STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

APPLICATION OF CONOCO, INC., FOR A PRESSURE MAINTENANCE PROJECT AND TO QUALIFY FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE NEW MEXICO ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO

CASE NO. 11,779

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

May 29th, 1997

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, May 29th, 1997, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

May 29th, 1997
Examiner Hearing
CASE NO. 11,779

* * *

E X H I B I T S

* * *

A P P E A R A N C E S

FOR THE DIVISION:

RAND L. CARROLL
Attorney at Law
Legal Counsel to the Division
2040 South Pacheco
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

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

* * *

WHEREUPON, the following proceedings were had at 8:18 a.m.:

EXAMINER STOGNER: At this time I will call Case Number 11,779.

MR. CARROLL: Application of Conoco, Inc., for a pressure maintenance project and to qualify for the Recovered Oil Tax Rate pursuant to New Mexico Enhanced Oil Recovery Act, Lea County, New Mexico.

EXAMINER STOGNER: Call for appearances.

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

EXAMINER STOGNER: Any other appearances?

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

<u>RAY HINCHCLIFF</u>,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. Ray Hinchcliff, staff engineer for Conoco.

Q. Mr. Hinchcliff, have you testified before the Division on any prior occasion?
A. No, sir.
Q. Summarize for us your education.
A. BS degree in petroleum engineering, University of Wyoming, 1985.
Q. Summarize for us your employment experience.
A. I worked for Conoco for 12 years, Gulf Coast, North Sea and here in New Mexico, Lea County.
Q. Summarize for me what your responsibilities are for that portion of the operations in Section 36 that's the subject of this Application.
A. It's a pressure maintenance project to inject water into the ground to -- in charge -- add additional reservoir pressure.
Q. And is that a subject you've studied on behalf of your company?
A. Yes, sir.
Q. And is this Application your responsibility?
A. Yes, sir.
Q. Are the details that were compiled and submitted to the Commission -- or the Division -- on the Division Form C-108 information that you reviewed and tabulated?
A. Yes, sir.
Q. For the underground injection control compliance?

A. Yes, sir.

MR. KELLAHIN: All right. We tender, Mr. Examiner, Mr. Hinchcliff as an expert petroleum engineer.

EXAMINER STOGNER: Mr. Hinchcliff is so qualified.

Q. (By Mr. Kellahin) Let me have you turn to the first display. Let's orient the Examiner as to the area, and let's first talk about the pool. What pool are you in?

A. North Hardy-Tubb-Drinkard Pool.

Q. And is there an outline on this display that shows the boundary of that pool?

A. Yes, sir, it's in green.

Q. Within that area, have there been area have there been wells drilled that produce from this pool?

A. Yes, sir, there's presently been five wells that's been drilled and completed and producing in that pool at present.

Q. And how are they illustrated on this display?

A. They're illustrated four in an orange-type red dot, 18, 19, 4 and 2; and one, number 3, is our proposed injector.

Q. All right, that currently is a producer that would be converted to injection with the approval of the Division?

A. That's correct.

Q. This display only shows those wells in the pool and has excluded all the other wells in the area?

A. That's correct.

Q. And when we look at the C-108, we can see the other wells?

A. That's correct.

Q. All right. Describe for me what you are proposing for the project area.

A. The project area is outlined in black. It's a 240-acre outlined area that we would like to inject water to recharge the reservoir.

Q. Are there any Tubb or Drinkard wells that are producing in the immediate vicinity, other than those shown on this display?

A. No, sir.

Q. Lynx is shown as an interest owner and was provided notice of this hearing. What is their interest?

A. Conoco sold the Hardy 36 State lease interest from 3900 feet to surface to Lynx Petroleum, and they presently operate a shallow waterflood.

Q. Okay. The pressure-maintenance project area in the Application proposes injection authority for an interval described as 6423 feet down to 6593 feet?

A. Correct.

Q. Do you have displays that illustrate that vertical interval?

A. Yes, we do.

Q. And what would that interval consist of? Is that the limits of the pool?

A. That's the existing limits of the pool, right.

Q. Okay. Based upon your conclusions and study of the project, what have you determined is a forecast of the additional oil that may be recovered with the approval of this project?

