STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO

9 September 1987

EXAMINER HEARING

IN THE MATTER OF:

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| Application of Pelto Oil Company for statutory unitization, Chaves County, New Mexico. | CASE 9210 |
| and | |
| Application of Pelto Oil Company for a waterflood project, Chaves County, New Mexico. | CASE 9211 |

BEFORE: Michael E. Stogner, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division:

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# I N D E X



# E X H I B I T S

## E X H I B I T S

E X H I B I T S CONT"D

MR. STOGNER: Call next Case Number 9210.

MR. TAYLOR: The application of Pelto Oil Company for statutory unitization, Chaves County, New Mexico.

MR. STOGNER: Call for appearances?

MR. BRUCE: Mr. Examiner, my name is Jim Bruce, from the Hinkle Law Firm in Santa Fe, representing the applicant.

At this time I'd request that this case be combined with Case 9211.

MR. STOGNER: Let me get this straight, Mr. Bruce, you want this consolidated with Case 9211?

MR. BRUCE: That's correct.

MR. STOGNER: At this time we'll call Case Number 9211.

MR. TAYLOR: The application of Pelto Oil Company for a waterflood project, Chaves County, New Mexico.

MR. STOGNER: I assume you want to appear in that case also?

MR. BRUCE: I will appear in

that case, also.

MR. STOGNER: Are there any other appearances in either one of these cases?

There being none, please continue, Mr. Bruce.

How many witnesses will you have, Mr. Bruce?

MR. BRUCE: Two witnesses.

MR. STOGNER: Will the witnesses please stand and be sworn at this time?

(Witnesses sworn.)

MR. STOGNER: Okay, Mr. Bruce, please continue.

MR. BRUCE: Okay.

GERALD B. BURRELL,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. BRUCE:

Q Mr. Murrell, would you please state your full name and city of residence?

A My name is Gerald P. Murrell and I reside in Houston, Teas.

Q And what is your occupation and who are you employed by?

A I'm employed as Vice President of Land with Pelto Oil Co.

Q Would you please briefly state your educational and employment background?

A I'm a 1964 graduate of the University of Texas at Austin with a degree in petroleum land management.

In the intervening 23 years I worked as a landman for Tenneco Oil, Getty Oil, and as a Land Manager, Vice President of Land with several independent companies, the last 7-1/2 with Pelto.

Q And were you in charge of the land matters involved in Case Numbers 9210 and 9211?

A I was.

MR. BRUCE: Mr. Examiner, are the witness' credentials acceptable?

MR. STOGNER: They are.

Q Mr. Murrell, will you please briefly state what Pelto Oil Company seeks by its applications in Case Numbers 9210 and 9211?

A In Case Number 9210 Pelto has applied for statutory unitization of a portion of the Twin Lakes San Andres Associated Pool underlying 4,863.82 acres of state and fee lands in all or portions of Sections 25, 26, 35, and 36, Township 8 South, Range 28 East; Sections 31 and 32 of Township 8 South, Range 29 East; and Sections 1, 2, and 12 of Township 9 South, Range 28 East; Sections 5, 6, 7 and 8 and 18 of Township 9 South, Range 29 East. An exact land description is submitted as Exhibit Number One.

Pelto seeks to unitize this area for the purpose of establishing a secondary recovery waterflood project, which is the subject of Case Number 9211.

Q Would you please refer to Exhibit Number Two and describe its contents for the examiner?

A Yes. Exhibit Two is a plat which outlines the unit area and identifies the separate tracts within the unit area. These tracts are formed on the basis of according to common mineral ownership and there are 37 separate tracts within the unit area.

Pelto is the operator of all tracts except Tract Number 17, which is operated by the Harlow Cororation.

MR. STOGNER: I'm sorry, who?

A Harlow Corporation.

Q Would you please describe the unitizes formation?

A The unitized formation is the San Andres formation underlying the unit area with vertical limits found in the interval between 2708 and 2798 feet, as recorded on the duolateral log in the Pelto Oil O'Brien L No. 16 Well on December 23rd, 1984. This is the same as the Twin Lakes San Andres Unit Well No. 80. This well is located 2310 feet from the north line and 1675 feet from the east line of Section 6, Township 9 South, Range 29 East, in Chaves County.

The unitized formation will include all subsurface points throughout the unit area correlative to this depth.

Q Would you describe how Pelto Oil Company came to be an operator in this field and how it decided to seek unitization of the field?

A Yes. In 1984 Pelto Oil investigated this area among others as a potential secondary recovery project and determined that the Twin Lakes San Andres Pool could be successfully waterflooded.

In 1984 we purchased the entire operating interest of Stevens Operating Corporation and instituted further engineering studies to determine waterflood feasibility. We have subsequently purchased additional interest, working interest in the area and at this time Pelto owns record title to approximately 72 percent of the working interest in the unit.

We undertook to further this as a result of our already -- we had already conducted engineering studies in support of the purchase of the Stevens interest, and since the Stevens interest constituted 85 to 90 percent of the unit area on the surface acre basis, we decided, elected to move ahead with the waterflood project.

Q Would you plese refer to Exhibit Number Three and describe it briefly for the Examiner?

A Exhibit Three is a copy of the unit agreement for the proposed Twin Lake San Andres Unit. This unit agreement was drafted based upon other similar agreements which had previously been approved by the State Land Office and the Oil Conservation Division.

The unit agreement describes the unit area and unitized formation. The unitized substances include all oil and gas produced from the unitized formation; however, even though small amounts of gas may be recovered, the secondary recovery project is aimed only at recovering additional oil.

Designated unit operator is Pelto Oil Company and the unit agreement provides a method for removal of unit operator.

The agreement also provides for expansion of the unit area; however, at this time Pelto does not foresee any expansion of the unit.

Q Would you please refer to Exhibit Number Four and describe its contents?

A Yes. Exhibit Four is a copy of the unit operating agreement for the proposed unit area. This document sets forth the authorities and duties of the unit operator as well as the apportionment of expenses by and between the working interest owners.

Q Okay. Would you please describe tract ownership and how you determined the names of the working interest and royalty interest owners within the unit area?

A Yes. Exhibit Five is a tract by tract listing of the interest owners. These names were obtained from Pelto's current Division Order and/or title opinion files, since it operates all but one of the tracts.

