NEW MEXICO OIL CONSERVATION COMMISSION

STATE LAND OFFICE BUILDING

STATE OF NEW MEXICO

CASE NO. 10771

IN THE MATTER OF:

The Application of OXY USA, Inc., to Authorize the Expansion of a Portion of its Skelly Penrose "B" Unit Waterflood Project and Qualify Said Expansion for the Recovered Oil Tax Rate Pursuant to the "New Mexico Enhanced Oil Recovery Act," Lea County, New Mexico.

BEFORE:

CHAIRMAN WILLIAM LEMAY

COMMISSIONER BILL WEISS

COMMISSIONER GARY CARLSON

State Land Office Building

Morgan Hall

February 10, 1994

REPORTED BY:

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

MAR 3 1994

ORIGINAL

A P P E A R A N C E S

FOR THE NEW MEXICO OIL CONSERVATION COMMISSION:

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

FOR THE APPLICANT:

KELLAHIN & KELLAHIN
Post Office Box 2265
Santa Fe, New Mexico 87504-2265
BY: **W. THOMAS KELLAHIN, ESQ.**

I N D E X

E X H I B I T S

CHAIRMAN LEMAY: At this time we'll call Case 10771.

MR. STOVALL: This is the application of OXY USA, Inc., to authorize the expansion of a portion of its Skelly Penrose "B" Unit waterflood project, and qualify said expansion for the recovered oil tax rate, pursuant to the New Mexico Enhanced Oil Recovery Act, Lea County, New Mexico.

CHAIRMAN LEMAY: Appearances in the case.

MR. KELLAHIN: May it please the Commission, I'm Tom Kellahin, of the Santa Fe law firm Kellahin & Kellahin, appearing on behalf of the Applicant, and I have three witnesses to be sworn.

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

Those witnesses who will be giving testimony, please stand and raise your right hands to be sworn in.

[And the witnesses were duly sworn.]

CHAIRMAN LEMAY: Mr. Kellahin, you may proceed.

MR. KELLAHIN: My first witness today

is Scott Gengler, and while Mr. Gengler finds his way to the witness stand, I'll pass out the exhibit package.

We're before you today to request that the Commission modify the Division order that was entered approving Oxy's waterflood project and providing an enhanced oil recovery tax credit for what they've identified as their Skelly Penrose "B" Unit waterflood project.

I have three witnesses for you today. Mr. Gengler is the project reservoir engineer, and he is going to describe for you what, in his engineering opinion, is a significant change in process. That process involves taking an old waterflood project that was developed and depleted on an 80-acre inverted five-spot pattern. His change in process involves reducing that pattern to a 40-acre pattern.

That is a process that Mr. Gengler has concluded is a significant change which would qualify this project for the enhanced oil recovery tax credit.

The Division Examiner, Mr. Catanach, has agreed with Mr. Gengler, and so the reduction in pattern for Oxy, as well as other projects approved after this one, has been recognized by the Division as a significant change.

The issue of concern for us is that Examiner Catanach provided a limitation in our approval that is unique unto this order, and has not been applied to any other projects like this since our order.

Briefly, the project area involves some existing producing wells. The change of pattern was such that there are five existing infill producers, and there are five more yet to be drilled.

Mr. Catanach has excluded from the credit the producing wells that were already drilled, allowing the project area to contain only those five producing wells that had not yet been drilled. That order, we contend, provides a test for qualification that is neither in the Division rule nor in the Enhanced Oil Recovery Act.

So, first of all, Mr. Gengler is here to tell you what his project is about. The second witness is Mr. Foppiano, who is also a reservoir engineer but, more important to this case, is a regulatory expert for his company.

From his engineering perspective, then, we have provided him copies of all similar transcripts, exhibits, and orders for cases like this processed by the Division, and he will demonstrate for you that other projects, with the exception of ours, that have been approved since the Oxy application, have not contained this type of limitation.

And then finally, Mr. Carr is our legal expert, who we have asked to testify with regards to the legislative history, the purpose of the EOR Act, and to render his legal opinions concerning certain topics of concern with regards to the specifics of this case.

The package of documents before you contain the prehearing statement. I have written out for you the statement of the case that I've just described. There is a second page that says the relief requested, and I have identified for you the three specific issues we're asking you to deal with this morning, and then a list of the witnesses and a quick summary of what we think they will testify to.

After the prehearing statement, there is contained in the package, for your reference, the Oxy order that is in question this morning. Followed after that is a copy of Division Order R-9708, and those are the rules and regulations adopted by the Commission with regards to the enhanced oil recovery procedure, and qualifying a project for approval, and then the subsequent provisions with regard to certification of those projects.

To point you in the right direction, if you'll take Commission Order R-9708, turn to page 2 of Exhibit A, Exhibit A is the actual rules, turn to page 2 of the rules and look up at the top and find numbered paragraph 4. It says, "Expansion or Expanded Use." It is that paragraph that we are dealing with.

And then, after that, we have included the rest of the hearing exhibits for the various witnesses. Included in the package are going to be copies of other similar action taken by the Division, where we will point out to you what we consider to be the inconsistent treatment of this particular case by the Division.

We are not here in a matter of dispute or contention with the Hearing Examiner. Quite frankly, he has encouraged us to come before you to provide him with direction and guidance on how to interpret the Act. This is incredibly complicated and a tedious process, and I have met with Mr. Catanach so that I understood what it is that he was trying to write in the orders.

So, we're not here to criticize his work. We believe this is a difficult process. What we're here to tell you is that, since the Oxy case, I think the Division has come to a different understanding and conclusion about how to handle drilled wells within a project area, and has subsequently not made this requirement on others, and we believe it's necessary to change this order so that we receive consistent treatment.

Having said that, we're ready to present Mr. Gengler.

SCOTT GENGLER

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

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Scott Gengler. That's

spelled G-E-N-G-L-E-R, and I'm a petroleum engineer.

Q. Mr. Gengler, the microphone in this hearing room does not amplify your voice. It's just for the court reporter's recording equipment. You have to speak up so we can all hear you.

A. All right.

Q. Describe for us, sir, what has been your involvement in what has been identified as the Skelly Penrose "B" Unit waterflood project that is currently operated by your company?

A. My involvement was to undertake a study to look at the feasibility of converting this old 80-acre five-spot waterflood into a 40-acre five-spot waterflood to increase the recovery out of this unit.

Q. Did you undertake that study?

A. Yes, I did.

Q. Did you have sufficient engineering data and information by which to make that study?

A. Yes, I did.

Q. Based upon that information, were you able to reach conclusions, as a reservoir engineer, with regards to the feasibility of establishing a waterflood project for this area on 40-acre inverted pattern?

A. Yes, I did.

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

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. Mr. Gengler, I think it will help us, sir, if you turn in the package of exhibits to what has been marked as Oxy Exhibit No. 1 to this hearing. There's also a larger copy of this plat. On the display board, it is the first display on the left, as the Commission looks at the display board.

First of all, describe for us what we're looking at in Exhibit No. 1.

A. This is the Skelly Penrose "B" Unit, which is located six miles south of Eunice. It contains approximately 2,600 acres, and this map depicts the 80-acre five-spot waterflood pattern that was in existence when we took over operations of this unit.

Q. Describe for us what has been the history of the initial primary development, and then the first waterflood attempt in this unit.

A. The first well in this unit was drilled in 1933, with subsequent wells drilled thereafter. The unit was unitized in 1965, with waterflood operations beginning in 1966.

Oil production was realized in 1971 at 500 barrels a day, and began declining from there. By the 1980s, the waterflood was becoming depleted, had a high water cut. Makeup water was ceased in 1984 and, after 1984, basically, the project had become a disposal project.

Q. Who was the original unit operator?

A. The original unit operator was Getty Oil.

Q. Were there any other intermediate operators, between Getty's operation and the point in time when Oxy purchased the unit?

A. Yes. Texaco bought Getty Oil out in 1984 and became the operator in 1985. In 1987, they sold the unit to Sirgo Operating, and in 1993, Oxy bought the unit from Sirgo Operating.

Q. At the time Oxy acquired the unit, summarize for us the status of the property.

A. The property was pretty much depleted. Oil production was 22 barrels a day. We had one active injection well. The waterflood facilities and equipment were pretty well gone. Most of it was either in disrepair or had been robbed or taken away to some other place. Basically, it was on its last legs.

Q. What's the date of acquisition by Oxy?

A. February 1st of 93.

Q. The topic of the hearing today is the certain infill wells that were drilled as producing wells, within what we've identified as the project area?

A. That's correct.

Q. Were there any of the project producing wells, that we sought to include in our project area, that had been drilled prior to the time of Oxy's acquisition of the property?

A. Yes, there were five wells within the project area that had been drilled in 1988.

Q. Based upon your study of the history of the project, what was the purpose of that operator, in drilling those wells?

A. The purpose of drilling those wells by that operator, which I obtained from visits and talks with him, basically was that they were looking for some mobile oil saturations within the waterflood pattern that had kind of banked up and not been recovered.

They had undertaken this in another Queen waterflood, the West Dollar Hyde Queen Unit that they operated, and had found several areas where they had banked up oil, getting upwards of 200, 250 barrels a day initially out of these wells.

They were trying to locate those in this unit, drill these five wells, weren't satisfied with the results, and basically left it at that.

Q. Describe for me what Oxy undertook, then, when it acquired the property, to make a decision on what to do with this property?

A. The previous operator had commissioned a consulting reservoir engineer in Midland, Texas, T. Scott Hickman, to do a study on this project, prior to the drilling of these 1988 wells.

Based on his study, and a study that we conducted on our own, we felt like there was opportunity to reduce the spacing on this particular unit due to four vertical and aerial sweep efficiencies found in the waterflood. This is basically due to a reservoir that was slightly discontinuous, with some permeability and porosity pinchouts, and felt like that there was inadequate sweep that was going on on the 80-acre five-spot.

Q. Let's turn to Exhibit No. 2 now, Mr. Gengler. Identify and describe for us the production plot we're looking at here.

A. This is a production plot of the Skelly Penrose "B" Unit. As you can see, in 1966, water injection began. It started getting a small response in 1967, and peaked about 1971 at 500 barrels a day.

It was on a steady decline until 1984, when the operator at that time decided that the economics of the project were no longer there, and decided to cut the makeup water.

Q. When we look at the point in time between 84 and 85, and you're looking at the water injection rate, it looks like water injection significantly is reduced about that time frame?

A. That is correct.

Q. The operator, then, is no longer injecting, into the flood, makeup water?

A. That is correct.

Q. What are they injecting?

A. They are just injecting the produced water that they're producing from their wells.

Q. And it continues in that form of operation until when?

A. Until the present time. And that's depicted by the fact that the water injection curve and the water produced curve are basically sitting on top of each other.

Q. Okay. Let's turn now to Exhibit No. 3. You made reference to a previous engineering report. What is Exhibit No. 3?

A. Exhibit No. 3 is the reservoir study done by T. Scott Hickman, or consulting reservoir engineer, for the previous operator, done in 1987.

Q. What were the Hickman engineers' conclusions, with regards to this particular project?

A. If you turn in the report to the sixth page back, into the conclusions, No. 3, "Under current mode of operations, the Penrose "B" Unit is in the latter stages of depletion," No. 6, "Oil recovery has varied greatly across the field due to variations in completion techniques, reservoir heterogeneity, and water injections inefficiencies."

And he basically concluded that the feasibility of the 40-acre five-spot waterflood project had a high probability of being successful, that there was mobile oil saturation there, and because of the heterogeneity in the reservoir and the poor sweep efficiencies, that there was additional oil that could be recovered from the project area.

Q. Having reviewed that report and analyzed it, in terms of the other information you have about this project, do you agree or disagree with that conclusion?

A. I agree with that conclusion.

Q. Let's turn now to the specific five wells that were--the five or six wells that were drilled in 88. Five of those six are within what we proposed to be our project area when we filed this application before the Division?

A. That is correct.

Q. Let's turn now to Exhibit No. 4 and have you identify and describe that.

A. No. 4 is a decline curve of the five infill wells that were drilled in 1988 in the project area.

As can be seen by the decline curve, initially they came in approximately 15 to 25 barrels a day each, but they dropped off very quickly. We believe this is due to lack of reservoir pressure in the reservoir, and some banked up oil from the 80-acre five-spot waterflood was banked up in this area, and this is the flush production you're seeing from it.

The flood leveled out, economics started getting bad for the unit, and in 1992, Sirgo shut in three of the wells and removed the equipment from them.

In 1993, Oxy came in, did a lot of work on the unit, including reactivating the three wells that were temporarily abandoned, and saw some increase back to approximately the level they were when they were shut in.

In addition, they worked over one additional well late in 1993 that was successful, which increased production to the 35 barrel range, but it quickly dropped off, also, as there was some flush production in there.