A. The additional oil we estimate to be approximately 131,000 more barrels.

Q. Describe for me why you have chosen the Number 3 well as the injection well.

A. Primarily because of its location. It's centrally located. We can use it to provide pressure support to the other four wells.

Q. Give us a summary, Mr. Hinchcliff, of your analysis of why you think this is a viable opportunity for a pressure maintenance project.

A. The wells were originally completed in the Tubb, pressure decrease has been significant from original reservoir pressure of approximately 2300 pounds down to its present limit of about 850. Production has dramatically fallen off, and we believe that by injecting water in the Number 3 we can recharge the reservoir, which will arrest our decline and result in an additional recovery of crude oil.

Q. Of the five wells in the pool, what is the approximate age or vintage of these wells?

A. Ninety- -- The exhibit's got dates. 1995, 1994 and 1996 vintage.

Q. When the wells were initially potentialed, what kind of daily oil rate did they achieve?

A. Average of about 110 barrels a day.

Q. And on average, what are these wells now doing?

A. Oh, about 13 to 14 barrels a day.

Q. And is there water produced in association with the oil?

A. Yes, sir.

Q. The conclusion, then, is with the conversion of one of these wells to injection, it will be a way to increase reservoir pressure; that's the primary objective. And with doing that, then, you expect to increase ultimate oil recovery.

A. That's correct.

Q. Let's go into the specifics of the project. If you'll turn to Exhibit Number 2, identify and describe what we're seeing on this display.

A. Number 2 lists the five wells that we plan in the project.

The first well is the Number 3, which we plan to convert to injection. It's presently completed in both the Tubb and Drinkard.

The other four wells, the 2, 4, 18 and 19, are our producing wells or proposed wells. All of those are presently in the Tubb. The Number 2 well is also completed in the Drinkard.

Q. Okay. Let's turn to Exhibit 3 and have you identify this display. What are you looking at here?

A. Exhibit 3 is the top Tubb marker structure map, mapped on TVD subsea. It shows the North Hardy-Tubb-Drinkard wells on production, which are the 2, 4, 18, 19, and the Number 3 is also on production at present.

We have listed four other wells, 7, 21, 15 and Number 1 as penetrations through the Drinkard and Tubb -- they are presently not completed in those reservoirs -- to give a better description of the outline of the reservoir.

And we also have indicated a cross-section we have prepared going from 2, 4, 3 and 18, and then the 240-acre project area.

Q. Based upon your engineering study, is there a geologic component of this reservoir, based upon structure, that would be affected by this project?

A. No, sir.

Q. So the location and the selection of the injection well is not affected by a structural position?

A. No, sir.

Q. Okay. What has caused you to propose this as the project area? What explains this boundary?

A. It's defined by the existing wells we have on production right now that we would like to provide support to.

Q. There's an open location in the southeastern portion of the project area. In your opinion, is it now reasonably probable to drill another producing well in that area, in the absence of pressure maintenance?

A. At present, no. We -- Wells are not economic unless we can recharge the reservoir.

Q. Okay. Let's turn to the type log. If you'll look at Exhibit 4, let's identify the reservoir more specifically. The pool limits we identified earlier, let's do it on this display. We need to find the top of the pool at 6423. Can we do that on this log?

A. Yes, sir, the 6423 is the top perforation on this log, indicated in red.

Q. Okay. And above that, then, you don't see an opportunity to produce hydrocarbons in this formation or in this pool?

A. No, above that the formation doesn't have the reservoir quality to be productive.

Q. And then as we move down vertically and get to approximately 6593, that represents the bottom limit of the pool?

A. On the Tubb portion of the pool, yes.

Q. The Tubb and the Drinkard have been combined by previous order of the Division into one pool?

A. That's correct.

Q. When we look at the target interval, you're seeking authority to have the project area be the entire pool, but you have specifically targeted in the injection well a certain portion of the Tubb?

