed Step 1. Step 2 is to implement the project and get a positive production response. And the burden is on you to come back and say, "We've received a positive production response. Please certify that response to Taxation and Revenue," at which time we would say, "Which wells and what lands?"

But the burden is on you to come back in and demonstrate it and show us how that's happening. And, no, we do not have a one, two, three, four cookbook process. We haven't had a positive production response yet. We've had several cases for the certification of a project, but no positive production responses yet since it's only been in effect since March.

MR. MAYES: Can I ask a follow-up to that? So, do you apply, when you apply for the application after receiving the response, do you do that on a tract-by-tract basis?

MR. STOVALL: No. Again, in this case, the entire unit area will be certified as the project area. You'll apply for a positive production response, and, at that time, demonstrate which wells within that project area are actually benefiting from the waterflood and showing a response.

Again, for example, using Section 27, you have an injector out in the, looks like, Unit G of 27, and if those offsetting producing wells didn't show a response, that might be excluded from a project area even though you've got injection going on.

With enhanced recovery, if you're not actually getting a response from the producers in the pattern, it could conceivably be excluded from the response area and might not get the credit until you get the response in. Does that answer your question?

MR. MAYES: I guess what I have trouble understanding, the revenues are distributed to the wells on a tract-by-tract basis. How would you tax abate one well without another well in the same tract?

MR. STOVALL: That's something you might want to address when you come back in for a the response. Each time we do it, a new question comes up. Good question. That's a consideration, too.

MR. MAYES: I'll follow that one up a little bit.

MR. STOVALL: It may be, is your tax rate going to be part of your participation formula? Even though one well qualified for the tax rate and the other didn't, that tract would still share in the revenue, on the basis of the tract participation, without regard to the--because the credit is a reduction of expense, it's not a positive production share. It's not a production share, it's a reduction of expense over the unit.

MR. MAYES: Sounds like a question to ask the accountants.

MR. CALVERT: Mr. Stovall, may I make a statement concerning that? Typically, a lot of units are put together where the royalty owner, all tracts are so-called unitized, and the participation, royalty, and everything, everybody has one number for the entire unit, okay?

MR. STOVALL: Okay.

MR. CALVERT: We have found, in dealing with some other large units, that it is very cumbersome to deal with, and what you have just said, it would be almost impossible to have one number for everybody, because that one number might have different taxes.

In other words, for instance, if, say, Tract 5--or any of them--but a person had interest in Tract 5 and had an interest in Tract 2, those wouldn't be taxed at a different rate. And, in other words, if 5 got abatement and 2 didn't, but you had to credit a royalty owner or a working interest owner with that amount, that would be very difficult to track.

So, from what you're saying, our tracking by tract and maintaining tracts separate throughout the unit, will probably be the easiest way to handle that.

MR. STOVALL: Well, my suggestion to you is, and again you'll have to talk to your accountants about that because that's an accounting problem, not a recovery problem--

MR. CALVERT: True.

MR. STOVALL: --is that regardless of which portions of the unit qualify for the credit, if you're applying the rate, the rate's going to be on total production from the unit, except for those portions of the unit which do not qualify.

It may be that you just simply don't discriminate--those tracts may get the benefit of the credit even though those wells have not specifically shown a positive production response, and the production from those specific wells, if you're not getting a positive production response, the tax rate on three to seven barrels a day is not going to make or break any tract.

That's really the key issue there. I wouldn't spend a whole lot of accounting money. I don't think it changes your accounting, it simply just changes the number in the cost column. I don't see why you would have to separate the way you account to the owners in a tract which did not receive the EOR tax rate.

My guess would be that just simplicity would dictate that you treat them the same, regardless, because they've shared in the cost and they've contributed to the rent. It is simply a--the only people it will effect are the overall costs to you and the revenue to the state.

At the time that it actually comes up, we may have to relook at it. I think it's a valid question.

EXAMINER STOGNER: Anything further in either of these cases at this time?

If not, then, Case Nos. 10761 and 10762 will be taken under advisement.

Let's take a 10-minute recess.

(And the proceedings concluded.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case Nos. 10761 and 10762 heard by me on 1 July 1993.

, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL July 21, 1993.

Carla Diane Rodriguez

CARLA DIANE RODRIGUEZ, RPR
CCR No. 4