Tract 17 ownership was initially determined by conducting a check of county records, but that check was found to be incorrect and subsequent ownership was determined from current Division orders which were provided by the Tract 17 working interest owners.

Q How many royalty and working interest owners are there in the proposed unit?

A There are 61 royalty owners and initially there were 17 working interest owners there; we're down to 11 now. There have been some repurchasing, some acquisitions of interest within the unit.

Q Would you please describe your attempts to obtain the voluntary commitment of working interest and royalty interest owners in the unit?

A Yes. Initial contacts were made with some of the major working interest owners in 198 -- late 1986 by telephone and/or meetings, including Tenneco and Petrus, which is now Pelto, Petrus, P-E-T-R-U-S, which is now owned by Pelto, Sun Oil, W. G. Stroecker, and Marion Weeks.

The first general meeting was called for June 24th 1987, when finalized agreements and an engineering report were sent out by letter on June 9th of 1987; however, by telphone follow-up many of the working interest owners were unable or unwilling to attend for a variety of reasons. Only Harbert Energy representative were in attendance.

By follow-up certified mail dated June 29th, 1987, we advised all working interest owners of the June 24th meeting results and once again requested questions, comments, and/or ratification in order that we could set a new meeting date.

We received minimal response and in fact were advised by Sun that its interest was so small it would not join the unit but would entertain offers to purchase.

Tenneco likewise advised that its interest was to be included in a package with other properties to be sold and telephone follow-up to the June 29th letter revealed that the interest of NRM Operating, Edwards and Leach Oil Company, Adams & McGahey, John W. Adams, and the Estates of R. W. and June Adams, had been or were in the process of being purchased by the Harlow Corporation.

The June 29th letter resulted in ratifications by Harbert Energy, Nabob Production Company, W. G. Stroecker, and Marion Weeks.

Since a number of the working interest owners had expressed an intent or desire to sell, Pelto then made written offers to purchase the interest of all remaining working interest owners. As a result we have reached agreement to purchase in principal with two owners and are negotiating on several others.

Columbia Gas notified us last week that it intends to join the unit.

We have had no response to our letters or telephone calls from TXO Production other than a call following up our offer to purchase, requesting a list of the inventory of well equipment. That was furnished to them but we have not since heard from them.

The Winther interests, we've not received their ratification but in a telephone conversation yesterday with Mr. Winther he advised that those had been placed in the mail from Fairbanks, Alaska, within the past two weeks.

It's Pelto's intent to offer any working and royalty interest acquired to the working interest owners in the unit who have voluntarily joined the unit at the time of such acquisition.

Initial royalty owner contact was made by letter dated December 22nd, 1986. Copies of all pertinent agreements and documents were mailed certified to the royalty owners on July 9th, 1987, and this mailing resulted in commitments of slightly over 73 percent of the unit royalty owners.

A subsequent mailing on August 11th, 1987, accounted for another 3+ percent and telephone contacts were then made or attempted on the remaining unsigned major royalty owners.

Q In your opinion have you made a good faith effort to secure the voluntary unitization of the parties in the pool being unitized?

A Yes.

Q Referring back to Exhibit Five and also moving on to Exhibit Number Six, would you please discuss what percentage of the working interst ownership has committed to the unit at this time?

A Yes. Exhibit Six is a summary of the status of working interest owner commitments as of 9-4-87. Excluding the interest of Winther but including the commitments of Sun and Columbia, we now have commitments to approximately 87-1/2 percent of working interest ownership in the unit.

Q And referring to Exhibit Numbers Five and Seven, what percentage of the royalty interest ownership has committed to the unit?

A Exhibit Seven is a summary of the status of royalty owner commitment as of 9-4-87, and although not reflected in Exhibits Five or Seven, we received ratification yesterday by Mr. Frates Seeligson, F-R-A-T-E-S S-E-E-L-I-G-S-O-N, which means that we now have 83.6 percent of the royalty interest owners voluntarily committed to the unit.

Copies of ratifications executed by working and royalty interest owners are submitted as Exhibit Number Eight.

In addition, the Commissioner of Public Lands, which has 9.8 percent of the total unit royalty, has preliminarily committed the State's royalty interest as shown in Exhibit Number Nine, contingent upon OCD approval.

Q And that would bring you up to over 90 --

A That would bring the total up to over 93 percent.

Q Regarding nonconsenting working interest owners, does Pelto Oil Company request that the order issued in Case 9210 provide for carrying working interst owners?

A Yes. Pelto requests that any working interest owner who does not pay his share of initial unit (unclear) cost be carried with his share of costs being payable out of production, together with a 200 percent charge assessed as nonconsent penalty. We think this is reasonable based on the high capital cost for unit and waterflood.

Q With respect to the proposed waterflood, would you please describe any unique problems and expenses attributable thereto?

A Yes. There's an insufficient -- there's insufficient water in quantity and in quality in the immediate area of the proposed unit within which to institute a waterflood project. Realizing the critical nature of this scarcity, Pelto acquired water rights in Lea County, approximately 27 miles southeast of the unit. In addition, Pelto acquired rights-of-way on which to build a pipeline from the water source to the field. A plat showing the location of the water source and the right-of-way to the field is submitted as Exhibit Number Ten.

The cost of acquiring the water rights and the rights-of-way was approximately $239,000.

While this will be discussed by our next witness, Pelto Oil Company requests approval of this expenditure as a unit expense. The water source, rights-of-way and pipeline will be owned by the unit's working interest owners in proportion to their unit participation.

Q Was notice of Case Numbers 9210 and 9211 given by certified mail to all interest owners in the proposed unit area?

A Yes, it was. A notice consisting of a cover letter with copies of the applications in Cases Number 9210 and 9211 attached was sent by certified mail to all interest owners. Copies of the letter and copies of the certified return receipts are submitted as Exhibit Number Eleven.

We have not yet received several of these certified return receipts but will submit them to the OCD when we receive them.

Q In your opinion will the granting of the unitization and waterflood applications be in the interest of conservation, the prevention of waste, and the protection of correlative rights?

A Yes.

Q Were Exhibits One through Eleven prepared by you or under your direction or compiled from company records?

A They were.

MR. BRUCE: At this time, Mr.

Examiner, I move the admission of Exhibits One through Eleven.

MR. STOGNER: Exhibits One through Eleven will be admitted into evidence at this time.

MR. BRUCE: I have no further questions of the witness at this time.

CROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Murrell, is it Murrell?