A. Yes, the area indicated on the type log "Target Injection Zone" is what we believe to be the better quality of the reservoir, and this is the area we believe will be the area that we'll have the most success in injecting our water.

Q. In order to have the greatest opportunity, then, to efficiently inject water into that portion of the pool which will provide you the greatest potential for pressure increase --

A. Yes, sir.

Q. -- is this the place?

A. Yes, sir.

Q. Okay. And how did you select that?

A. Based on our log data, core data and offset production data and production logging, we have a fairly good idea that this is the area that we're producing approximately 80 to 85 percent of our production out of the Tubb at present, out of this 75-foot interval that stretches from about 6420 to about 6500 feet.

Q. Okay. All right, let's go to the cross-section now. I'm sorry, you've got a display before we get to that. Let's look at 5, which is your summary of reservoir data. Explain that exhibit to us.

A. This is just a summary of the Tubb formation, listing the various fluid parameters of the reservoir and the reservoir data.

The reservoir pressure, the 2325 was the original pressure. At present it's approximately 850 pounds. Recently we took a survey in the Number 4 well in April to verify that.

Average permeabilities were gathered from core data and pressure buildup data. The information here is quite complete.

Q. All right, let's turn to Exhibit 6 and look at the cross-section. When you look at that perforated interval or that portion of the pool that is targeted for injection, can you correlate that interval --

A. Yes, sir.

Q. -- among and between all the wells in the pool?

A. Yes, sir, you can. It correlates very well.

Q. Does it appear that the injection well will provide you an effective and efficient means to communicate pressure with the other wells?

A. Yes, we believe that the injection well will communicate to the other four wells.

Q. Okay. When we look at the schematic in a minute for the injection well, we're going to see exactly how you propose to recomplete it for injection. Currently the injection is producing -- proposed injection well is producing how many barrels of oil and water?

A. Presently, the Number 3 well, our proposed injector, six barrels of oil a day, 10 barrels of water and 245 MCF gas.

Q. When you recomplete this for injection, are you going to do anything other than simply convert it for injection?

A. We are going to isolate the Drinkard by setting a cast-iron bridge plug and putting the required footage of cement on top of it.

Q. Again, that's an effort to do what, then?

A. Our effort is to minim- -- is to prevent any water going into the Drinkard formation.

Q. And that will give you an opportunity to pressure up this portion of the Tubb zone?

A. That's correct.

Q. Okay. Let's turn to see how you have analyzed the opportunity for increased oil recovery and look at the specifics. If you'll turn with me to Exhibit 7, what are we looking at in this display?

A. Exhibit 7 has four curves. The one in the black squares is production without water injection as we predict it. The --

Q. All right, let's start with that curve.

A. Okay.

Q. Its beginning point is about 95, and it is in the upper left-hand corner of the plot?

A. That's correct.

Q. That's a composition of production from how many wells?

A. That's from all five production wells.

Q. Okay. And as you follow that curve down, it intersects with a point where other curves come through --

A. That's correct.

Q. -- and then continues on a decline where you have a black line and black dots?

A. Yes, it terminates in the year 2008.

Q. All right. What is your analysis of that? What does that mean?

A. Basically, 2008 is our economic limit we have set at Conoco, and that's the decline we have estimated the reservoir will have without pressure maintenance.

Q. Correspondingly, there's a curve that shows the accumulation or cumulative oil production forecasted over time for those same wells without pressure support?

A. That's the curve with the solid triangles, black triangles. And we have accumulated approximately 116,000 barrels through the end of 1996, and we project that to be about 262,000 barrels at the time of economic limit.

Q. Okay. How did you approach the analysis that got you to the conclusion that increasing the pressure was going to generate additional oil recovery? What was your method?

A. Our method was based on just sound reservoir principles. We -- At present, the decline in the Tubb is, on an average, between now and the time we reach economic limit, it's approximately 12.8 percent. And we feel by injecting water we can arrest that to an average of about 7.7 percent, which will result in the additional oil recovery.