Q. Have you made engineering estimates of what, in your opinion, is the estimated reserves that these five infill wells will ultimately produce?

A. Yes, I have.

Q. Let's turn to Exhibit No. 5 and have you identify and describe that.

A. This is a decline curve analysis on the five infill wells and reserve estimates for these wells in the project area.

Currently, the five wells are making 29-1/2 barrels of oil per day. Using an economic limit of two barrels of oil per day per well, we determined that the remaining reserves from decline curve analysis are 42,000 barrels.

Q. Do you have a tabulation of what the current rates are on those wells?

A. Yes, I do.

Q. Is that shown on Exhibit 6?

A. Yes, it is.

Q. Let's look at that now.

A. The five wells are listed there. Most of them are making between four and six barrels a day. Well No. 66 is currently producing 11 barrels per day, and that was the well that we worked over. We tried the same workover techniques on two of the other wells, but were unsuccessful.

Q. Having examined the information about those five infill wells, and the relationship of those to the old 80-acre five-spot waterflood pattern, do you have an opinion as to whether or not any of those five wells ever saw a positive production response as a result of the 80-acre flood?

A. No, I don't think that they really have. Based upon the decline curve analysis in Exhibit 5, we concluded that ultimate reserves for the five wells were approximately 99,000 barrels of oil or approximately 20,000 barrels per well, which is slightly below the average primary production for each of the wells in the unit, prior to unitization.

Q. Having undertaken the study of the project as you required it, what have you determined is the appropriate means for establishing a secondary recovery project to go get the secondary oil potential out of the property?

A. We feel like that going to a 40-acre five-spot will increase our sweep efficiencies. This is mainly due to how the reservoir is laid out with the permeability variations and discontinuous portions of the individual sands. The Penrose in this area contains 11 different sands, and the permeability variations and porosity variations differ quite readily in between wells.

So, we feel like by down-spacing into a smaller pattern, on a five-spot, we will contact additional areas that have not been swept.

Q. Do you have an opinion as to whether or not this change in process represents a significant change in process, or technology, that will result in the more efficient sweep of this area of the unit?

A. Yes, I do.

Q. What is that opinion?

A. I believe that it is a significant change in process because areas that were not swept before, which is evident by the five infill wells that were drilled in 1988, have not been swept, there is no pressure in the reservoir at that point, and we feel like by decreasing it, we're changing the process and contacting new area that had not been contacted by the 80-acre flood.

Q. Is this simply a logical continuation of an existing waterflood project?

A. No, it's not. The infill wells were not really a continuation of a waterflood project. An 80-acre project was really a separate deal, it was not really flooding all the area of the unit, so we feel like it's not a continuation, it's a new waterflood; especially when you consider the status of the unit, with one injection well active and the unit making 22 barrels a day.

Q. Have you made a literature search to see if there's other technical references that support your conclusions about the feasibility of taking an old waterflood project and reducing the pattern?

A. Yes, I have.

Q. Do you have an example of that type of reference material for us to look at today?

A. Yes, sir, it's Exhibit No. 7.

Q. What are we looking at?

A. This is a Society of Petroleum Engineers paper written by T. Scott Hickman and C. D. Hunter of the T. Scott Hickman & Associates consulting firm, the title of which is the redevelopment of depleted Queen waterflood projects in the Permian Basin.

This paper looks at several Queen waterflood projects in the Permian Basin, and the feasibility of going to a 40-acre five-spot waterflood, basically due to the same principles that we're talking about here in the Penrose "B".

Mr. Hickman did a study of which the Penrose "B" was one of the units that he looked at and determined that, by improved oil recovery techniques, that additional oil could be recovered. These improved oil recovery techniques were the down-spacing of the waterflood project from an 80-acre five-spot to a 40-acre five-spot, to greatly enhance the sweep efficiencies in the reservoir.

In his study, on page No. 2, he states, "The authors have evaluated over a dozen of these depleted Queen waterfloods for improved oil recovery potential in recent years. The term redevelopment has been applied to the process of exploiting the potential of these depleted floods since both infill drilling and the reestablishment of full scale water injection is involved."

On the next page, at the bottom of the left-hand side he states, "The primary and secondary development techniques utilized in the Queen reflected prevailing concepts which have since been rendered obsolete by engineering and geological advances."

Q. And the primary and secondary development techniques he's talking about in the Queen, have been the old technique of an 80-acre pattern?

A. Right. The prevailing concept back in the 60s and 70s was that you basically had a homogeneous reservoir that was very continuous. They had old logs with no cores available to them, and they felt like all these sands were continuous across the unit.

And they used the prevailing knowledge that every waterflood, for every primary barrel you produce, you can produce a secondary barrel in addition. This unit was performing right on that schedule, so they basically felt like this was adequate waterflood.

But, due to advances in engineering and geological studies and the infill drilling of these wells, we found that this sweep efficiency wasn't nearly as good as what they had anticipated.

Q. Does the infill drilling of these prior producers in and of itself constitute the execution of a plan that would be a significant change in process to get the additional secondary oil?

A. No, it does not. As I read on page 2, where he said that these depleted floods both need infill drilling and the reestablishment of full scale water injection, really states the obvious in this fact that the water injection is really the key to this development of this sweep efficiency without any water injection.

As you can see, we're not going to get anywhere near, you know, recoveries of oil that would be needed to have a project, just by infill drilling.

Q. Let's turn now, Mr. Gengler to Exhibit 8, and have you identify and describe for us how you're going to institute this plan to reduce the pattern to a 40-acre inverted five spot.

There's a larger copy of this same display on the display board. It's the exhibit on the right.

A. This is, again, an outline of the unit, and the shaded areas are the project area. The black triangle wells are current injection wells under the 80-acre five-spot; the inverted blue triangles are the wells that we're producing that we're going to convert to injection; the wells in green are the ones that were drilled in 1988; and the red wells were the ones that we were proposing to drill to fill out the patterns.

Q. The order, as issued by the Division in your case, approved the project area that's described on this display in the yellow shading, is it not?

A. That's correct.

Q. And then, in a subsequent sentence, identified only five wells as being wells that would qualify eventually for having their production eligible for the reduced severance tax credit?

A. That is correct.

Q. Which of the five wells on this display are those wells for which the Division has authorized the credit?

A. The five wells in red, the ones that we had proposed to drill.

Q. The other five wells are the ones that are shown in the green dots?

A. That is correct.

Q. Those are the ones that would be the producing wells, when you reduce the pattern to a 40-acre inverted five-spot?

A. Correct.

Q. Let's talk about sweep efficiencies. Let's turn to your display marked Exhibit 9. If you'll take the overlay and fold it back and look at the white page, describe for us what you're trying to illustrate with the pattern identified as the 80-acre five-spot waterflood pattern.

A. Basically, what we're showing are the flow paths of the water as it leaves the injection wells to the producing wells, in a very simplified manner. What we're showing are the channels as it goes from the injection wells to the producers, and what kind of sweep that we're anticipating out of the 80-acre five-spot.

Q. If you take the overlay and put it over the 80-acre pattern now, what are you illustrating with the red lines?

A. We're illustrating going to a 40-acre five-spot pattern, where we drill an infill well in between four wells, convert the two old producers to injection, and establish new injection lines in between the injectors and the producers.

Q. Does that change in process allow you to contact reservoir and to sweep that reservoir that had not previously been contacted with the 80-acre flood pattern?

A. Yes, it does. As you can see, we feel like we're not overlapping our injection between our injection wells, and that there's areas in the middle that have not been contacted.

This was backed up by the infill drilling of the five wells, which showed no pressure response or secondary response to the 80-acre five-spot.

Q. Will that sweep efficiency, resulting from the change of pattern, apply to those patterns contained within the area shown for the new producers?

A. Yes.

Q. Will it also apply to the changes of sweep efficiency for those patterns that contain oil wells that are already drilled?

A. Yes, it will.

Q. Is there any difference between the two?

A. No, other than the fact that the wells drilled in 1988 have depleted the bulk of the residual oil around the wellbore.

Q. Have you made a determination whether the change in process is going to result in the opportunity to recover significant additional oil from the project area?

A. Yes, I have.

Q. Have you reduced that information to a display?

A. Yes, I have.

Q. Is that Exhibit 10?

A. Yes, it is.

Q. Describe that for us.

A. Exhibit No. 10 is our reserve estimates based on volumetrics. And, based on our volumetric estimations for the reservoir, we feel like with a sweep efficiency of 65 percent, which is basically what we feel like a 40-acre five-spot pattern would recover, there are approximately 972,000 barrels of recoverable oil in a 40-acre five-spot waterflood pattern in the project area.

Q. Let's turn now to Exhibit 11 and have you identify for us the development costs that are assigned to the project in order to have the opportunity to recover that additional oil.

A. Exhibit 11 is an illustration of the costs that we have incurred to date on our project. The project has pretty much been finished, and these are the latest estimates.

To put in this waterflood on a 40-acre pattern, we spent approximately 2.7 million dollars on the project area.

Q. In addition to the expenditure of these resources, were there other moneys spent on the property in order to put it back in operational function?

A. Yes. We spent $2 million to go in there and, what we considered, clean up the unit. There were a lot of temporarily abandoned injection wells that had tubing that was leaking. Some of them had casing leaks. We went in to every wellbore on the unit, including those outside the project area, pulled all the wells, set cast-iron bridge plugs, tested the casing, and run a mechanical integrity test on every well.

Q. What does the tax credit do, as an incentive for you and your company with regards to this project?

A. What the tax incentive does, it helps the economics of this project out. Although the project is an economic project, just like any other company, it is put into a battle with any other project for funds. What this tax incentive does, it would allow us to higher prioritize this project, compared to other projects that we have available to us, for the competition for funds.

Q. Summarize for us your conclusions about the project, Mr. Gengler.

A. In conclusion, I feel like the 80-acre five-spot waterflood pattern was inefficient, due to poor vertical and aerial sweep efficiencies, that there is approximately a million barrels of oil to be recovered out of the project area by going to a 40-acre five-spot.

I feel like that even though the infill wells were drilled in 1988, that really no waterflood response or recoveries were associated with these wells. The conversion of the wells to injection and commencement of injection into all the wells in the project area, is really the driving mechanism behind the recovery of this million barrels of oil. And we feel like the 40-acre five-spot will increase the sweep efficiencies, and allow us to recover this million barrels of oil.

Q. When we look at the display that shows the property after the change in operation, Exhibit No. 8, describe for us your basis for identifying that as your project area.

A. We looked at, on a reservoir study, the entire unit, based on structure and isopach maps and geological parameters, and we decided that the best place to start would be the best part of the unit. The project area that we chose had the best quality of pay, it had the best primary response, and the best secondary response under the 80-acre five spot.

This area, with slight modifications, was the same area that Mr. Hickman recommended in his study.

Q. In your opinion, is that project area the area that should qualify for the enhanced oil recovery severance tax reduction?

A. Yes, it is.

Q. Will the reduction that is attained from that area be in response to a reduction in the pattern?

A. Yes, it is.

Q. Is there additional remaining primarily production yet to be achieved in that project area?

A. There is a small amount of primary and/or secondary under an 80-acre that could be recovered. The five wells we estimated at 42,000 barrels. The other wells wells had probably another 20-, 25,000 that they might recover. It was a small amount. The bulk of our reserves at 972,000 barrels, is going to be due to the injection on the 40-acre five-spot.

Q. Is that secondary oil production, could that be recovered if you simply reinstituted water injection on the 80-acre pattern?

A. No.

MR. KELLAHIN: That concludes my examination of Mr. Gengler. We would move the introduction of his Exhibits 1 through 11.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 11 will be admitted into the record.

Questions of the witness? Commissioner Carlson.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. You said that the first wells in the unit were drilled in 1933?

A. That is correct.

Q. And you acquired it in 1993?

A. That is correct.

Q. And at that time it was producing 22 barrels a day?

A. That is correct.

COMMISSIONER CARLSON: Why don't you all go on.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Was the full expansion in yellow there presented to the Examiner?

A. Yes, it was.

Q. At that time, did you request the entire area be subject to the reduction in the tax?

A. Yes, I did.

Q. What does today's price do to this

project?