A Murrell, uh-huh.

Q Mr. Murrell, as far as your certified mailing, when was this done?

A Which -- which particular mailing do you mean?

Q The one notifying of today's hearing.

A That was on August the 20th, I believe, or August 19th, August 19th.

Q Now this is Exhibit Number Eleven, right?

A Right.

Q Okay, it's dated August 20th, right?

A Is it dated August 20th? Oh, yours went out the 19th, mine went out the 20th, yes, I'm sorry.

Q Okay, now when you say his, which document are you referring to?

A That's one that hasn't been admitted yet.

Q Oh, okay, it will be admitted later. Okay.

Run this by me again. As far as the uncommitted royalty interest owners, when were they first notified?

A On July the 9th.

Q Of this year?

A Of this year. Well, now, actually they were first notified by letter on December 22nd of 1986.

Q Do you have that particular document or what essentially was it or is that in a packet somewhere?

A It was jsut -- no, we did not send a package to them at that time. It was a letter notifying them of the status, that we were preparing to send them documentation on the unit. We had had a number of inquiries about the nature of the royalty and what was happening, and we felt it was best at that time to respond to the working interest owners as a whole, advising them where we were headed with the waterflood.

The actual documents, the unit agreement and ratifications, were sent on July 9th of this year.

Q And how about your working interest owners?

A Working interest owners, as I say, we had some -- some preliminary early meetings with them during 1986; however, the official letter with all the documentation went to them on June the 9th, 1987.

Q Have you received any objections from any of these parties?

A No, we've had no comments with respect to objections to the operating agreement or the unit agreement.

We've had, as I said, a number of people who have just expressed an interest in selling their interest and, of course, we had the expression from Sun that they weren't going to join the unit.

Q And as far as your royalty interest list of the uncommitted royalty interest owners, have any of those expressed an opposition to your unit agreement?

A Definitely not. We've had an overwhelming response from the royalty owners.

Q Okay. Those that have not responded, have you found that most of them can't be found or what is --

A We can't find some of them. We've got addresses; however, some of the certified receipts we've gotten back or have not gotten back are for royalty owners which we've tried to run down and in some cases haven't been able to do that.

Q Okay. In your testimony you mentioned a

200 percent penalty to carry some of the uncommitted. Are you talking about the uncommitted working interest owners?

A Just the working interest owners, correct.

Q Mr. Murrell, are you aware of any amendment to the Statutory Unitization Act allowing for such a penalty in New Mexico statutes?

MR. BRUCE: It's a --

MR. STOGNER: You ought to be able to just point me to it.

MR. BRUCE: 70-7-7(s).

Q Are there any Federal acreage involved in this unit?

A No, sir.

Q What percentage of it is state lands?

A State land is here somewhere.

Q Exhibit Number Seven?

A Exhibit Number Seven, I believe, yes, uh-huh.

Q This is a preliminary approval?

A Yeah, that's percentage of the royalty interest. I had the -- here it is. It's on Exhibit Number Five, I believe, at the end. Nope, sorry.
believe, at the end. Nope, sorry.

Yeah, 640 acres is State; 4,223.82 acres is fee; or approximately 13.16 percent State; and 86.84 percent fee.

Q Another difficult question. Where is that State acreage at?

A Section 36 of Township 8 South, Range 28 East. It will be Tracts 1 through 11.

MR. STOGNER: I have no further questions of this witness.

Mr. Bruce, do you have any further questions?

MR. BRUCE: Nothing further, Mr. Examiner.

MR. STOGNER: At this time we'll take a 10 minute break.

(Thereupon a recess was taken.)

MR. STOGNER: This hearing will come to order.

Mr. Bruce.

MR. BRUCE: Just to be safe, Mr. Examiner, I move the admission of Exhibits One through Eleven.

MR. STOGNER: Exhibits One through Eleven will be admitted into evidence.

ROBERT L. SPOTTSWOOD,

being called as witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. BRUCE:

Q Mr. Spottswood, would you please state your full name and your city of residence?

A My name is Robert L. Spottswood and I live in Houston, Texas.

Q And what is your occupation who is your employer?

A I'm the Manager of Petroleum Engineering for Pelto Oil Company.

Q And would you please state your educational and work experience?

A I received a BS in petroleum engineering from the University of Oklahoma in January, 1953; couple of years in the United States Army Engineers; and I have 27 years with Shell Oil Company in various petroleum reservoir engineering assignments in the United States and Holland, including numerous waterfloods as Project Engineer and Project Manager; then two years with Enstar Petroleum as Corporate Manager of Petroleum Engineering; and 3 years with my current employer, Pelto Oil Company, as the Manager of Petroleum Engineering.

As part of my job I've been in charge of the engineering matters related to the proposed Twin Lakes Field unitization and waterflood.

I'm a Registered Professional Engineer in the State of Texas, and I have appeared before the New Mexico Oil Conservation Commission in 1964 as a witness.

MR. BRUCE: Mr. Examiner, are the witness' credentials acceptable?

MR. STOGNER: They are.

Q Mr. Spottswood, after purchasing its working interest from Stevens Operating Corporation, did Pelto Oil Company begin preparation of a waterflood and unitization feasibility study and please I refer you to Exhibit Number Twelve?

A Yes. We -- we started a waterflood unitization feasibility study and it resulted in what's seen as Exhibit Twelve.

This study was prepared by Pelto Oil Company personnel with assistance, technical assistance, from consultants outside the company. It's taken about two and a half years of study.

As already testified, we anticipated Pelto Oil Company to have greater than 70 percent of the working interest and most of any one of the other working interest owners were very small. They lived anywhere from Birmingham, Alabama, to Alaska; therefore, we went ahead on a Pelto study without a technical committee, as such, but we had technical sessions with working interest representatives from Tenneco and Petrus, Harbert Energy Corporation, and we've had technical discussion, comments on the telephone, with Harlow Corporation, Columbia Gas, and Mr. Stroeker in Alaska.

Q Would you please discuss the history of the Twin Lakes Field, and I refer you to Exhibit Thirteen, I believe.

A I might say that some of the exhibits, Mr. Examiner, are in the engineering study and others have been added to it.

This is -- Exhibit Number Thirteen is the production history curves from the Twin Lakes Field from December, 1964, through April of 1986.