Q. How did you determine what volume of water to inject over what period of time?

A. We used the pressure limitation as our driving factor, and from that we came up with the decline -- or I mean an injection schedule, to fill the reservoir back up.

Q. You're referring to the Division guideline of a surface pressure limitation based upon depth using .2 p.s.i. per foot of depth?

A. That's correct.

Q. And you've generated a volume of water that would keep you within that pressure limit?

A. That's correct.

Q. And using engineering analysis, then, you've developed a schedule for injection?

A. That's correct.

Q. Let's look at that schedule. It's Exhibit 8.

As water is injected, then, you have calculated a certain quantity of additional oil to be produced?

A. Yes, we --

Q. Let's finish the curves, then, on Exhibit 7 and show you how you have forecasted an extension in the producing life of the wells and, correspondingly, an increase in the ultimate oil recovery.

A. Yes, we -- We have concluded that by the injection water we can effectively arrest the decline from about 12.8 percent to 7.7 percent, on average, and that new decline is shown in the triangles, the gray triangles. The square -- The squares that are filled in indicates the reserves that we project from the project with an additional approximately 131,000 barrels from pressure maintenance.

Q. Okay. When we look on Exhibit 8, what are we seeing here?

A. Exhibit 8 is just the hard data that went into the -- support the Exhibit Number 7. There's six columns and the years.

The first column is production of barrels per year without water injection and the cum barrels without water injection.

The third and fourth column are -- or the fourth and fifth column, excuse me, are the production with water and cums with water injection. And then the delta oil, and delta oil is in barrels of oil per year and barrels of oil per day.

Q. Okay, let's turn to the subject of information contained on the Division Form C-108 -- it's marked as Exhibit 9 -- and let's start by having you turn to the last page of Exhibit 9, which shows the area of review map. Do you have a copy of that?

The two-mile radius on the map shows all the wells in the area, regardless of depth?

A. Yes, sir.

Q. And then within the half-mile area of review, you've analyzed the data from all those wells, have you?

A. Yes, sir.

Q. The Division looks for problem wells, which are wells that may be inadequately cemented or cased across the approved injection intervals. Do you find any of those kinds of wells?

A. No, we do not have any problem wells.

Q. Did you tabulate for the Division and supply either the measured or the calculated cement tops of all the producing wells within the area of review?

A. Yes, we have.

Q. Were all those measured tops of cement with the exception of one well?

A. Yes, all of them excepting the one.

Q. With the one that was a calculated top of cement, what was your method for making that calculation?

A. Our method was, we used the bit size, calculated our hole volume and used our casing to come up with the annular volume. We -- From that, knowing the volume of cement we pumped and the yield from the sacks of cement, we came up with estimated volume of cement, and on our Application we --

Q. Let's find the right page. We're looking at the fourth page down in the C-108? There's a table, right?

A. That's correct.

Q. All right, it's the last well on the table, is it not?

A. Yes, Well Number 19.
Q. Tell me what your calculation was.
A. Our calculation was -- As I mentioned, we used the hole volume from the bit and the annular volume from the casing, and we calculated the volume that was between the two, using the yields and the number of sacks of cement we pumped.
We came up with a cement top of 2210 feet. That's based on an 80-percent efficiency or an 80-percent fill-up. If you use a 50-percent fill-up, that gets you to a cement top of 3992, approximately 2500 feet above our average injection target.
Q. Have you also determined that all the wells in the area of review have sufficient surface casing strings and cement to protect any freshwater sources?
A. Yes, sir.
Q. What is your opinion of the depth and the source of any freshwater source?
A. Our opinion is that it's protected from our existing wells.
Q. And is this the Ogallala formation?
A. Yes, it's the Ogallala formation.
Q. It is found at approximately what depth in this area?
A. Approximately 200 feet.

Q. Have you supplied the Division with an analysis of any freshwater sources in this vicinity?

A. Yes, Conoco operates two freshwater wells in adjacent Section 35.

Q. When we go to the last portion of Exhibit 9, the area of review, can you show us the approximate location of the freshwater wells?