A. It makes it very marginal.

Q. Have you already done the work?

A. Yes, we have done the work since the order was written.

Q. So you don't have more money to spend, you've already spent it, is that the point?

A. That's correct.

Q. Might not get it back, huh?

A. Well, it depends on what oil prices do.

Q. Then, on your rate graphs, any of them there, just a question of clarification. What does "CD" mean?

A. Calendar day. That's oil rate per calendar day.

Q. Okay. I didn't know what "CD" was. On "Exhibit 7" in Exhibit 3, you've got the history of the unit, of the area.

A. Okay.

Q. What was waterflood fill-up there as a percent of primary? Did you figure that out, in your investigation?

A. No, I didn't.

Q. And then, on one of the other exhibits, you had a volume factor on Exhibit No. 10,

reserve estimates?
A. Correct.
Q. Is that a measured number, or is that an estimate?
A. That is an estimate.
Q. And then what's the average injection rate per day per well?
A. Under the 40-acre five-spot or the 80-acre?
Q. The 80 or 40, either one. What does a well take out there?
A. Well, they all vary. An average well we're trying to keep between 200, 250 barrels of water per day. Some wells will take more than that, others will take less, but we're trying to balance injection.
Q. Is there a limit on wellhead pressure out there?
A. Yes, there is.
Q. What is that limit?
A. It varies from well to well, based on step-rate tests.
Q. What is the maximum that you're permitted?
A. I would have to go back and look. I

don't know, off the top of my head. I believe it's 1,500 or 1,600 pounds, but I would have to look.

Q. That's fine. That estimate, 1,500 pounds will probably catch it. That's about right, huh?

A. Uh-huh.

COMMISSIONER WEISS: No more questions. Thank you.

CHAIRMAN LEMAY: I have one or two here.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. You mentioned the reservoir pressure is pretty well depleted. Do you know what it was when those five wells were drilled in 88?

A. No, we don't. We weren't the operator at that point in time, so--

Q. How about when you took over the operation in 1993?

A. We didn't actually measure the bottomhole pressure, but we feel like that it was very minimal; basically, the fact that they're not putting any water in the ground except for in one well.

Q. The fact that they drilled the five wells and the sands were discontinuous, would not one expect some sands that might be encountered on a 40-acre five-spot, where you had some oil that was just left there under primary means, or are all these sands somehow, at least, in pressure communication, so that even those new sands that were penetrated were drained by primary or by the previous waterflood?

A. Based on the five wells that were drilled and then the subsequent five wells that we have drilled now, we're finding some of the sands totally pinchout on porosity and permeability. So it is highly likely that some of those sands was all primary production that had not been contacted by any waterflood at all.

Q. How were they drained under primary, if they weren't contacted under-- You said they were drained in primary. As part of the sweep, you mean, or just not in communication at all with the operation?

A. Well, the wells that were drilled primary, produced the oil from the sands that were penetrated. And these wells, then, were converted to injection, every other well. And the water that was injected in the sands that were continuous, between an injection well and a producer, probably, were swept fairly well.

The wells that had this porosity or permeability pinchout, there probably was no pressure communication in between the wells and, therefore, you saw no secondary response in that particular sand, because there was no way of communicating.

Q. Were there any sands you encountered that weren't drained in the primary? Sands that were just isolated in there that you penetrated that maybe had some virgin pressure close to it?

A. That's possible, but there's no way of isolating those sands individually. There's very little pay, or nonpay in between the two, that you could actually isolate those sands and test each individual sand. So there was no way of telling, you know, what kind of pressure or what sand was producing what oil, because you couldn't isolate them.

Q. I'm trying to visualize the discontinuous sands. Would a 20-acre spot, in other words, possibly get you more oil because it would communicate with sands there again that wouldn't be covered under the 40-acre five-spot?

A. I would say yes, but the economics, you've got to look at that end of it, too. And, based on our sweep efficiency factors, based on reservoir engineering principles, basically would say the amount of oil you would recover, from a 40 down to a 20, would be such that the economics of drilling the additional wells and associated facilities would not allow you, probably, to economically recover those reserves.

Q. You didn't have a reservoir pressure for me did you, early on, once you took it over? Any feel from that? Have you got some fill-up, in other words, that you're going to have to go through, before you get a response?

A. That is correct.

Q. About how long do you expect to be filling up before you reach a significant response?

A. We're looking at nine months to a year, to see initial response.

Q. Initial response. And, you say 20,000 barrels of oil per well was a estimate of primarily recovery on the Queen-Penrose?

A. Based on this decline curve analysis, which is Exhibit No. 5, total reserves at the bottom was estimated at 99,000 barrels for the five infill wells, of which 56,800 was produced prior to today.

Q. So you're talking about those five infill wells, nothing on a cumulative basis per well initially for primary? This is just the five infills at 20,000 a well?

A. Yeah, on an average.

Q. You didn't give a figure on what the average well made primary, did you?

A. Average primary well, based on our study, averaged 27-, 28,000 barrels.

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

COMMISSIONER WEISS: I have one more.

CHAIRMAN LEMAY: Okay. Commissioner Weiss?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. On this business about bottom hole pressure, on the new wells you drilled, did any of them flow?

A. No.

Q. Did wells flow in 1933?

A. Yes.

Q. I would say the pressure is less than it was virgin, then.

COMMISSIONER WEISS: Okay. No further questions.

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: Okay, I'll try.

FURTHER EXAMINATION

BY COMMISSIONER CARLSON:

Q. On your Exhibit No. 10, where you show an estimated project recovery of 971,000 barrels, what would be your initial production rate, would you estimate?

A. Our initial production rate, as far as right after we drilled, or after.

Q. After you get the response.

A. We anticipated peak production around 200 to 250 barrels a day from the 10 wells.

Q. And how long do you estimate these wells will produce to get to their economic limit, or until they produce their 971,000 barrels?

A. We're looking at, probably, 15 years.

Q. The money on Exhibit 11 is already spent, is that right, the 2.7 million?

A. That's correct.
Q. You spent that after you got the Examiner's Order?
A. That is correct.
Q. You spent another two million, before that period, on the unit after you acquired it?
A. Right. We spent approximately two million between February 1 and the hearing date, just on getting the unit back into shape to where you could operate on an efficient basis.
Q. You don't have a response yet to the new injection?
A. We started injection on all the wells on the 15th of December of 1993.
Q. When do you anticipate your first production response?
A. We're looking at somewhere between October and December of 94, seeing the first response.
Q. Getting to the economics for a minute, if we estimate this is going to produce an additional million barrels of oil, and that's over 15 years, and if we assume a $15 barrel price, we're talking about an additional $15 million worth of oil, is that correct, over 15

years?

A. That's before royalty and expenses.

Q. Right. And, If this tax break saves your company, I think it's 1-7/8 percent, is that correct?

A. I believe that's correct.

Q. So you're looking at a savings of approximately $300,000 over 15 years? If I use two percent times 15 million, that's $300,000.

A. Okay.

Q. You say that's enough to influence your company to decide whether to enter a project like this?

A. I'm not saying whether or not it influences whether or not we enter into this project, I'm talking about, we have more projects than we have capital. And the priority of the projects is effected by the slight change.

We rank our projects by rate of return on our capital. Some projects are going to have to be cut and, by the tax rate incentive that is included in this, it would allow us to rank this project higher than what it would normally be, and allow us to not only continue with this phase of the project but, if it's successful, continue with other phases.

Q. What is your expected rate of return on this project?

A. Approximately 30 percent. That was based on the original economics done with the higher oil price. I have not rerun the economics with the new price.

Q. Did you work your rate of return what it would be without the tax credit?

A. No, I did not.

Q. It probably wouldn't change it a lot, would it?

A. I'm not sure. I can't say.

Q. Well, if we're talking about $300,000 over 15 years, I would guess that it would very marginally change your rate of return. Do you agree with that?

A. If you're looking at undiscounted dollars. But, if you look at discounted dollars, the bulk of that production is early in the life of the project, so it would have a significant change on the economics. The farther out you receive this money on a discounted basis, your dollar has less effect.

COMMISSIONER CARLSON: That's all the

questions I have.

CHAIRMAN LEMAY: Commissioner Weiss.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. I'm mixed up now on recoveries. Now I hear 100,000 barrels per well. Is what you expect?

A. Well, I was at 99,000 ultimate barrels for the five wells that were drilled in 1988.

Q. This million barrels on reserve estimates on Exhibit 10, where is that going to come from?

A. That's going to come from the injection of the water on the 40-acre five-spot recovered in the 10 wells.

Q. 10 into that is about a hundred thousand a well, isn't it?

A. Correct.

Q. What was the average waterflood recovery on 80-acres per well?

A. Approximately--can you restate your question?

Q. You said primary is about 27,000 barrels per well. I thought secondary would be about the same on 80 acres, which is another

27,000 barrels per well?

A. On the average across the entire unit. We're talking about, in this project area, the best part of the unit and the best reservoir, and, when you take an average over the entire unit, you're averaging not only the best part but the areas that aren't as good.

Q. So, the secondary recovery and primary recovery from the wells, was also about a hundred thousand, is that correct?

A. Correct.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. Let's talk about the million barrels. You divide it by the 10 producing wells you've got a hundred thousand; but if you include the injectors in what's included on a 40-acre basis, you end up with 50,000, isn't that correct, for 40 acres, roughly? I just roughly counted 19 40-acre tracts in there.

A. Yeah, approximately.

Q. And does waterflood economics normally include injectors, as far as recovery goes? Let me state it a different way. If you're stating the average recovery is like one-to-one, the average Queen well makes 50,000 barrels, you would anticipate another 50,000 barrels.

But, when you're working your economics, you're not figuring an additional 50,000 barrels only on your producing wells? Aren't you also figuring your injection wells in there, so your total recovery, as you estimate, like a one-to-one, would be on each 40 acres in the flood?

A. Let me backtrack for a minute. The old adage of one-to-one was on the 80-acre five-spot. Based on the work that Mr. Hickman did in his study, and his subsequent work in his SPE paper, he determined, by going to a 40-acre five-spot, that upwards of two to three more of secondary oil from both the 80 and the 40, to primary, would be anticipated from a 40-acre flood.

So, we're dealing with a little bit different numbers. When you say one-to-one, that's on an 80-acre five-spot, and he's looking at two- to three-to-one if you go down to 40-acre spacing.

Q. To clarify the terminology, even on an 80-acre flood, are you including injections on a one-to-one, or are you only calculating your producing wells?

A. You calculate all your primary production from both current injectors and producers for your primary production. Of course, on secondary production, all you have is from producers.

Q. Well, without the injectors you wouldn't get it, so if you're going--

A. Exactly.

Q. --if you're looking at the flood proper--

A. No. What I'm saying is, on one-to-one, in that terminology, you add up all your production from every well in the unit, under primary, and extrapolate that out to an ultimate primary number. And then you take your producers under the 80-acre five-spot, estimate the ultimate recovery secondary from those, and that's where you come up with one-to-one.

So, just because a primary well made 28,000 barrels, doesn't mean that you expect 28,000 barrels from that well, also. You're also taking primary reserves from the injection well.

CHAIRMAN LEMAY: That was my point, I

guess. Thank you. I was trying to clarify that for the record.

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

Mr. Kellahin, you may call your next witness.

MR. KELLAHIN: Mr. Chairman, at this time, I would call Mr. Rick Foppiano.

RICK FOPPIANO

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

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Rick Foppiano. That's spelled F-O-P-P-I-A-N-O, and my occupation is a regulatory adviser for Oxy's operations that are handled out of our Midland office.

Q. On prior occasions, Mr. Foppiano, have you testified before this Division not only as a petroleum engineer but as an engineer involved with the conservation rules and regulations of the Oil Conservation Division of New Mexico?

A. Yes, I have.

Q. Pursuant to your employment, have you been the regulatory coordinator for this particular waterflood project?

A. Yes, I have.

Q. Were you present and did you attend the Examiner hearing of this case?

A. Yes, I did.

Q. In addition, have you undertaken examination of all of the Division-approved EOR projects, to identify those projects which the Division has approved that have similarities to your project?

A. Yes, sir, I have.

Q. Based upon that entire study, do you now have certain conclusions and opinions with regards to this order?

A. I do.

MR. KELLAHIN: We tender as an expert engineer, with special expertise in conservation rules and regulations.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. Before we look at your spreadsheet summarizing your work, let me have you, sir, restate your concerns, on behalf of your company, with the particular limitations that the Division has placed in its approval of your project insofar as it covers the enhanced oil recovery portion.

A. My concerns stem from the Examiner's focus on previously drilled wells in our project. It seems to me that, in reading the rules, that the rules focus on a displacement process, and that exclusion of those previously drilled wells, because it doesn't materially impact the displacement process of a 40-acre waterflood, five-spot pattern, they should not have been excluded.

So, my concerns there are, one, this is a marginal project, it needs all the help it can get, particularly with the oil prices as they are today. And, so, we are here today trying to establish a precedent, if you will, or at least some policy, as opposed to these previously drilled wells in a project where an operator comes in and asks for a certification when they're going to change their patterns in a project.

Q. In examining the Division's handling of other EOR projects, can you separate out their processing of new waterflood projects from how they have handled existing projects?