The Twin Lakes Field was discovered in November, 1964, with O'Brien C. No. 2 in Section 1, Township 9 South, 28 East, in Chaves County, New Mexico. It flowed 20 barrels of oil a day, 21 degree API sour crude, from the Permian San Andres formation.

Development on 40 acres began in 1967, you'll notice the producing well count up at the top, and it reached 15 producers by the end of 1977.

Rapid development occurred between 1978 and 1982 and then in November of 1981 the oil production reached a peak at 86,000 barrels of oil per month, 60,000 MCF per month of gas, and 21,000 barrels of water per month from 106 producers.

And then from that point on you can see that the decline in oil production has set in. It's due mainly to the depletion drive mechanism that's in this reservoir with a very slight gascap expansion and some limited interstitial water production. For example, the average gas/oil ratio in 1979 was about 652 cubic feet a barrel versus the 300 cubic feet a barrel of the solution ratio estimate. This has been progressively increasing to 2037 cubic feet a barrel in 1986 and is currently around 2150.

The reservoir pressures we've seen from an initial 915 psia in many parts of the field have dropped down below 100 psia.

The cumulative oil production to April the 1st, 1986, was about 4-million barrels of oil and 4.1 BCF of gas, 2-million barrels of water, with an estimated plus or minus 1-million barrels of remaining movable primary reserves.

Field production during March of 1986 was down to 16,262 barrels of oil, 29.6-million cubic feet of gas, and 25,167 barrels of water from 115 producers.

Cumulative production to date through May of 1987 has been 4.1-million barrels of oil, 4.4 BCF of gas, and 2.3-millio barrels of water and the current May, 1987, field production was 9,705 barrels of oil, 122,215 MMCF of gas, and 21,716 barrels of water from 97 producers.

1983 Pelto Oil Company looking for producing properties to buy, which had development potential, made a field performance study which indicated low primary oil recovery efficiency and potential additional oil recovery through waterflooding.

We then acquired Stevens Oil Company interest in the field in May, 1984, and we started our detailed engineering waterflood feasibility study from which we've concluded.

I'd like now to move to Exhibit Number Fourteen, which is the main portion of the field, and I'll come back later to describe which part of the field is the main portion of the field. The proposed unit area in this particular exhibit of production covers, or it has produced about 98 percent of the field oil cumulative to April the 1st of 1986.

The -- some of the conclusions, again this is a similar type of exhibit showing the production from December of '64 to April the 1st, 1986, some of the conclusions from our engineering study are as follows:

One, the Twin Lakes San Andres formation can be successfully waterflooded.

Number two, the cumulative oil production to April the 1st, 1986, was 3,819,000 barrels, or 7.4 percent of the oil in place. Cumulative gas production to April the 1st, 1986, was 4 BCF of gas, and cumulative water production to April the 1st, 1986, was approximately 1.7-million barrels of water, which represents 31 percent water in the total fluids.

Point number three, movable primary oil reserves at April the 1st, 1986, down to an economic cufoff of one barrel per day per well, was about a million barrels of oil, or 1.9 percent of the oil in place. The economics and methods of operation will dictate the amount of recoverable primary oil, and I'll discuss this later.

Point number four, additional secondary oil reserves in the range of 4.8-million barrels, with a secondary primary ratio of one, down to about 2.893-million barrels with a secondary primary ratio of 0.6, could be anticipated from waterflooding, which brings the total proposed unit recovery efficiencies, primary plus secondary, up to 14.9 percent on the low side up to 18.6 of the original oil in place as a potential high side.

Point number five, since April the 1st,

1986, the proposed unit has been operated at an overall loss. Leases are being maintained for inclusion into a waterflood unit and in the last three months of 1987 the field in the proposed unit area is back to a marginal profit position.

Point six, conclusion six, an adequate, dependable and compatible source of water is required in order to profitably waterflood the Twin Lakes Field and Pelto has acquired this along with rights-of-way from the -- from an Ogallala source 27 miles southeast of the Twin Lakes Field.

Conclusion seven, total cost of the proposed waterflood project is estimated to be $8.3-million and economics based on a constand $15.00 per barrel of oil with unescalated costs, show a reasonable profit.

Point number eight, unitization is the most efficient and economical method of enhancing remaining primary reserves and recovering secondary reserves in the Twin Lake Field.

Conclusion nine, a single cost revenue factor for unit participation should be based upon ultimate primary oil recoveries for both working and royalty interest.

And then the final conclusion ten, due to the advanced stage of primary depletion and marginal economics of continued nonunitized primary operations, we respectfully request the expeditious granting of our waterflooding and unitization applications.

Q Mr. Spottswood, would you refer to Exhibits Fifteen and Sixteen and discuss the interval which Pelto Oil Company proposes to waterflood?

A Okay. Mr. Examiner, Exhibit Fifteen is just a print of the log that we're also submitting into evidence as Exhibit Sixteen, so it's a lot easier to look at Exhibit Number Fifteen, but the log has been marked, also.

In looking at Exhibit Fifteen in the proposed unitized interval on the duolateral log curve to the left, oil is produced from two major zones in the field, designated as P-1 and P-2 in the San Andres formation. Well production performance, infill well data, and workover experience support both the P-1 and P-2 zones are contributing to production.

There is another zone, as you can see, called the San Andres P-3, and it is not productive in the field.

We have subdivided the P-1/P-2 interval into five sub-zones, which reflect fluctuations in sea level, and in examination of core samples and limited ditch cuttings indicate rock types are in this field that have been encountered in the tidal flat environment. These fine-grained reservoir rocks of lower permeability consist of porous dolomite, anhydritic dolomite, and dolomitic anhydrites.

Q Could you please discuss the geology of the Twin Lakes San Andres area and I refer you to Exhibit Seventeen?

A This Exhibit Number Seventeen is a structure map on the top of the P-1 zone.

One thing that I might point out, that the contours here are above -- feet above sea level. As you can see, the structural strike is essentially north to south with an eastward dip at 60 to 200 feet per mile.

The east flank is relatively steep with origins of steepening we're really not certain from where it came.

The down dip limits of the field have not been clearly established since a free water level has not yet been encountered and I'll discuss the producability of the down dip wells later.

There's been a minor structural closure on the west side of 25 to 30 feet, where production data indicates a small initial gas cap, probably less than 5 percent of the hydrocarbon filled pore space within the unit is found.