A. Yes, they're located in Location I and P of Section 35.

Q. Okay. You said Conoco drilled those wells. Who uses them and for what purposes?

A. Conoco uses those for fresh water for drilling mud -- using to make up drilling mud or for operations in the field and things of that nature.

Q. Okay. All right, let's turn to the third page of the Exhibit 9 and look at the schematic of the proposed injection well. It's been reduced as to scale and some of these numbers are perhaps hard to read, but give us a summary, then, on this display of what you're proposing to do.

A. Our proposal is to remove all the production equipment downhole, the rods and pump and tubing, and set a bridge plug and isolate it with cement on top of the bridge plug to isolate the Drinkard formation from the Tubb, and then run back in the hole with a packer and tubing to convey the water into the Tubb formation.

Q. What is to be the source of the injection water?

A. The source is the produced water from the lease.

Q. And from what formation or formations does that water produce?

A. The water right now is coming from the Tubb, Drinkard and McKee formations.

Q. Are all those waters compatible for purposes of injection into the proposed target interval?

A. Yes, they are.

Q. And you have provided an analysis for the Division?

A. No, sir, we haven't.

Q. But you do have compatibility --

A. We do have compatibility tests. We could provide them at a later date if they so wished.

Q. All right. Are you aware of any objection to the approval of the Application?

A. No.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mr. Hinchcliff.

In addition, Exhibit 10 is a newspaper notification of the request.

And then finally Exhibit 11 is my affidavit of notification. I am aware of no objection.

With your permission, then, we would seek the introduction of Conoco's Exhibits 1 through 11.

EXAMINER STOGNER: What was your list of notification? Was that just the paper?

MR. KELLAHIN: No, sir, there should be an Exhibit 11. Here it is.

EXAMINER STOGNER: Exhibits 1 through 11 will be admitted into evidence at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. Let's see, Mr. Hinchcliff, you said that the source water was going to be the -- essentially reinjection into the produced water?

A. That's correct.

Q. Is that going to be sufficient throughout the life of this proposed project?

A. Yes, at present the lease produces approximately 500 to 550 barrels of water a day, and we have additional McKee wells that will come on line, that will provide us even more water production.

Q. And where are those key wells that you mentioned?

A. Those McKee wells are on the structure map, which is Exhibits Number 3 -- We presently have the Number 1 and Number 21 on production, and those two wells provide about the 550 barrels of fluid a day of water, and the Number 15 is scheduled to come on production in June.

Q. Now, the McKee out there is -- What's the approximate depth of that?

A. Approximately 10,000 feet.

Q. 10,000. And what's the water volumes coming off of the current producers now?

A. At present we make 19 barrels of fluid a day -- I mean, excuse me, 19 barrels of water a day from the five producers.

EXAMINER STOGNER: Mr. Kellahin, subsequent to today's hearing could you provide the compatibility --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: -- test out there in this area for the complete record?

MR. KELLAHIN: Yes, sir.

Q. (By Examiner Stogner) Okay, are all the water source wells -- are they going to be tied in with a pipeline running over to the 3? Is that the way you look at it at this point?

A. The present setup is that all the wells going to the Hardy battery where the water is commingled, and from that point we will take a common line back to Number 3.

Q. Where is that battery at?

A. The battery is located adjacent to the Number 1 well.

Q. So essentially in the center of the section?

A. That's correct, sir. In fact, we plan on using the existing production flow line from the Number 3 to the battery as our water injection line.

Q. Okay, now, will the water be pressured up at the battery site, or do you propose to pressure it up at the well site?

A. It will be pressured up at the battery.

Q. Okay. Did you do a cost analysis of the cost of this -- of the proposed conversion and the -- any other facilities that are going to be needed?

A. Yes, we have. We estimate the cost to be in the $35,000 to $40,000 range.

Q. And what all would that entail?

A. That will entail installing the injection pump, the well work needed on the Number 3 well, and some automation in our existing water system.

Q. Explain that automation a little bit more.

A. The automation is basically to make sure that we don't -- we protect the pump, the surface injection pump, tie it into the water tank, and also it will be used to meter the amount of water that we put into the ground.