A. I'm not sure I understand the question, Tom.

Q. There's a whole list of EOR projects that have been processed by the Division?

A. Yes.

Q. Some of those apply to new waterfloods?

A. Yes.

Q. And others apply to what we would characterize as expansions of old projects?

A. Yes.

Q. All right. To understand the definition, what is your understanding of how the Division has defined new waterflood projects? What does that mean?

A. Primarily on the basis of injection. If there was not injection in the project before, on the particular reservoir that was going to be flooded, then I think that's pretty much a new project and fairly easy to handle.

Where there has been prior injection, like on one pattern, and there's going to be a change of a pattern, or if there has been prior injection in one zone and the operator wants to start in a new zone or they want to expand aerially into a different part of the unit that hadn't seen waterflood injection before, then I think those are pretty much handled as expansions of existing waterflood projects.

Q. When we look at those categories of applications that deal with new waterflood projects, are there any limitations placed upon those operators to disqualify, from the EOR credit, existing producing wells that are within those new waterflood projects?

A. None that I'm aware of.

Q. All right. When we look at the expansions of old projects, describe for us what we're talking about as the kinds of ways you can expand an existing project.

A. As I mentioned previously, a project, for severance tax purposes--and this is based on my interpretation of the rules, and my experience--a project could be expanded by including a new portion of the reservoir that had not previously seen waterflood, or it could be expanded geographically, into another horizon. It's within the same defined interval as, say, a

Queen or another type pool.

There might be another zone that's continuous and has not seen any water injection, and the operator wants to expand his waterflood into that new zone, or, as in our case, he wants to change his pattern and contact new areas of the reservoir with water injection as a result of that change in pattern.

Q. Are you familiar with the Commission-issued Order R-9708, that establishes the definition of terms, the procedure, and the rules for qualifying a project for the EOR tax reduction?

A. Yes, I am.

Q. When we look at the definition of expansion or expanded use, meaning a significant change or modification in process or technology, has the Division, in other cases, approved an 80-acre waterflood reduction to 40, as a significant change in process or technology, that allowed other operators to have a project area qualify for the tax reduction?

A. Yes, they have.

Q. Did those other approved project areas already contain producing oil wells?

A. Yes, they did.

Q. Did the only change in process that occurred was for that operator to take those existing wellbores, reconfigure them for injection purposes, and thereby reduce the pattern to 40 acres?

A. He reconfigured some wells in the project area for injection and, on the basis of testimony and evidence that existing, producing wells should see a response from this change, they were made a part of the application and were approved as producing wells eligible for the credit.

Q. Do you see any requirement or basis, either in the regulations of the Division or in the EOR Act, to put this type of limitation on qualifying a project area, by excluding those oil wells that are already producing?

A. No, I do not.

Q. Let's turn to your spread sheet, Mr. Foppiano, if you'll look at what is marked Exhibit No. 12. Before we discuss it, describe what you searched for.

A. What I did is look at the cases that were very similar to ours; in other words, change of injection patterns, where the operators had come in and told the Commission, "I'm going to change the injection pattern in my waterflood, and I wish to qualify this process under the severance tax incentive rule."

And this exhibit, more or less, summarizes some pertinent aspects from each of those applications, and it also puts ours on there for comparison.

Q. Let's turn to the first one on your spread sheet, which is the Texaco case. It's Case No. 10798, heard by the Examiner on August 12th of 93. It was heard approximately, I believe, a month after your case was heard. Yours was heard in July of 93, and Texaco's was heard in August of 93.

What did you find when you examined the definition of the project area?

A. Well, they were applying to have, just exactly like us, to change their pattern from 80-acre five-spots to 40-acre five-spots, exactly what you see here, which was the subject of our application.

In the project area that they described, and which was approved, they had 33 wells that were already producing. And the testimony was that those 33 wells should see an increase in production, like our five wells that were excluded should see an increase in production, and then they were also going to add 18 new wells, either conversions of injection wells to producers, or drill new wells. So, they were going to add 18 producing wells.

So, as a percent of the total number of producing wells that were approved in their order, 65 percent of them were already producing at the time the application was made.

Q. If you'll keep handy Exhibit 12, but turn to Exhibit 13, what does Exhibit 13 show?

A. Exhibit 13 is a reproduction of the exhibit that was used in the Texaco hearing. As I mentioned before, their application was on the basis of changing patterns from 80-acre five-spot to 40-acre five-spot. They had two pools, actually, the Jalmat and the Langlie-Mattix, so it's hard to see the patterns in this picture here because they're offsetting patterns, different for each pool.

The testimony in the record was that they were 80-acre five-spots and they were redeveloping on 40-acre five spots. Their testimony also was that it should improve the production on 33 existing producing wells within this gray-shaded area that you see on this exhibit.

Q. In the Texaco case, did it matter how much money Texaco was spending?

A. I didn't see that it mattered, no.

Q. Did it matter how much secondary oil they were going to recover?

A. I did not see that it mattered.

Q. Did it matter if they had drilled their injection wells and/or their producing wells prior to the hearing?

A. It didn't appear to matter, no.

Q. Did it matter as to how much an economic incentive it was to have the project approved for EOR purposes?

A. I believe there were some questions by the Examiner to that effect, which were addressed very similar to the way our witness addressed them.

Q. The element of enhancement or incentive is not an issue in either order, is it?

A. No, it is not.

Q. Is it a test, for the Texaco project, that producing wells had already been drilled?

A. Apparently not. It was approved

Q. Let's turn now to the Phillips case. The Phillips case deals with, the East Vacuum Grayburg/San Andres Unit, which is a pressure maintenance project, right?

A. Yes.

Q. This pressure maintenance project qualified for the EOR credit?

A. Yes. This change of pattern in these project areas did qualify.

MR. KELLAHIN: The hearing in this case, Mr. Chairman, was in Case 10779. It was heard on July 29, 1993. It was the hearing after the Oxy hearing was presented to the Division.

Q. Now, Phillips had a rather complicated process, did it not? They had five areas within the unit?

A. Yes. This was a CO-2 water injection-type project, a tertiary-type project. What the next four exhibits show, are reproductions of the various project areas that they applied for in that one application. They called them Area 2, Area 3, Area 4 and Area 5.

And Area 1 is not included because there had not been any prior injection in Area 1, so it was handled, more or less, as a new type project. And Areas 2 through 5, there had been injection going on prior, and there was a change of pattern, and that is what they were asking for the Examiner to qualify as a significant change or modification in the displacement.

Q. Let's take Area 2 and look at the map for a minute.

A. Okay.

Q. The area approved, is that area described by the blue line?

A. Yes.

Q. Within that area, what was Phillips proposing to do?

A. What Phillips was proposing to do was to add three new infill producers. There was already one injection well being used, Well #8 there. It's rather difficult to see, but it's the black circle with the black triangle around it, kind of in the center of Area 2. That was being utilized as a CO-2 water injection well.

They were going to add three new infill producing wells, #20, #13 and #21, and add another injection well, which was Well #1 there. And, pretty much what they were describing this change was, was to go from just a change in pattern. It was kind of an irregular pattern, but it was to improve the sweep efficiency inside this little project area, just like an 80-acre to a 40-acre would do.

Q. They're going to have a total of 10 producing wells within the approved project area?

A. That is correct, and seven of them were already producing at the time the application was made.

Q. Did the Examiner exclude those seven producing wells?

A. No, they were approved in the order.

Q. All right. Let's turn to Area 3. That's Exhibit No. 15. Describe what the plan was here.

A. In Area 3, the Applicant testified that they were going to change the pattern from two 80-acre nine-spots in this blue outline area, to a 160-acre line drive-type pattern. There again, another change of pattern, change of displacement type of application.

And their activity that they said they

were going to undertake was, they were going to add another injection well and three new producers in this project area. There were currently two active CO-2 water injectors, Wells #5 and #2. As you can see, Well #002 is the new injector that they're going to add there.

So they were going to have three new injection wells there, and three new producers, for a total of--they had nine existing producing wells when they filed the application, and they're going to add three, so they had a total of 12 producing wells described and approved in this project area.

Q. As the project was approved, there were five wells producing or will be producing within the approved project area?

A. Seven.

Q. Area 3?

A. Area 3.

Q. We've got--

A. There's a total of 12 producing wells, seven of which were already there when the application was filed.

Q. I'm reading on your spread sheet, the next line down. It says nine.

A. Nine, that's correct.

Q. Nine. Three new, total of 12. All 12 get approved?

A. That's correct.

Q. Let's go to Area 4. Again, what's the plan?

A. The plan at that point was basically to change the pattern from one 80-acre nine-spot, to one 70-acre nine-spot in a 150-acre line drive. And, in the process of doing that, they were going to utilize two existing CO-2 and water injection wells, Wells #6 and #8, and they were going to add one new injection well, Well #1 there, and one new producer.

In that area, nine wells were already producing and approved as part of the order, and they were going to add one producing well, so they had a total of 10 producing wells that were approved in the project area.

Q. Is the Phillips order that approved Area 4, limited only to the one new producing oil well within the project area?

A. No, it's not.

Q. It approves all 10 wells that will produce oil in the project area?

A. And the basis of that was that those wells would see increased production, they would see response from this proposed change, just like our five wells that had already been drilled would see some response from the 40-acre redevelopment that we were proposing.

Q. Isn't that the plan of the Act and of the order?

A. That's my interpretation, yes.

Q. To approve a project area?

A. Yes.

Q. And to get the reservoir engineers to look at that area, and to see if there's going to be some response? And it's not measured by individual wells, is it?

A. No. It appears the Act and the rule both describe the project in terms of area, such like we have. Once you define this is what you're going to do, and it's approved, it would seem that that's the best way to describe it aerially, as opposed to well by well.

Q. There's nothing wrong with any of these Phillips areas, is there? If that is the area that's effected, that the engineers can determine is going to be impacted by the flood, then that's what the project area ought to be, right?

A. If those wells are truly going to see an increase in their production, which should result from a change in displacement that's going on down in the reservoir, then, yes, I think they should be qualified under the rule.

Q. Let's look at the last area, Area 5, in the Phillips order. What was the plan?

A. Pretty much the same as the previous ones. Their plan here was to change the pattern from an 80-acre inverted nine-spot, to an 80-acre line drive, and in order to do that, they were going to add one injection well to the existing injection well they already had out there, and drill no new producers; just utilize the seven existing producing wells that were already there when the application was filed.

Q. Again, the same type of thing that the others had?

A. Same type of thing.

Q. All right.

MR. KELLAHIN: Mr. Chairman, Exhibits 18 and 19, Exhibit 18 is the actual Texaco order, if you want to look at the exact language. The Phillips order is Exhibit 19, and again, it has the specific details of that order.

Q. In conclusion, Mr. Foppiano, summarize for us what it is that you're asking the Commission to do.

A. We're asking the Commission to amend the Examiner's Order so it applies to the five previously-drilled wells that were in existence at the time we filed our application, which is in line with what is apparently existing policy now, as evidenced by the Texaco and Phillips cases that were approved subsequent to ours.

MR. KELLAHIN: That concludes my examination of Mr. Foppiano. We move the admission of his Exhibits 12 through 19.

CHAIRMAN LEMAY: Without objection, Exhibits 12 through 19 will be admitted into the record.

CHAIRMAN LEMAY: Commissioner Carlson.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. Were there any cases, prior to your case, before a Hearing Examiner? The Texaco and Phillips case were subsequent to your hearing?

A. That's correct. Commissioner Carlson, there was a prior case. We call it the Marathon case. It was pretty much the first one out of the box for expansions.

In that case, and I suspect it was the source of the Examiner's reluctance in granting us everything we asked for, but, in that case, what distinguishes us from that one is that the operator, when they came in and filed for that, they had done all the work, they had converted all the injection wells, and they were sitting there, waiting, when they filed the application.

So, all the work had already been done, as opposed to our case, which is, we came in and we said, "We've got a project. It requires the conversion of existing producers to injection service, drilling of new wells," and we had not spent that money when we filed the application. It was a project that was down the road.

Whereas in Marathon's case, I can understand the Examiner's reluctance. They were worried, Was this truly an incentive? So I think, through an exercise of caution, Marathon was denied.

Q. In your examination of the files in these cases, you mentioned there wasn't much discussion of the economics?

A. There was in the Texaco case. As I recall from the transcript, there was some decision on the economics. There was some question, in fact if I recall correctly, about the effect of the tax incentive. You know, was it truly an incentive, this kind of thing. Similar to the same questions you were asking of our witness.

Q. Is it your opinion that economic considerations are pertinent, when considering whether a major expansion is going to occur?

A. I don't think it should be a test for the Applicant, that the incentive makes or breaks a project, because in truth, Commissioner, I don't think any of us would be before you if that was the test. It is an incentive.

I think certainly it's appropriate to ask questions and elicit testimony about how much of an incentive it is, but to deny a project on the basis of the fact that it may not be much of an incentive, causes me, at least, some problems because--it's kind of like, we look at these incentives in total.