Q Are these zones, the P-1 and P-2 zones, continuous across the proposed unit area, and I refer you to Exhibits Eighteen and Nineteen.

A Right. Yes, they -- these sub-zones are continuous across the -- across the proposed unit area.

Cross section A-A' is a dip cross section from east to west. It shows the sub-zone continuities and I might add that there have been four infill wells drilled in the field and they have shown drainage which indicates continuity between zones.

Exhibit Number Nineteen also shows sub-zone continuities and it's a strike cross section from north to the south.

Q Would you also please discuss Exhibit Number Twenty?

A Exhibit Number Twenty is a regional schematic north/northwest to south/southeast cross section, where the line of section is at right angle to the facies strike. The facies strike in the northeast to southwest direction is inferred in order to explain the oil trapping mechanism, so you can look up to the northwest there, of the field, seals are formed by dense anhydritic dolomite and anhydrites. To the southeast these rocks grade into very fine-grained secrosic (sic) dolomites of increasing reservoir qualities. This overall trend is systematic and predictable on a regional scale; however, local nonsystematic variations on the field development scale are to be anticipated and we have encountered these in the Twin Lakes Field, and that is some down dip decrease in permeability.

Q Would you please refer to Exhibit Twenty-one and discuss the log coverage of the wells in the field?

A Exhibit Twenty-one is a plat which shows log and core coverage. 126, or 75 percent of the 169 wells drilled in the field have a resistivity and a porosity log. 28 other wells have only cased hole porosity logs available. 15 wells have no log data or only an uncalibrated cased hole neutron log. Most of hte 43 wells with poor log coverage are located on the west side of the field, and you can see that in -- in the triangles and also the rectangles.

There are scattered places throughout the rest of the field where only cased hole log data are available. I might add at this point, this is the main reason for excluding oil in place as a unitized parameter because of the poor log coverage.

As can be seen, six wells were cored with varying amounts of data available on five wells and we ran special analysis on cores from two wells, the Citco State 7 and the O'Brien L-16. Waterflood susceptibility tests indicate that significant amounts of oil can be removed from these rocks by water injection.

I might add that in our engineering report, pages 4 through 6, the net pay criteria is fully discussed.

Q Does the proposed unit area include the entire Twin Lakes Pool?

A The proposed unit area does not include the entire Twin Lakes Pool.

Q Would you please refer to Exhibit Number Twenty-two and discuss the reasons for that?

A Exhibit Number Twenty-two shows the distribution by well of the 4-million barrels of cumulative oil produced to 4-1-86, and you'll notice the circles and the numbers beside represent the cumulative amount of oil that's been produced.

As you can see, there's a wide variation in oil cumulatives, which reflect time of drilling, reservoir quality, influence of the gas cap. Note the poor oil recoveries around the periphery and in the northern portion of the field. The unit outline was selected to encompass what we believe is the economically floodable portion of the field. We drew around 40 -- the unit was drawn around 40-acre locations with a producer, around recommended and probable undrilled locations, and around some open, undrilled spots to protect the unit. Look up to the northern boundary there. It follows a break in well performance in Sections

25 and 30. The last row of good oil producers are included in the unit. The next row of wells to the north have much lower oil cumulatives. For example, about 4700 barrels per well on the first row right outside the unit to the north versus 28,600 barrels per -- of oil per well on the first row to the north in the unit.

We think that the poor recovery reflects lower rock permeabilities; that is, a lower pay quality. For example, the recoveries translated in the wells to the nroth of the unit, first line to the north, recovered about 6 to 8 stock tank barrels per net acre foot, and the last row of wells in the unit recovered about 37 stock tank barrels per net acre foot.

The overall average primary oil recovery in the north, in the area north of the unit is estimated to be 162 barrels per acre versus 991 barrels per acre within the proposed unit, or these wells have averaged about 6000 barrels per well recovered versus 33,000 barrels per well recovered in the main area and the recovery efficiency in the north has been about 1.8 percent of the oil in place versus about 9.3 percent of the oil in place in the south.

The recovery of oil in the north represents only 4 percent of the field ultimate primary recovery.

Also you'll notice -- or another point is that the producing water cuts from the north area have been very high. They've averaged 55 percent water initially and 67 percent water cut cumulative to April the 1st, 1986, versus the main portion of the field cumulative average water cut to date, through April of '86, was 31 percent water cut.

Another point on the -- that helped -- that we looked at to decide about including the north area or excluding it, you'll note that the drill locations in the north make it difficult to install an efficient waterflood pattern without excessive drilling. The estimated capital cost per additional barrel recovered in the north is about five times that that we expect in the south.

All of these facts led us to the conclusion that there is too high of a risk associated with waterflooding the north area of the Twin Lakes Field.

Q Would you please move on to Exhibit Twenty-three and discuss the permeability?

A Exhibit Twenty-three is a net pay Isopach map of the proposed unit area. As previously stated, well production performance, infill well data, and workover experience support that both P-1 and P-2 zones pay plus probable categories are contributing to oil production. Since our analysis of the north end indicated that waterflooding would be highly risky and uneconomic, we did not include a net pay Isopach on this map.

Note on -- in the main kpart of the field a lack of pay data in the northwest portion of the main field area, which we've already discussed the lack of log data on Exhibit Number Twenty-one. As can be seen, there are wide variations between a well's ultimate oil recovery and net pay as defined by logs. This isn't surprising since these kinds of rocks can have wide ranges of permeability for a particular porosity as indicated on the log. This is particularly true in the north end, also.

The edge areas of porosity pinchouts and low rock permeabilities are mainly defined by poor well performance as previously discussed under cumulative oil production, Exhibit Number Twenty-two.

We -- we made an original oil in place calculation and came up with about 51.5-million barrels in place and the techniques to do this is described in our feasibility study on page six for determining pay, porosity, water saturation, in calibrated cased hole logs and assuming values for wells without logs and in uncalibrated cased holes.

Under these assumptions oil in place determinations are not accurate enough for tract unitization parameter considerations.

Q Would you please refer now to Exhibit Twenty-four and discuss how primary reserves in the unit were calculated?

A Exhibit Twenty-four illustrates how each tract's remaining primary oil reserves were consistently extrapolated. As you can see, this is a combination of hyperbolic and exponential declines.