Q. Are there going to be any work necessary on the current producing wells, 18, 19, 2 and 4?

A. No, sir, we plan on no additional work on those wells.

Q. When do you foresee a drilling of an additional fifth well down in that far southeastern corner of the project?

A. If we see a positive response from the pressure, such that the Number 3 provides the water support to the 19 and Number 4, I would envision us going ahead with the proposal to drill a fifth producer in that corner.

Q. What kind of response would you have to see before that decision would be made?

A. Well, we are projecting we will have fill-up in approximately a year and a half. And I would anticipate in that period of time we would have sufficient pressure data to support either drilling an additional well or not drilling an additional well.

Q. What would the cost of such a well be?

A. At present cost, approximately $380,000.

Q. You don't foresee the need of any makeup water being utilized?

A. Not at this time, no, sir.

Q. How about at a later date or in the future?

A. No, the McKee wells are projected to have a life similar to what we project for the Tubb.

Q. Okay. No possibility of utilizing fresh water, or are you going to stay with produced water?

A. We prefer to stay with produced water.
Q. Will there be any treating necessary for the reinjection of that water?
A. Yes, we will probably utilize some scale inhibitors.
Q. The tubing that you're -- that will be utilized, will that be a plastic- or cement-coated tubing?
A. We have had success with running a -- luck -- coated tubing, plastic-coated tubing.
Q. What kind of coating?
A. Plastic-coated tubing.
Q. Well, what did you say before that? It sounded like a product, a Luck or something?
A. No, I -- You may have just misunderstood me.
Q. Oh, I'm sorry, I'm sorry. So that's a -- So you're running a plastic --
A. We've had some -- I said, We've had some good luck with running plastic-coated --
Q. Oh, I'm sorry --
A. -- tubing.
Q. -- okay. You've had good luck with running plastic-coated tubing, okay.
Okay, what is the producing interval directly above your Tubb producer?
A. The stratigraphic column above the Tubb is the

Blinebry.

At present we have no Blinebry production in the Hardy 36 State area. The Tubb marker is the base -- basically the base of the Blinebry.

Q. Okay, what are the most of the -- When I refer to your area-of-review map, there are quite a few wells within the half-mile radius, and what are those producing?

A. Okay, the wells on that map that are labeled EHU are the Eumont Hardy Unit, which is -- it's an ex-Conoco waterflood unit that we sold to Lynx. It's presently in the Penrose. It's basically in the 3750-to-3850-foot range.

Q. So that's the Eumont, and they're all oil and being -- Are they still being flooded at this time?

A. They're still being flooded. There are some inactive and active wells in that unit.

Q. When I look in the far northwest quarter, northwest quarter, Section 36, you have an EHU well that is a designated gas well.

Is that in the Eumont Gas Pool, outside the waterflood area that you know? Or do you know anything about that well?

A. I couldn't give you an accurate answer on that, sir.

Q. Okay.

A. The -- I can tell you that the Eumont-Penrose interval, as you move to the northeast, you get into a gas cap, and as you move to the southeast you get into an oil rim.

Basically the waterflood's in the oil rim, so I would assume that Number 9 is probably close to that oil rim boundary.

Q. Do you know if that one is a Lynx Petroleum well also?

A. It's a Lynx Petroleum well. All the wells that are indicated EHU are operated by Lynx.

Q. So within that area of review, there are no plugged wells?

A. No, sir, at present there are no plugged wells.

EXAMINER STOGNER: Okay. Does anybody else have any questions of this witness?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Mr. Kellahin, is there anything I've forgotten as far as the enhanced-oil-recovery portion of this?

MR. KELLAHIN: No, sir, I think you have it covered.

EXAMINER STOGNER: Does anybody else have any questions?

THE WITNESS: Thank you, sir.

EXAMINER STOGNER: You may be excused.

Do you have anything further, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: I'll hold the record open pending the compatibility data for the water, and at this time we'll move on.

(Thereupon, these proceedings were concluded at 8:58 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11779, heard by me on 29 May 1997.

_______________, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL June 2nd, 1997.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998