New Mexico has an incentive, the feds have an incentive, with the FIT tax credit and the royalty reductions, and we try and take advantage of every single one we can to improve the economics of our project. That's the approach we take.

I think it's fair to ask what kind of an incentive it is, but I would hate to see the Commission deny any applications on the basis of how much of an incentive it may be for an operator.

Q. But costs and economics should be indicative if it is, in fact, a major expansion, versus just something in the normal course of business of operating a unit, isn't that correct?

A. Sure. I think there's potential for abuse. There's potential for operators to do a very, very insignificant change. Add a little bug to the water, or something like that, that costs 2,000 bucks a month, and come in and ask for a severance tax incentive and get a huge windfall over something that doesn't really mean much and is really, obviously, trying to get something for nothing.

So, because of that potential for abuse, I think it's very proper to examine, what are you spending? What kind of activity is this going to be, in terms of drilling new wells? and that kind of thing. I fully agree with that.

COMMISSIONER CARLSON: That's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: Yes.

EXAMINATION

BY COMMISSIONER WEISS:

Q. I have a question concerning your interpretation of the rule. On page 5 of Exhibit 2, specifically 2(A)(3), what's a "positive production response," and how did you go about that part of it? and how did these other people do that? I think you have to do something about that before you get tax relief.

A. Yes. That's my understanding, also, is that this is just a, more or less, three-phase process; Phase I being to certify the project area, Phase II, after you've commenced injection, you come in and show that you've received some response from this project, and then Phase III you go to the Revenue & Taxation Department and get your credit.

Your question is, if I interpret it correctly, how would we show our response?

Q. Not only that, but how have these other people, Texaco and Phillips specifically, done that?

A. To my knowledge, no one has come in yet with a response.

Q. How do you plan to do it?

A. Based on my experience, and this is a very similar law to Texas, and I have filed all over for my company in Texas, I've done some of the response certifications, I would propose that because Phase I of this process is a technical review of the project and what wells and area would be affected by the Applicant's proposed project, that the second phase should be a very--just a very factual review of looking at the production, the injection, and those things from the project, and in total.

In other words, like if you were talking to Oxy, "You said you were going to convert these wells, drill new producers," so forth and so on. You come in for response certification, "Did you do what you said you were going to do? If you did, show me what response you got from it. Show me your production graph on the project area, all the producing wells in the project area. Do I see injection on there? Do I see a response to that injection?"

Then, if so, I think the response should be certified and backdated to the date the response was first observed. I think it's pretty much looking at the production and injection, and evaluating the operator's plans; what he did, compared to what he said he was going to do.

Q. Now, this is hypothetical. Let's say, in your case, your field people perforated the Seven Rivers by mistake, put the water in there and didn't get it in the Queen, so you wouldn't have any production response. Then you're not entitled to any tax relief, is that correct?

A. And there may be one particular problem on a well-by-well basis in this project area that, for some reason, has not seen a response. In my mind, asking the Applicant to wait until he's got a response, on a well-by-well basis for his project area, is going to present a tremendous burden on the Commission, and is going to present a tremendous burden on the operator.

There's a lot of things that can change or effect the production, when you look at it on a well-by-well basis; changing out a pump, stimulating the well, these kinds of things. Plus, they all will not see a response at the same time.

Particularly in Texaco's case, the wells closest to the injection wells are going to see a response before the wells farther away do. And should an operator have to wait until every well sees a response? In my mind, I don't think so.

I think if the project area sees a response, if the operator did what he said he was going to do, and the project area production increases as a result, then that response should be certified.

COMMISSIONER WEISS: Thank you. I have no more questions.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. I would like to explore this, how to qualify an area, because it tends to affect the overall response. Agreed, we haven't seen a positive production response. But let's play some hypothetical games again.

A. Okay.

Q. Oxy wants this yellow area--and I'm

back on Exhibit No. 10, the one that's on the board up there.

A. Okay.

Q. You are looking for a positive production response in the area that's yellow. Would it be your interpretation if that well, say, for example, Well #20, that's not in the yellow area, would receive a positive production response, that would be the one in the northeast quarter of the northwest quarter of Section 5--

A. Yes, sir, I see it.

Q. --would you expect to retroactively get that well qualified as a tax credit well, because it's outside the area but would receive a response?

A. My intention was, and I'm the one that told our guys how to draw the project area, was to take a very conservative approach on an area that would be affected by the 40-acre development pattern. I believe there's potential for Well #20, and other wells that are surrounding the proposed new injection wells, to see a response, but they also will see some influence from some other wells that are already on injection or have been injected into before.

So, my intent with the yellow area was to be very conservative and just confine it to the 40-acre patterns that we were proposing. But, I think the case could be made to add more wells on the outside, apparently, as some of the other operators have done in subsequent applications.

Q. Do you see the problem, the dilemma we're facing here? You're coming to the Commission, and before you inject water you're saying, We're going to spend this amount of money. This is the area we think will be affected by our investment. And then, after the fact, you'll make the investment, you'll come back, and you may or may not receive responses within that yellow area, you may receive responses outside the yellow area, you, in essence, redraw the yellow area to conform to where you receive the positive production response.

But the way I see the rules and regulations in the bill, we would only certify, within that yellow area, a positive production response. That may take some fixing. We're concentrating on the qualifying area now, and that's why I raised that point.

Specifically to your project, let me play one more scenario with you, and I want you to think closely about the answer to this. Let's assume those five wells that were drilled in 1988 were drilled in 1973, and let's assume that those wells had received some kind of a benefit by the response of the flood back then. Would you be here today, trying to qualify those wells as being part of the yellow area for the positive production response?

A. Most definitely.

Q. Why?

A. Because the displacement process is significantly changed by reducing the pattern from 80-acre to 40-acre. You're contacting new areas of the reservoir you haven't contacted before, because of the discontinuity of the reservoir, as testified to before, the infill drilling improves the sweep efficiency. All these things are happening to increase the recovery of oil in these patterns.

Q. I asked you to think about that question. Had those wells been drilled back in 1973, would not that particular part of the flood be a five-spot flood, and would not that have benefited, then, by what amounted to maybe a five-foot 40-acre flood within an 80-acre area?

A. You don't have a five-spot 40-acre flood until you have injection in the four wells surrounding the center producing well, and that's what changes the displacement process, in my opinion. You have to put water in those four offset wells in order to have the change in displacement.

Just the fact that you had them there and they were producing--in fact, I could make an argument that it's more beneficial, because you're recovering the primary portion of the reserves in that area, and all you have left is the secondary associated with the 40-acre redevelopment.

Whereas on these new drills, there's some flush production there, and there's a potential for a little more oil to get qualified with those new wells than would have gotten qualified with the old ones, because you've depleted the area more with the old wells.

Q. Well, the next witness may get into the legislative intent, but my question was because my interpretation of the legislative intent would be, if capital investment was being made, and "significant" is probably a pretty good word there, then the operator would be entitled to the benefits of tax relief.

If the wells were already there, and what you're doing is, agreed, going from an 80-acre to a 40-acre five-spot, but, in essence, only injecting water, reversing the pattern with wells that are already there, isn't there some question in your mind whether that should qualify?

A. Well, here again, no, there isn't, because it takes significant investment to commence the 40-acre injection, even when you have those wells already drilled there. I think one of the prior exhibits illustrates that the five wells that we propose to drill, represent about a million dollars of that 2.7 million dollars we were going to spend.

So there's 1.7 million dollars additional capital we're going to spend, which I think is significant capital we're going to spend, which I think is significant, just to convert the injection wells, even if all 10 of those wells had already been drilled.

I think that's a significant investment in conversions and waterflood facilities that is necessary to get the 40-acre displacement pattern, which is really the thing that results in the increased production of oil, and I think was contemplated under the Act, when the Act refers to a significant change or modification in the displacement of oil. That's why I keep keying off of--injection, really, is what is changing.

Q. You understand our problem. What we're trying to do is get away from adding a few bugs, and giving the credit to a significant investment that would truly recover more oil when getting the credit, and we're trying to draw that line. That's why all these questions, I think, are significant in trying to boil down, what should qualify as a qualifying area? How do you qualify an area?

A. And I think the Commission's approach in scrutinizing these closely, on the first pass, is valid. I think the Commission should look very closely, and force operators to be conservative on their project areas that they draw, and make them go through the hoops on that first pass.

But then, at least in my view, when an operator has done what he says he's going to do and comes back to the Commission for response certification, that really should be looked at on a project area basis. What is the production from that approved project area?

Because you've already jumped through the hoops about, what are you going to do and what should be affected as a result of what you planned to do. You really shouldn't have to go through the hoops again, unless you significantly changed, you only did half of what you proposed you were going to do. That's a legitimate reason for cutting down the project area, I think.

In our mind, if we did everything we proposed to do, we had one or two wells there that had not yet seen response, should we be forced to wait until every well has seen a response, or should those wells be thrown out because they had just not yet seen a response when we come in for the application?

And I understand it's backdated, but we're trying to get the incentive today, to affect our economics, our operating costs, so that we can be here three years from now to continue to produce.

Q. But you did testify as to that area initially should be a conservatively drawn area, both by the operator and by the approval of the Division or the Commission?

A. In my opinion, yes.

CHAIRMAN LEMAY: Are there additional questions of the witness?

MR. STOVALL: Mr. Chairman, I would like to ask one, actually, regarding that same question.

EXAMINATION

BY MR. STOVALL:

Q. You talked a little bit about the question of, what if you see a response in a well outside the area, and you've also stated that if a single well in the area doesn't show a response, that shouldn't necessarily disqualify the receipt of the credit.

What if, let's say in this situation, that northeast corner, you get a positive production response overall, but it appears from the data that one or two production wells in that northeast corner of the project area are not responding, I believe it's been the Division's thinking that, in that case, the project area might be reduced, rather than an isolated well in the middle, for an area of the project area which did not respond to the efforts.

A. Are you going to penalize us for having a more marginal waterflood?

Q. No, I'm not saying penalize you, but I'm saying when the point comes that you get a positive production response, the whole project area might not qualify. We might find a portion of the project area which did not qualify because that portion, looking at the whole portion, did not respond at all to the flood.

A. My concern would be that because of the reservoir quality throughout the project area, you're going to have some wells that will see immediate response, and you're going to have some wells whose response is delayed. They will not respond all at the same time.

In our case, admittedly, I think the response will occur probably within a 12-month period of time, on all wells. But, in other cases where we've seen, and in cases we have that we're looking at right now, you're going to have wells that do see a response much later than they do today because of their proximity to the injection wells and because of the reservoir quality, these things.

And to exclude those wells just because they haven't seen the response at that time, I don't think was the intent of the Act. I think it was the intent of the Act to give it wherever you might see a result in the project that you're instituting. That's where the engineering review comes in, in the first process. What does it look like, from a technical and engineering standpoint, should be affected by what you're proposing to do.

Q. In other words, what you're suggesting is that, the way the rules are, once the project area is qualified, that fixes the area regardless of what happens in terms of response?

A. In terms of response, yes. In terms of the operator's plans, if he doesn't do everything that he said he was going to do, then I think that's certainly a legitimate reason for cutting down the project area.

But, in our case, we've converted all

the wells, we've got injection going into all those 40-acre five-spots, but we have response on nine of the 10 wells. I do not believe it's fair to force us to exclude that one well we haven't seen a response on yet, because we should see a response.

In fact, if we haven't seen a response, there's not much oil there that's associated with the credit, anyway.

CHAIRMAN LEMAY: Rick, I've got to jump on that one for a minute.

THE WITNESS: Okay.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. You're talking about what's fair. Is it fair to include an additional well that receives response that wasn't in the area, and not reject wells that were in the area and did not receive a response? Seems to me, if you're going to take one, you've got to take the other.

A. If I was redoing this application now, I would draw the project area bigger, to include the wells that might see any kind of response from the injection wells.

Q. From a regulatory point of view, we

have a problem, I would think, if we agree it has to be conservatively drawn, you stated that, and yet, if you're going to get the credit on the maximum amount of acreage you included in the project, it would be to your advantage not to be conservative, but very, very liberal.

A. Exactly.

Q. Because, no matter what the responses are, you're going to claim that that's the area affected; and, therefore, you ought to get it for that whole area. So then we argue, subjectively, what is conservative and what is not conservative.

You see the problem we get into with the yardsticks and the intent, and how we tend to enforce that as a regulatory agency?

A. It's tough.

Q. Also, the idea of including the well, which I thought we mentioned that might be outside the area, that received a response, gave it the tax credit, but areas like Mr. Stovall came up with, that, for some reason were tight, didn't receive a response, give that, too, because it was part of the initial project area.

A. That's a good point, and it raises a

question in my mind, if, when we come in for response certification, could we ask for wells that were not included in the original project area that we think have seen a response?