The hyperbolic best fits the early decline, then an exponential decline of 11 percent per year, which was exhibited by the older wells in the Twin Lakes Field, was used for the remainder of tracts producing life. A history cutoff date of April the 1st, 1986, was used in order to reflect the somewhat stable economics prior to rapid drop in and gas prices in April, 1986.

For example, in 1985 the field oil price varied between $24.50 and $25.00 per barrel.

In January, 1986, it dropped to $25.38; February, $23.13 a barrel; March, $15.91 a barrel; and in April it further dropped to $11.98 a barrel; and this dropped right on down to a low point in August of 1986 of $8.88 per barrel. In other words, oil prices dropped a maximum of $16.50 in 1986 and some 26 producers were shutin to reduce operating losses. It went from 95 producers in 1985 on down to a low of about 69 in December of 1986.

A tract cutoff limit of one barrel of oil per day per well was assumed as a measure of ultimate movable primary oil which would reflect economics prior to the rapid drop in oil and gas prices in April, 1986.

The actual economic limit is probably closer to 4 barrels per day at a current December, 1986, price, and I'll discuss these two economics limits a little more fully later.

Q In your opinion has the pool been adequately defined by development?

A Yes.

Q And is the pool in an advanced state of depletion insofar as primary production is concerned?

A Yes.

Q As part of the feasibility study were primary and secondary reserves calculated?

A They were.

Q Please refer to Exhibits Twenty-five and Twenty-six and discuss those calculations.

A Exhibit Twenty-five shows the proposed unit area primary oil production history and forecast using one barrel of oil per day per well cutoff. From the sum of individual tract curves remaining primary moveable oil reserves are about a million barrels for a total primary ultimate of 4.8-million barrels, or 9.4 percent of the original oil in place.

Note the exponential decline from 1987 to 2001, where then there's a rapid falloff in the number of producers.

And Exhibit Number Twenty-six shows the proposed unit area primary oil production history and forecast using 4 barrels per day per well cutoff. Also from the sum of individual tract curves, remaining primary oil reserves are only 391,000 barrels, which gives a total primary ultimate of 4.2-million barrels or 8.2 percent of the original oil in place. Note the very rapid falloff in oil production, the number of wells, and then the shorter life compared to one barrel per day per cutoff.

Later we'll present comparative economics of continued primary operations at $15.00 per barrel of oil versus waterflooding, which will show about 300,000 barrels remaining primary reserves under an economic forecast.

However, as we've pointed out, the proposed unit has been operated at an overall loss since April the 1st, 1986, except for the last three months of 1987, in order to preserve leases for inclusion into the waterflood unit.

I'd like to move right on in and discuss the secondary performance now. The ratio of secondary recovery to primary ultimate is an industry-accepted method of estimating waterflood recoveries from comparable reservoirs. We made a review of analog San Andres fields under a waterflood for comparison.

Three San Andres fields, Chaveroo, Flying

M, and Milne Sand, having the same depositional environment, ranges of net pay, porosity and permeability and oil gravity as Twin Lakes, were selected as analogs. The estimation of secondary to primary ratios of these analog fields varied from 0.6 to 1.4 with the low end reflecting inefficient injection patterns and rates.

From this review a range of secondary to primary ultimate recovery ratios of 0.6 to 1.0 appear reasonable for the Twin Lakes Field.

Q With a waterflood project instituted, what does Pelto Oil Company forecast for unit production, and I refer you to Exhibit Twenty-Seven?

A Exhibit Twenty-seven shows the history and three forecasts of the unit oil production. You can see the drop in production there in '87 reflects the conversion of producers to injectors.

We anticipate about one year injection until the reservoir is filled up.

The high recovery case, secondary to primary ratio equal to one, portrays an assumed peak oil production of 48,400 barrels per month or about 1600 barrels of oil a day, to be reached by 1991, assuming water injection began in July, 1987. Now we're experiencing a six or eight month delay in starting injection from these forecasts.

This peak is only 60 percent of the primary peak of 2,672 barrels of oil per day, which was reached in 1981, and is only 8 percent of the anticipted unit water injection rate.

The low recovery curve, secondary to primary 0.6, has a peak of 33,400 barrels per month, or 1100 barrels of oil a day also reached in 1991, and is 41 percent of the primary production peak and 5 percent of the anticipated water injection rate.

These peak oil rates are somewhat higher than those observed in the analog fields of Milne Sand, Chaveroo, and Flying-M, due to our planning and immediate full scale injection rates in primarily closed 5-spot patterns in the Twin Lakes Field. Note we're looking at 20 to 22 year waterflood life.

Now the bottom curve called remaining primary movable oil reflects a 1-barrel per day per well cutoff and the 4-barrel per day per well cutoff not shown; forecast ends in 1994.

Q Would you please refer to Exhibit Twenty-eight and discuss the waterflood pattern for the field?

A Consistent with analog field performances, 80-acre 5-spot patterns were selected to provide maximum sweep efficiencies with designed oil production and injection capacities at minimal cost. This pattern also provides the flexibility for selective 20-acre infilling or converting to normal 9-spots of flood performance, as that might dictate.

You'll note the northeast to southwest injection pattern parallel what we think are natural formation fracture trends which might exist. You'll see four infill wells there with the large circles that have already been drilled and we believe that they will give us additional data on directional response if any is noted.

Poor producers, eccentric drilling patterns, and a need to inject into the original gas cap on the west, prevent oil migration, results in irregular patterns on the west and the southwest sides.

You'll notice also we've labeled with stars there three injectors are proposed to be drilled to complete four important 5-spots on the northeastern and eastern edge of the proposed unit.

We also show four edge wells are shown as shut-in producers for future utility or alternate producers or injectors as the need arises.

Up to the north just outside of the unit there are two wells that we show as potential injectors and we are currently negotiating for these two wells with offset operators.

Q Does Pelto Oil Company request that the order in this matter contain and administrative procedure for approving unorthodox well locations and for changing producing wells to injection wells?

A Yes. As a waterflood program continues it may be necessary to convert producing wells to injection wells or to drill additional injection or producing wells and we request that an administrative procedure be established in the order by which a well can be converted to an injection well or a producer or an injector could be drilled by applying to the OCD for administrative approval, providing that OCD rules are complied with.

Also it may be necessary to drill additional injection or producing wells at unorthodox locations and Pelto Oil Company requests that such unorthodox locations be approved administratively.

Proposed special pool rules for these requests are submitted as Exhibit Number Twenty-nine.