Q. I think that will get some attention, when you come in for positive production response certification.

A. It's a very difficult issue, Commissioner LeMay. It's very difficult. And I think that's why the Phase I of this process is so important, that the review of what the Applicant's proposing, and a determination be made as to what could be affected or what will be affected by what the Applicant's proposing to do.

But, once that determination is made, I do have a problem with, Well, not every well responded the way you said it was going to happen, so we're only going to give you the credit on a well-by-well basis.

What about the projects where you have hundreds of wells? Is an operator going to come in with 100 production graphs and go through, graph-by-graph, for production response? I think the intent of the legislation was to look at it on a project area basis. And, if you show a response from the project area, then you should get it certified.

Q. As a practical matter, if you have one well that didn't receive a response, it was tight and it didn't receive a response, what financial harm would you suffer from that well being excluded because it didn't make any oil anyway?

A. At the time, yeah. My point is, it may see a response later on down the road.

Q. Couldn't you come back with another production response at that time?

A. I don't know.

Q. I think we'll have some questions the first time we receive an application for positive production response.

A. We're going to let some others blaze the trail for us.

MR. STOVALL: Mr. Chairman, I would like to just state what the Division has done in these hearings and what it's stated, so that the Commission can address the issue. I think it's a real concern.

I think the Division has taken the approach and looked at these project areas as sort of a maximum area that can qualify for a response. We've stated this to Applicants when they've come in on these, that you can come in and certify your area.

And then, when you come back for the positive production response, the Division reserves the right to take another look and say, okay, a portion of the project didn't qualify. It didn't receive the response.

I think the reason that we've taken that approach is because--well, Mr. Foppiano may have been conservative in his approach, but I think some operators are going to be less conservative and seek a larger area. If we don't have the ability to look at areas, not individual wells, as we're talking about here, where you've got a tight well in an area surrounded by--but where you have an area in the project that's identified originally, that doesn't respond, then you can say, That really isn't getting the benefit of that effort.

The Division has taken the approach that we can reduce that, and I think we've also taken the approach that once the project area is certified, it's going to be difficult to expand it. You're going to have to come back in and get a recertification of the expanded area, and then show your response. And that gets tricky.

But I think, from the Division's standpoint and how the Division has approached these cases to this point, that is an issue for which the Division needs clarification on from the Commission.

Essentially, I'm disagreeing with Mr. Foppiano. In his case, if he's been conservative, he should get a response throughout the whole thing and it shouldn't be an issue. In cases where operators are not conservative and go for the maximum area, I think the Division's inclined to say, Okay, it looks like it might happen. We can certify the maximum area; but, when you get a response, we're going to look at where you really get a response.

The Division would request guidance from the Commission at this point.

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

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Mr. Foppiano, does the tax incentive apply to what portion of the oil produced from the yellow area there?

A. From my understanding, if the response was certified, the tax credit would apply to all oil produced in that area.

COMMISSIONER WEISS: Thank you.

CHAIRMAN LEMAY: Additional questions? If not, the witness--

COMMISSIONER CARLSON: I might have one.

CHAIRMAN LEMAY: Commissioner Carlson.

FURTHER EXAMINATION

BY COMMISSIONER CARLSON:

Q. In response to what you and Mr. Stovall said, is it your opinion that the Commission, upon certifying a positive production response, can actually amend the area? I'm looking at the Act and the regulation, and to me they certify "yes it has" or "no it hasn't" and they really don't go back and amend the area.

Maybe Mr. Carr can address this when he gets into the legislative intent of this, but if that's the case, I would like to hear your opinion of whether or not they could certify, maybe, X percent of the production from this area that qualifies, rather than a hundred percent, as you just said?

A. My opinion to your first point is, I think that is the issue that Mr. Stovall and I disagree on, a little bit, the extent of the Commission's review of the project area when the operator comes in and attempts to get the response certified.

I believe the Commission is certainly proper in reviewing the project area in terms of, what did the operator say they were going to do, and what did they do. If we propose to do these many patterns and we only did half, then I would not expect the Division to approve all the production from that area just because they approved that before. I think the potential for abuse there is rather obvious.

So, I think it's proper for the Commission to review the project area, but I do have concerns with the Commission looking at it on a well-by-well basis, and throwing out the ones that haven't seen a response, or it's not clear that they've seen a response, and keep the ones that have seen a response.

I would be in favor of, and it may be that the Act or the rule doesn't allow for it, but I would be in favor of these particular situations being dealt with with a baseline curve, such that an operator establishes that they have some baseline production that would have occurred had they not done anything, and that the credit apply to the incremental amount above that baseline curve.

In fact, this is how we handled this very same thing in some other jurisdictions. We establish the baseline curve, it's approved, and then once your production response is certified, the amount of credit you get is the incremental of oil above that baseline curve that was approved when the project area was certified.

CHAIRMAN LEMAY: Commissioner Carlson, I need to jump in on that one.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. I know that was considered in the law, and when it was considered, it was considered a hundred percent severance tax relief for the incremental oil, and it was felt easier to administer at 50 percent of all the oil just because of the calculations and the engineering required to identify that incremental oil.

So, in essence, your argument was taken into consideration when the Act was passed, and really incorporated in the severance tax relief that was granted.

A. And maybe that's the issue about looking at it on a well-by-well basis. Because it's only a 50-percent credit, that it may not be necessary to actually look for a response on a well-by-well basis, to determine the response area that qualifies.

MR. STOVALL: Commissioner Carlson, the question you asked is the one the Division would like the Commission to answer for us, with regard to a change in the project area after the initial certification.

THE WITNESS: And I would echo Mr. Stovall's concerns, to the extent the Commission could give us some guidance on how to do these response certifications, it would be very much appreciated.

Q. Well, our jurisdiction in this case is not so much to redraw your area, is it, as to look at those five wells which were drilled that were eliminated from consideration by the Examiner order?

A. Our order approved our project area as a list of wells. I guess as part of the relief, we would ask that our project area be designated aerially, as shown in the yellow outline there, instead of on a well-by-well basis. Hopefully that lays the groundwork, when we come in for response certification, that we look at that on an aerial basis, as opposed to a well-by-well basis.

Q. But the response certification, I take it, is that part of our duty today? I don't believe that it's part of the case today.

A. I don't think so, but it may impact that, later on down the road, the way you rule today.

CHAIRMAN LEMAY: Anything else?

MR. STOVALL: I think the answer to your question is probably in the ordering provision you're correct, do those five wells qualify for the project. I think, in the way of findings, you can give some direction as to, you know, whether it's an aerial approach or a well-by-well approach.

CHAIRMAN LEMAY: Additional questions? If not, the witness may be excused. Thank you, Mr. Foppiano.

Let's take about a 15-minute break here, and come back for legislative intent.

[A recess was taken.]

CHAIRMAN LEMAY: We shall resume. Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, thank you. At this time, I would like to call Mr. William F. Carr.

WILLIAM F. CARR, ESQ.

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

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is William F. Carr. I'm an attorney in private practice in Santa Fe, New Mexico.

Q. Mr. Carr, does a significant portion of your practice consist of presenting cases to the New Mexico Oil Conservation Division and Commission?

A. It does.

Q. Are you recognized by the New Mexico

Bar Association's Board of Legal Specialization as a specialist in the area of oil and gas law?

A. Yes, I am.

Q. Were you a registered lobbyist involved in the formulation and passage of what we've described before the Commission as the Enhanced Oil Recovery Act?

A. Yes, I was.

Q. Did you testify as an expert witness before the New Mexico Oil Conservation Commission, when it promulgated its rules and regulations on the Enhanced Oil Recovery Act, that is adopted and identified as Division Order R-9708?

A. I did.

Q. As part of your practice, do you render legal opinions concerning the Enhanced Oil Recovery Act and the Division's Order R-9708?

A. I do.

Q. As part of your practice, have you presented to the Division examiners various applications on behalf of your industry clients, to have their various projects certified and approved as enhanced oil recovery projects?

A. I have.

Q. And in 1961, were you the parliamentarian of the Santa Fe High School Gavel Society, and a member of the Santa Fe High Debate Team, making a presentation on behalf of that organization to the forensic group in Albuquerque on April 7th and 8th of 1961?

A. It was the 9th and 10th, I believe.

Q. And is this your photograph, Mr. Carr, in 1961, talking to a Mr. Byron Meyer in the old high school downtown, that's now the City Hall? Is that you, sir?

A. That is.

MR. KELLAHIN: We tender Mr. Carr as a legal expert on the Oil Recovery Act, and to ask him to render his expert opinions as an expert on that subject, concerning the legislative history and the purpose of that Act, as well as the requirements under Division Order R-9955.

CHAIRMAN LEMAY: He's qualified in that regard, and also as a high school debater.

[Discussion off the record.]

Q. (BY MR. KELLAHIN) Mr. Carr, do you have an opinion, sir, with regards to the purpose of what we've described as the Enhanced Oil Recovery Act?

A. I do.

Q. And what is that opinion, sir?

A. The Act was promulgated to encourage enhanced oil recovery projects in New Mexico by providing an incentive to operators to go out and develop these programs.

The purpose of the Act was to improve the economics so that these projects would be implemented in a timely fashion, and recovery maximized. When I say "timely fashion," the concern was that these projects be implemented as soon as possible so that other related costs, like reservoir fill-up, and use of available wellbores, those kinds of things, would not economically undercut operator efforts to implement secondary recovery projects.

Q. Did you participate, on behalf of the industry, with the actual presentations of the requests before the various legislative committees?

A. I did.

Q. Can you describe for us the objectives of that Act, as you understand them to be?

A. I think it's important to note that the New Mexico Supreme Court has said that even legislators cannot testify as to what the intent of the legislature is, so what I'm saying is basically a review of legislative history, which I believe you, as a Commission, can consider in implementing an Act in a fashion consistent with what the legislature intended. So, that really isn't just form over substance, I think there is a real difference there.

The question was, what was the intent of the Act?

Q. No, sir, to describe for us, based upon your personal involvement, what was the legislative history of this Act to obtain what purpose or what objective?

A. Legislative history involved interim hearings in 1990, legislative presentations to the legislature in 1991, and enactment of an Enhanced Oil Recovery Bill that was vetoed by Governor King.

We were modeling the Act after Texas legislation, by and large, and during that period of time in 1990, there were amendments to the Texas bill, so the bill we came back with in 1992, actually was amended in certain respects to--in response, basically, to what had occurred in Texas, and it was amended specifically to include expansions of existing enhanced oil recovery projects. That was the primary amendment.

The bill was passed again in 1992, and signed by Governor King, and became effective in mid-1992.

Q. Let's go back to the basic objective, I've handed you what we've marked as Oxy Exhibit No. 20. It's the illustration in front of you. Describe for us what was presented, in terms of the purpose of the Act, when this presentation was made to the legislature.

A. This may be the most overused exhibit since Al Greer brought the Canado Hijitos Unit, but what this basically is, this is an exhibit that was presented by Amerada Hess, to the Division, concerning their projections for the North Monument Grayburg/San Andres unit.

The area shaded in red, the spike on the right-hand side, shaded in red, shows what they were estimating to be additional recovery as a result of the waterflood project.

I think the purpose of this exhibit, and this exhibit was also involved in some interim committee hearings in 1990, was to address--it really addresses the question of the 50 percent tax credit. The light green on the right shows what was projected as remaining primary recovery, the red spike being the additional recovery as a result of the enhanced oil recovery project, and the concern was, how do we allocate production between the new production, as a result of the waterflood project, without also giving a tax credit for remaining primary.

So an arbitrary number, 50 percent, was selected, and it was a number that, I think, was generally conceded would, in most circumstances, favor the state. But the tax incentive rate is 50 percent of the severance tax. The reason is, it's to try and honor remaining primary production. That's why the 50 percent figure was adopted. It also only stays in price while the price of West Texas intermediate crude stays, on an annual basis, below $27, measured May 1 of each year.

Q. When we're talking about a project area, as we've now used the term within the rule, what was presented to the legislature as the understanding and meaning of a project area? What was that for?

A. The whole Act is based on the concept of a project area, not on individual wellbores. I think the reason for that was simply to try and honor the way secondary recovery efforts go forward. They go forward on a project basis, and not on an individual well basis. That's why the whole Act and all the regulations, really, are couched in terms of project areas.

Q. When we look at a project area, is there any rule, regulation, or any provision of the Act that requires the exclusion of existing producing wells from a project area, before that area can be certified for the tax reduction?

A. There's nothing in the Act that would exclude any area from being included within a project area because of preexisting wellbores, whether they're wells drilled two or three years ago, or 15 or 20 years ago.

The legislature determined that an incentive was appropriate, and then it's passed to the Oil Conservation Division to determine what is an appropriate project area. And the test is whether or not there's going to be displacement of oil as a result of a new enhanced oil recovery process.