Q Please look now at Exhibit Thirty and discuss the production system for the unit.

A Exhibit Number Thirty shows a production system which will all be new. It has been designed by West Texas Consultants under Pelto's direction. You'll see there's a central facility which will have free water knockout, heater-treating, fiberglass oil storage tanks, skim tank, and a lease automatic (not understood) transfer.

There'll be main gathering lines for oil plus water and a low pressure fiberglass -- which are low pressure fiberglass, and a separate gas gathering line. There are five satellites for the 58 producers which each producer will have a 3-inch polyethylene flow line on the surface and at each satellite we'll have individual -- ability to make individual well tests for oil, gas, and water, and then we will allocate monthly production back to each well.

The electrical distribution system will be completely rebuilt in the field.

Q Please now move on to Exhibit Number Thirty-one and discuss the proposed injection system?

A This injection system was designed by West Texas Consultants under Pelto's direction. The water supply line is coming in there from the southeast. It's from the Ogallala formation wells 27 miles to the southeast. We will also have the ability to inject produced water and we will keep the produced water and the Ogallala water separate at the surface.

I might say that currently the produced water is being disposed of into the White Lake Ranch Dry Bed Water Disposal System.

Also there are central facilities which will include a storage tank, four vertical turbine pumps that have the ability to deliver up to 22,000 barrels of water a day.

Initially we -- we're -- we plan to limit the surface pressure to 540 psig, which is .2 psi per foot and then we have the equipment to be able to go up to a maximum of 1200 psig after step rate tests are approved by the State.

There are five satellites and one central injection point. We'll record volumes and pressures measured on each well. We'll have 1-1/2 inch buried fiberglass injection lines with 1500 pound capacity to each injector and as you can see, or as we've said, we will be converting 55 injectors to producers -- 55 producers converted to injectors and we plan to drill 3 injectors, for a total of 58 injection wells. Again the two wells up to the north are not shown. They would be tied in in the sytem if we're able to negotiated with the offset operators like we think we will be.

The injector will have a stainless steel wellhead. We'll have 2-3/8ths inch fiberglass lined tubing and I'll get into this plus the packer in a couple of schematics of injection wells. We'll set the packers within 75 feet of the top perfs. We will put inhibited, treated water in the annulus and that then is our proposed injection system.

Q What are the capital requirements for

unitization, and installation of the water -- of the waterflood project?

A I'd like to refer you to Exhibit Number 32 and just point out a few things in it.

The total cost of the proposed waterflood project is estimated to be $8.3-million, which consists of $1.1-milion pre-unitization expense; $6.2-million initial installation capital, and $1-million future capital to install larger pumping units during the anticipated peak well responses.

The pre-unitization expenses you can see on this is the summation of the cost incurred and prepared for by Pelto prior to unitization for activities uniquely required to evaluate the floodability of the San Andres reservoir; to acquire water rights and the rights-of-way for water source pipeline; to design the waterflood and facilities, and to determine the cost to install the waterflood.

As you will see under the consultant and legal fees, source water acquisition of $80,000; acquiring the water rights and surface leases, $21,000, and then on down, $4000 for surveying for facilities and water source system.

And then under point number 2, the acquisition of source water some $134,000, already mentioned by Mr. Murrell that we've spent $239,000 on the water source system.

The bottom of this first page of this exhibit shows the subtotal of pre-unitization expense of $1,100,000.

The next page of Exhibit Thirty-two shows a breakdown of the costs were $3.5-million for the waterflood installation facilities, $1.5-million for the water supply system, $900,000 to convert 55 wells to injection, $300,000 to drill 3 injectors, for a grand total of initial capital of $7,300,000, and then when you add the $1,000,000 for anticipated future enlarged pumping units, brings the grand total proposed waterflood costs to $8,300,000.

Q Referring to Exhibit Number Thirty-three and based upon the expenditures you just mentioned, would you please discuss the economics of the waterflood and the anticipated profit for the project?

A Exhibit Number Thirty-three which shows unescalated $15.00 per barrel and $1.50 per MCF economics, which is also shown in the feasibility studies. This -- these analyses exclude Federal income tax and administrative overheads.

The continued primary operation column that you see there shows an operating profit to 4 barrels of oil per day per well; however, during the last months, as we've mentioned, of 1986 and the first part of 1987, the overall unit area was operated at a loss in order to preserve leaseholds for inclusion in the unit. With the oil price dropping from $25.00 per barrel late in '85 to $12.00 per barrel in April and then on down to a low of $8.88 in August, the -- we believe that a $15.00 per barrel represents a reasonable economic forecast.

So the investment of $8,300,000, we see a gain over continued primary and you just subtract those three columns up there of 4,415,000 barrels in the secondary/primary of one increased over primary or under secondary/primary of .6, 3,486,000 barrels gain over primary.

The gas also gained some 1.280 BCF under secondary/primary of one to 1.174 gain in BCF over primary under assumed secondary/primary ratio of .6.

The undiscounted profit over and above primary is some $36.7-million under the secondary/primary case of one and $17.7-million under the secondary/primary case of 0.6.

If you discount the profit at 10 percent, the discounted profit is about 12.2-million over primary under the high case and $3.6-million under the secondary/primary of .6.

Q In your opinion will waterflood operations in this portion of the pool prevent waste and will it result with reasonable probability in the increased recovery of substantially more oil from the pool than would otherwise be recovered?

A Yes.

Q And will the estimated additional costs of conducting unitized waterflood operations exceed the estimated value of additional oil to be recovered plus a reasonable profit?

A No.

Q On what basis are the unitization parameters calculated, and I refer you to Exhibits Thirty-five and Thirty-six?

A Let's see, is it Thirty-five or is it Thirty-four?

Q Thirty-four and Thirty-five.

A Yeah, Thirty-four. Okay, let's look at Exhibit Thirty-four first.

Exhibit Number Thirty-four is similar to what was -- is in the engineering report except we've split it into -- Tract 10 into Tract 10 and 10-A, and everything is identical.

It shows the 37 individaul tracts in the proposed unit that we've already introduced as Exhibit Number Two.

The working interest, royalty interest, and overriding royalty interest data were gathered from

Division orders or, as already testified to. All the production numbers on this particular exhibit are from New Mexico's Annual Production and/or C-115 reports.