So, the fact that there's an existing wellbore, recently drilled or drilled many, many years ago, doesn't, in and of itself, affect eligibility of that area for certification under the Act.

Q. Do you find any provision of the Act, or the rules that implement the Act, by which the drilling of a well, or the failure to drill a well, is a test for certification of a project area?

A. No. I'm aware of nothing in the Act, or the rules, or the testimony, when either were adopted, that would make the drilling of a well or the absence of that, a condition precedent to qualification.

Q. In terms of qualifying a project area, what significance, if any, is applied to the cost of that project?

A. The cost, as I understand--what we presented concerning the cost figures, it's exactly what Commissioner Carlson addressed in his questions of Mr. Foppiano.

The reason this whole area is entrusted

to the Oil Conservation Commission, or Division, is to assure there is no abuse. That's one factor to consider in determining whether or not you have a bona fide enhanced recovery project, and that is, there are truly costs associated with this.

It isn't a change in some insignificant factor, that you'll then come running in and say, well, this should qualify the project as a significant change in the enhanced oil recovery method employed, something like that.

Q. When we're talking about significant changes in process or technologies, or the expansion, either geographically or geologically of a waterflood, was there any specific testimony, by any of the legislators to any of the interim committees, with regards to how to handle expansions, if you will, within an existing project?

A. Don Whitaker, Representative from Hobbs, was the primary sponsor of the bill. As I indicated a few minutes ago, after the bill was vetoed, there were certain amendments proposed to the bill. These were developed, actually, in consultation with Oil Conservation Division staff.

In testifying before the House Business and Industry Committee, and I don't have the exact date but it was during the 1992 legislative session, Representative Whitaker testified as follows, and I quote:

"As I indicated earlier, the bill has been amended in certain minor ways. Language has been added at the request of the Oil Conservation Division to provide for approval of expansions of existing enhanced recovery projects. We have also deleted language which would preclude any existing unit from being approved as an enhanced oil recovery project."

That's the only testimony that I could find that addressed that, but it does indicate that the amendments were proposed to permit qualification of any existing unit, if it met the other standards announced in the Act.

Q. With regards to defining an operation, what if any significance is attached to the activity of actually injecting water into the reservoir? Does that have any significance, in terms of qualifying a project under the Act?

A. We didn't follow the same approach that was followed in Texas, where they actually defined commencement of operations as putting the fluid in the reservoir. The way the bill and the rules have been implemented here, is that a project area will be approved, but the certification of the project as a qualifying area, not that there's been a production response, but that certification is made to Taxation & Revenue after the operator advises the Division that they are about to commence injection.

So, it seems to me they're consistent, and the commencement of injection of fluids is the point in time where certification of a project area occurs.

Q. Will it disqualify a project area from being eligible for certification if activity has already taken place in the project area, whereby injection wells and/or producing wells, in fact, already exist within the project area?

A. The key thing, as I understand the Act, is injection of fluid, not the drilling of wells, not preparation of the project area prior to that actual physical commencement of operations; i.e., injection of fluid.

Q. Mr. Carr, do you have an opinion whether the limitations placed upon Oxy's project, by Order R-9955, are required either by the EOR Act or by the Division rules implementing that Act, which are set forth in Order R-9708?

A. My opinion is that there's nothing, in either the statute or the Act, that would exclude an area because there was a preexisting well, as long as there hadn't been commencement of injection. Because the test isn't the existence of wellbores, the test is whether or not there is a commencement of an activity that displaces oil in the project area.

Q. Do you have any recommendations to the Commission with regards to how they should handle that issue that's now placed before them in the Oxy order, concerning the disqualification of the five preexisting infill wells from the project area?

A. In the Texaco order, in the Phillips order, these were orders involving, in Texaco's case, waterflooding both Langlie-Mattix and Jalmat pools, where there were existing wells, and they were going to workover wells and open zones in, say, a Jalmat well in the

Langlie-Mattix or vice versa.

Nonetheless, they were working with a number of wellbores that were preexisting, and the approach taken by the Division in that case and the Phillips case was that the existence of the wellbores wasn't the test, it was whether or not you are implementing a bona fide waterflood project, and are you going to ultimately come back and show an increase in production because of the displacement of oil.

If the same standard is applied to the Oxy case, then the test isn't that wells exist, but ultimately the proposed waterflood will result in additional recovery from those particular wells. As such, to just exclude them because the wellbores are there is inconsistent with two actions taken by the Division since the Oxy order was entered.

MR. KELLAHIN: That concludes my examination of Mr. Carr. We move the introduction of Exhibit No. 20.

CHAIRMAN LEMAY: With no objection to Exhibit 20, the exhibit will be received into the record.

CHAIRMAN LEMAY: Commissioner Carlson.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. Mr. Carr, who were you lobbying on behalf of during the 1991 and 92 sessions?

A. I lobbied at that time for Atlantic/Richfield and for Amoco Production Company, and I testified as a representative of the New Mexico Oil and Gas Association.

Q. The Enhanced Oil Recovery Act was vetoed in 1991?

A. Yes, it was.

Q. Do you know the reason for that veto?

A. No, I do not.

COMMISSIONER CARLSON: I have no further questions.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: I have no questions.

CHAIRMAN LEMAY: Mr. Carr, I have one question that pertains to your exhibit, actually.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. I've looked at this exhibit I'll bet a hundred times, and always wanted to ask this question. Who took the bite out of that primary production?

A. I have no idea.

Q. Everything is smooth, and all of a sudden there's a big bite out of the primary production. The key question is, if we accept your argument, I guess, that the test is truly the injection of water and the commencement of activity, we're talking about the area affected, aren't we, by that activity?

A. That's right.

Q. Is it your testimony that that area affected should be the project area, or presumed to be affected?

A. I think that the whole thrust of the Act and the regulation focuses not well-by-well, but on project areas. I think if you address that, you have to recognize how different these projects are going to be as they come before you.

The Texaco project, Arco/South Justis, are brought to you in phases, and they're talking about certifying subparts of the unit, as they go forward with their effort. I think, in most cases, the project area is something that you will be looking at. Certainly, anything beyond the project area isn't in the game, and you don't have to deal with whether or not production from wells outside the original area see a positive production response or not. They're just simply not part of the process, as it's set up.

But, as you'll get to looking at what's in the unit, what's in the project area, and what portions of that may have seen an actual production response, I think you're going to be called upon to determine how much of the area has actually experienced the response.

I suggest that, in the huge unit, South Justis, the Texaco unit, that well-by-well reviews, as to every single wellbore, may be inappropriate. I would suggest that in a unit like this, if you're not seeing a positive production response at the time certification comes in, to disqualify it, because it isn't producing.

It's sort of a two-edged sword. Why should Oxy care? Why should the state care? The fact of the matter is, the whole project area is what, I think, you really should look at. In response to an earlier question, do you have authority to make that kind of judgment? Absolutely, you do. The Act says that the recovered oil tax rate shall apply only to crude oil produced from the area the Division certifies to be affected by the enhanced recovery project or expansion.

So, you have authority. And I think what's really going to be required and would be important in the findings that come from this case, is some guidance, so that when we come back in we don't find ourselves--and I'm not meaning anything negative by this--but in a nitpicking, nickel-and-dime approach to what is an effort and an incentive that's been authorized by the legislature but to what is an informed decision upon what general portion of this project is effectively and truly part of the waterflood, and is responding to the waterflood. That's the kind of question I think you'll be asked, and that's what I think you are being asked to do when those cases come to you.

Q. You're asking to put some findings in this so we can get some guidance as to what to expect when they do come in with their certification requests?

A. I think that would be helpful, and I think to just require throwing out a single tract because there may be some particular problem with the way the well was completed or something, goes far beyond what anybody intended. And, basically, it's a project area review.

But, certainly, if the north half of the project isn't seeing any response, then I think you're authorized by statute not to certify that portion of the project area.

MR. STOVALL: Let me get a clarification, Mr. Chairman. That was kind of what I was asking about before.

EXAMINATION

BY MR. STOVALL:

Q. There are two certifications involved, one is a certification of a project area at the time of application, and the other is certification of response?

A. Yes.

Q. Your last statement was about not certifying, say, the north part of the project. Is that the positive production response certification?

A. Yes, that's what I'm talking about

there.

Q. Is that consistent with what I had discussed with Mr. Foppiano and asked the Commission to address before? Are you supporting that statement?

A. I think I'm supporting that statement, but to support Mr. Stovall's statements always make me nervous. But, I think there's a balance that has to be struck between looking at an area and saying, yes, they're seeing a response in 90 percent of the wells out here, and it's appropriate to certify the project at this point in time. I think that's one kind of a determination.

I think what operators are afraid of is that with an 80-well project, of 12-A and of 17-C, and on and on, are going to be little windows through this, and it becomes a nightmare.

And also, the way the Act functions is that, after you see a production response, you come in and ask for certification. It doesn't mean you need to come in the first month. You may wait a year, because the tax credit will be effective back at the date you--you set a date when you see that. So, we shouldn't have to wait until we start seeing a response in the large area, until we have every well responding, to come in and ask you to make that determination. I think that's taking too hard a read on the Act, and it also, I suggest, gets beyond bringing it to the Oil Commission.

It comes to you, as the Court says, "with special expertise and confidence to deal with these questions." If it was every single well having to be evaluated, on a stand-alone basis, I suspect there could be a form devised by the Taxation & Revenue Department, where a clerk could look at a number, look at another number, yes, there was a waterflood, and certify it well-by-well.

So, I think what operators are concerned about, now that we have gotten areas approved, and one, Yates Petroleum in particular, is planning to come back and seek certification to Taxation & Revenue in the very near future. We're moving to that point, and some general guidance on how you would view this would be helpful to us in preparation for this next round of hearings.

CHAIRMAN LEMAY: Do you think, Mr. Carr, that we, as a Commission or Division, as a certifying process, could certify a portion of the area subject to additional portion of the area being certified at a later date, if and when a production response was received in that other area, or is that a one-time certification of the project area, without revisiting it?

THE WITNESS: I think you could certify the south half of the project and come back, and leave the north half of the project area available for subsequent certification under Section G of 729(A)(3).

Q. (BY MR. STOVALL) Again, you're talking positive production response certification and not project certification?

A. Yes, I am.

CHAIRMAN LEMAY: Section G?

THE WITNESS: Section G of 729(A)(3). "The recovered oil tax rate shall apply only to the crude oil produced from the area the Division certifies to be affected by the enhanced recovery project or expansion."

CHAIRMAN LEMAY: You have the bill and not the--

THE WITNESS: I have the bill, actually.

CHAIRMAN LEMAY: Additional questions of the witness?

MR. STOVALL: Yes.

Q. (BY MR. STOVALL) I would like to go back and discuss some of the things we covered before. Again, we're getting a little bit beyond the scope of the Oxy thing, but I think they are very relevant questions.

Number one, reading that statute, we talked earlier with Mr. Foppiano about, what if we find a response outside the project area, your interpretation would be that cannot qualify, is that correct?

A. It's not within a project area that's been certified, and I think to the extent we think you ought to honor project areas, we ought to do the same.

Q. Second question, and this may kind of, actually, help resolve it. You probably know, and I know Mr. Foppiano knows, that I have taken the approach, on behalf of the Division, that when you come in for a project expansion approval, it cannot qualify for the incentive tax rate if that expansion is done under an order that was issued before the effective date of the Act.

That was the approval of the project that qualified, and in order to qualify, you must come in and get a new approval from the Division subsequent to the effective date of the Act.

Now, I guess the approval that I suggest that the statute is looking for is not some unique EOR approval, but really an approval of a waterflood project, and that may be the key to the answer to this question is, when you come in, I think the Act anticipates that it will be an approval which is already done prior to the time of this Act.

The Division approves waterflood projects, and it's when the Division approved that waterflood project, and once you approve the project you're really authorizing the injection of water, in the case of a waterflood--or whatever other second project--and you've defined the area at that time, because that's where the operator can conduct the operations under that authority?

Does that make sense to you, Mr. Carr?

Do you follow me?

A. If I understand the question, the Act and the rule provides that any application for enhanced oil recovery project, under the Act, filed prior to March 6, 1992, it talks about, those applications cannot be considered.

But the testimony from Representative Whitaker, and I think the statute provides, that within an old waterflood project, you may have a new EOR project approved if, in fact, you meet the other test of a substantial change in the method used to achieve the displacement of oil in the defined project area.

Q. It seems to me, in the expansions, as I would interpret that, you do two things: You come in and get the project approved under the conservation regulatory scheme of the Division who say, yes, you can put fluids into the reservoir for enhanced recovery purposes?

A. Right.

Q. And then the second part of that says, in the case of these expansions, we will look and say, there's a little extra piece tagged on to that process to say, in the case of an expansion only, to say, is this an expansion? Would you agree with that?

A. Yes, either geographic or because of some significant change, I think the phrase is.

Q. Significant change of process or something?

A. Or modification in the process used to displace oil.

Q. Now the intent, you had talked earlier about the actual injection of water, and again, from the Division's standpoint I think we have used that, not for the ability of the project to qualify, as not being that date, but rather to start the clock running on the time period in which a positive production response is received?

A. Correct.

Q. Now, going back to what we're doing, and kind of putting all that together, I think what I have just said may lend some support to Mr. Foppiano's argument that, if we approve a project area for the purpose of injection of fluids for secondary recovery, that defines the area for the EOR project, because that's really the approval that the statute is looking for, is that correct?

A. That's right.

Q. Which then raises the question about, well, what if certain portions of that project area don't show any sort of response? Mr. Foppiano's argument is, well, once you've approved that project area, you've defined it. Either you've got a positive production response or you don't, within the project area.

You and I, a little earlier, have previously said, well, if a particular area doesn't qualify, we can reduce the project area for tax credit purposes, and I'm not sure that that's true. And, once again, I would say that's a question we need guidance from the Commission on, on that issue.

Do you concur, as a brilliant attorney on the witness stand, are you able to support that?

A. I didn't know Mr. Kellahin was testifying, but, yes.

MR. KELLAHIN: I object to counsel badgering my witness.

Q. Okay. That leaves me in the position of where I think the Division needs some guidance, and I guess what I would say at this point is, if that is the case, then the Division would then have to look much more critically at the project area it approves at the time of the project approval, because it would not have a second chance to come back and look at that area in terms of secondary--of positive production response.

If we follow that line of reasoning, once we approve, then, secondary production, if Mr. Foppiano is correct, then it is for the project area. So that will be helpful to the Examiners to know what they've got to look at, the first time.

A. The only thing I would say in response to that is, the units that come before you differ tremendously in size and in just the nature of the project, and I think that you, as a Commission and a Division, have been asked to use your expertise to evaluate these consistent with the purpose of the Act, and that is to give this incentive if it meets the tests of that statute.

We're getting to a point in the development of the whole history of this incentive, where some guidance would be important to the industry, I think.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

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

Mr. Kellahin, I would love to have a draft order on this to send out to all Commissioners, if you wouldn't mind.

Anything additional?

MR. KELLAHIN: Just a brief comment to conclude the process. We appreciate the opportunity to air our concerns about the whole process, but specifically there's a two-part process.

We have a certification of a project area. Subsequently, within a five-year period, we come back for certification of a positive response. Our concern with this order is that Examiner Catanach has prematurely made a judgment about the project area and disqualified our project area, at least half of it, because there were five existing oil wells in it. We find no basis for doing that.

The scientific testimony by Mr. Gengler, the SPE paper, the engineering report by Scott Hickman's group, indicate that the substantial change in process is the reduction from 80 to 40 acres, which can occur with or without the drilling of the additional wells. We think that proof is sufficient enough to have certification for the project area. It then becomes our obligation to show, at some future date, a positive injection response at another hearing, if the Division so requires.

So, my concern is they've prematurely denied us the qualification of a project area that we think deserves at least a certification as a project area. We believe it is treatment inconsistent with how others have recently been treated, and we think the order is satisfactory for what we want to do, provided the Commission will modify the project area and put back in five wells that were excluded.

I'll be more than happy to draft a proposed Commission order.

CHAIRMAN LEMAY: Anything else in the case?

If not, we'll take the case under advisement.

(And the proceedings concluded.)

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL March 2, 1994.

Carla Diane Rodriguez

CARLA DIANE RODRIGUEZ, RPR
CSR No. 4

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

CASE NOS. 10,771, 10,345, 10,346, 10,772,
10,823, 10,788 and 10,790

CONTINUED AND DISMISSED CASES

TRANSCRIPT OF PROCEEDINGS

ORIGINAL

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

FEB 1 1 1994

January 13, 1994

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on January 13, 1994, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

WHEREUPON, the following proceedings were had at 9:02 a.m.:

CHAIRMAN LEMAY: Good morning, happy new year. This is the Oil Conservation Commission, and my name is Bill LeMay, I'm chairman.

To my left is Commissioner Bill Weiss, to my right Commissioner Jami Bailey, representing the Commissioner of Public Lands, State of New Mexico.

We will start by calling Cases 10,345 and 10,346, Louise Locke.

MR. STOVALL: Applications of Louise Locke to consider objections to well costs, San Juan County, New Mexico.

Mr. Bruce, as I understand, Louise Locke has recently received the well cost information and has requested some additional time to audit the information before this case goes forward; is that correct?

MR. BRUCE: Yes, Mr. Tully requested some extra time, and we have no objection on behalf of BHP.

CHAIRMAN LEMAY: Thank you. Without objection, those cases will be continued to the -- I have March 10th docket.

* * *

CHAIRMAN LEMAY: And call Case Number 10,772, Barber Oil. I'm jumping on you here, Counselor.

MR. STOVALL: Application of Barber Oil, Inc., for saltwater disposal, Eddy County, New Mexico.

Applicant has requested this case be continued to the February 10th docket.

CHAIRMAN LEMAY: Without objection, that case will be continued to the February 10th docket.

* * *

CHAIRMAN LEMAY: And call Case Number 10,771.

MR. STOVALL: Application of OXY USA, Inc., to authorize the expansion of a portion of its Skelly Penrose "B" Unit Waterflood Project and qualify said expansion for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, Lea County, New Mexico.

Applicant has requested that case be continued to the February 10th docket.

CHAIRMAN LEMAY: Is there any objection? If not, that case will be continued to the February 10th docket.

* * *

CHAIRMAN LEMAY: And we will now call Cases 10,823, 10,788 and 10,790.

MR. STOVALL: Mr. Chairman, I think there's a --

CHAIRMAN LEMAY: I'm sorry.

MR. STOVALL: -- different procedural matter on -- We can do them, but I think we need to --

CHAIRMAN LEMAY: Separate them.

MR. STOVALL: -- do them individually, yeah.

CHAIRMAN LEMAY: Yeah, okay.

MR. STOVALL: 10,823 is the Application of Nearburg Producing Company for compulsory pooling, Eddy County, New Mexico.

Applicant Nearburg Producing has requested this case be continued to the February 10th, 1994, docket.

CHAIRMAN LEMAY: Is there any objection to that? If not, Case 10,823 will be continued to the February 10th docket.

* * *

CHAIRMAN LEMAY: And we will call Cases 10,788 and 10,790.

MR. STOVALL: 10,788 is the Application of Nearburg Producing Company for compulsory pooling, Eddy County, New Mexico.

Case 10,790 is the Application of Yates Petroleum Corporation for compulsory pooling, Eddy County, New Mexico.

These are competing force-pooling applications, and I understand there's been an agreement reached.

MR. CARROLL: That's correct. Mr. Chairman, with respect to Yates's Case 10,790 --

MR. STOVALL: Excuse me, Mr. Carroll, do you want to go ahead and enter your appearance for the record?

MR. CARROLL: I'm sorry, I'm Ernest Carroll of the Losey law firm of Artesia, New Mexico, appearing on behalf of Yates Petroleum, the Applicant in Case 10,790.

MR. BRUCE: And Jim Bruce from the Hinkle law firm in Santa Fe, representing Nearburg Producing Company, the Applicant in Case 10,788.

CHAIRMAN LEMAY: Thank you. Are there additional appearances in these cases?

Okay, Mr. Carroll?

MR. CARROLL: Mr. LeMay, Yates Petroleum, with respect to the case in which it is the Applicant, 10,790, at this time would move to dismiss its Application, or its Application for a *de novo* hearing with respect to that Application filed, and would further advise that with respect -- in conjunction -- both cases, Yates Petroleum and Nearburg Producing Company have reached an agreement whereby Yates has elected to participate in the drilling of the Nearburg well in Section 2.

We have signed an AFE and returned it, and it is my understanding Nearburg will agree and stipulate on the record that such AFE was timely submitted with respect to the Order.

And furthermore, the only other thing that Yates would like to note, at this point in time the well, by order of the Commission, is scheduled to be drilled by

February 1.

Yates would like to put a record. We don't know if there's going to be a problem, but we want to put a record that we expect a well to be spudded on or before February 1 and would oppose any further extension.

CHAIRMAN LEMAY: Mr. Bruce?

MR. BRUCE: Mr. Chairman, on behalf of Nearburg, we stipulate that Yates has timely elected to join in Nearburg's proposed well, in other words, without a risk penalty.

We would request that an order be entered in this case, reflecting this stipulation, because no operating agreement has yet been signed by the parties. So we want that to protect Yates and to protect Nearburg.

There is currently a February 1, 1994, commencement deadline. Yates does oppose any extension of that.

Nearburg is in the process of obtaining a contract on a drilling rig. It would like a two- to four-week extension of that. It does plan to commence its dirt work this month.

We hope to spud it by the end of the month, but to be safe we would like to have an extension of two to four weeks. But Nearburg does commit that it will take the steps necessary to preserve Yates' lease, which is -- If drilling is not commenced, obviously, it will expire.

CHAIRMAN LEMAY: Let me ask you, does Yates have a spudder on that state lease to spud it?

MR. CARROLL: Yes. Yes, sir, we do. We've had it out there for quite some time now, and that's the main reason we have an objection.

I would suggest that the proper thing is that a formal application be made. I don't know if our clients can work this matter out. And there may not be a problem, because there's not much activity going on down there, and I think there are some rigs available. And we do have more than two weeks, you know, available to get a well spudded.

So I would think the proper way would be to make a formal application, and let's see what happens, and we'll determine --

CHAIRMAN LEMAY: How much is your spudder costing you? Do you know?

MR. CARROLL: What's the spudder run, Randy? I'm not sure?

FROM THE FLOOR: I really don't recall. I just --

MR. CARROLL: I'm sorry, Mr. LeMay, I don't have that.

CHAIRMAN LEMAY: That's all right. Would it be appropriate to have that part of the cost of the total well, do you think, in the event that Nearburg couldn't get a rig on location by February 1?

MR. CARROLL: I think that that might be a very appropriate remedy, or some extension that Nearburg would have to reimburse any costs that were out.

CHAIRMAN LEMAY: Maybe not reimburse, but that's just the cost of doing the well and share in proportion your interest in the proration unit.

MR. CARROLL: That's correct, that could be a solution, yes, sir.

CHAIRMAN LEMAY: I mean, I realize that rigs, you just always can't get them when you want them, but I understand if you're going to do the dirt work that Nearburg -- Does he have a contractor, do you know?

MR. BRUCE: I'm not certain, Mr. Chairman. They did indicate to me on the phone yesterday that they would be starting the dirt work by the end of the month, but they are in the process -- What he indicated was that he did not have a drilling rig under contract yet.

CHAIRMAN LEMAY: You might check on that as a possible stipulation in the event the well is not started by February 1 and there needs to be additional extension to any cost of that cable tool to save that lease will be part of the bill of the well you're going to drill.

MR. BRUCE: Total well costs.

CHAIRMAN LEMAY: Total well costs.

MR. BRUCE: Thank you, Mr. Examiner.

CHAIRMAN LEMAY: Thank you, gentlemen. Anything else in this case?

MR. STOVALL: Clarify one thing just to make sure.

This well -- Is your position and part of the stipulation, this well is being drilled under the force-pooling order, not in lieu of the force- -- not -- based on agreement which voids the force-pooling order?

MR. BRUCE: It's being drilled under the force-pooling order as of this -- And if they do sign an operating agreement, we will let the Commission know immediately.

MR. CARROLL: That's all I have.

CHAIRMAN LEMAY: Thank you, Mr. Carroll. Thank you, Mr. Bruce.

* * *

(Thereupon, these proceedings were concluded at 9:12 a.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 January 18, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

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:) CASE NO. 10771

APPLICATION OF OXY USA Inc.

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: William R. LeMay, Chairman
Gary Carlson, Commissioner
Bill Weiss, Commissioner
Florene Davidson, Senior Staff Specialist

November 10, 1993

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on November 10, 1993, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Deborah O'Bine, RPR, Certified Court Reporter No. 63, for the State of New Mexico.

ORIGINAL

CHAIRMAN LeMAY: In case there is someone here waiting for the Oxy case, we're not going to hear that. We can go on the record and say that case will be continued until January 13th.

CERTIFICATE OF REPORTER

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

I, Deborah O'Bine, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that I caused my notes to be transcribed under my personal supervision, and that the foregoing transcript is a true and accurate record of the proceedings of said hearing.

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 12, 1993.

Deborah O'Bine

DEBORAH O'BINE
CCR No. 63

OFFICIAL SEAL
Deborah O'Bine
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: Sept. 19, 1994