As previously stated, a forecast date of April the 1st, 1986, was assumed in order to minimize efforts of the early 1986 rapid drop in oil and gas prices on current production, revenue, and estimated future reserves. Net pay and oil in place values were not determined by tract due to insufficient open hole log coverage and the lack of consistent correlation between well performance and net pay.

Look at the column called Acres. The use of acres in determining unit participation is not appropriate since the proposed unit is essentially fully developed with only a few undrilled locations.

The next column of oil production from January of '86 to April of '86 and April of '85 to April of '86 and the oil and -- current oil and gas revenue period of January, February, March, 1986, were listed to show current information for possible split formula considerations; however, since April the 1st, 1986, the proposed unit has been operated as an overall loss, as we've said, therefore the remaining primary oil reserves, we believe, have little to no current value except to maintain leases for inclusion into a waterflood unit.

Of course, the current production affects the extrapolation used to determine remaining movable primary oil reserves. These reserves, when added to the cumulative production, give ultimate primary oil recovery for each tract, which is the best measure of anticipated oil recovery under waterflood operation.

The uniform decline extrapolation of oil production to a cutoff of one barrel of oil per day per well better measures the remaining primary oil volumes that will be recovered along with the secondary -- additional secondary oil from waterflooding. This cutoff also reflects economics, with escalations, prior to the rapid drop in oil and gas prices in April, 1986.

The last column over there, the primary recoveries from extrapolation to 4 barrels of oil per day per well was used for economics of remaining primary operations at current low oil and gas prices and it's shown here for comparison only.

The most equitable formula for determining working and royalty interest unit participation is a single cost/revenue factor based upon ultimate movable primary oil recoveries with a one barrel per day per well cutoff and these or this is the basis for participation which have been shown in the unit agreements.

Moving right on to Exhibit Number Thirty-five, this particular table has been changed somewhat from the engineering study because -- in order to reflect Pelto acquiring Petrus and some other minor working interest changes.

The first page of this exhibit shows each working interest owner's unit cost participation fraction for the parameters previously discussed and then pages 2, 3, and 4 show each one of the working interest owners by -- by tracts that they have interest in.

Q Does the participation formula contained in the unitization agreement allocate the produced and saved unitized oil to the separately owned tracts in the unit area in a fair, reasonable and equitable basis?

A Yes.

Q Will unitization and secondary recovery benefit the working interest owners and royalty interest owners within the portion of the pool included in the unit area?

A Yes, the royalty interest owners will recover additional revenues and the working interest owners will recover profits beyond that of continued primary production.

Q Would you please now describe the proposed waterflood application which is Case Number 9211?

A We -- we have -- Mr. Examiner, we have already submitted our C-108 application and I propose just to emphasize some main points of that application, if that's all right.

MR. STOGNER: Please do.

A Exhibit Number Thirty-six is a table along with a map, which shows the old and new designated well numbers.

Q Would you please move on to Exhibit Thirty-seven?

A Right. Exhibit Thirty-seven, which was part of the C-108 application is a table of proposed injection wells. It shows 58 proposed injectors, that is 55 producers to be converted to injectors, plus three newly drilled injectors. All the new well numbers are shown, the well location, the type, the date the well was drilled, its total depth and plugged back total depth data, hole and casing sizes and weights, the casing depths and number of sacks cemented, the tops of cement, the proposed injection intervals, the proposed tubing packer depths, and -- are -- are shown on this Exhibit Thirty-seven.

On Exhibit Thirty-eight I've selected just a couple. We submitted some 58 wellbore sketches as part of the application. I want to just take a couple of them and talk about the.

Exhibit Number Thirty-eight is called a

Proposed Injector at the top, Twin Lakes San Andres Unit No. 9, former lease and well number, O'Brien F No. 3. It's a typical producer to be converted to injector.

Notice on the right side are current conditions and then on the left side proposed conditions after the well has been converted.

You can see at the bottom cement data, where the perforations are, the cement top, casing information.

On the left side you'll notice the top of the P-1 at 2527 and the base of P-2 at 2586. We propose to perforate most of the P-1/P-2, the entire interval, but selectively those zones -- those portions of that interval that we believe contain movable oil. As you'll see on the left side there, we're planning to put 2-3/8ths inch OD fiberglass-lined tubing with a plastic-coated Baker Model AD packer at 2452 and this is some 75 feet above the top perforation.

If you'll turn to Exhibit Number Thirty-nine, it is a typical injector of the three that we're going to drill, and it's not yet surveyed and we've talked about the location flexibility in our application; these depths are estimated. Note that we're going to set 5-1/2 inch casing here and cement with 800 sacks. Again on the left side, we're going to selectively perforate and acid treat the P-

1/P-2 interval and then the packer seat with the tubing some 75 feet above the top perf.

Q And do you request approval of all these proposed injection wells?

A Yes, uh-huh, please, please do that.

Q Would you please discuss all wells and leases within one-half mile of the proposed injection wells and I refer you to Exhibit Number Forty?

A Exhibit Number Forty is a map which shows two miles around the field and a half mile radius of the injectors and of course it was submitted with our C-108 application.

Exhibit Number Forty-one, then, is a list of affset wells. There are some 58 producers and 4 shut-in future utility wells in the unit, showing old and new well numbers, the date drilled, the TD and plugback depth, all the pertinent information that's required, with some remarks.

There are also included on this table some 20 wells within or without the unit to -- some of them are to be plugged, some have been plugged, and we have 12 wellbore skectches which were also submitted with this exhibit as part of our original application.

We have included a couple of other wells that we didn't in our original application and that's the

Sandco No. 2 Well and the Harlow Kuchemann No. 2. Those wells were not really required under offset guidelines, but for completeness we've included it in this table and these are the two wells that we're negotiating with the operators to take over and make injectors and if successful, we want administrative approval to convert these two wells to injection.

We believe that all this information shows that wells have been properly abandoned and we have also three wells that we've been in discussion with the State people in Artesia about properly abandoning, O'Brien F No. 8, O'Brien N No. 4, both wells outside the unit, and O'Brien L-14, currently within the unit and it's temporarily abandoned. It has no utility, it's very tight and never produced any -- any oil.

So in conclusion of these outside the unit wells, we believe that -- that others have been properly plugged and abandoned.

Q Would you please discuss injection rates and other matters regarding the proposed waterflood operations?

A As we have stated in our original application, we expect to start injecting rate at about 11,600 barrels of water a day, building right on up to a maximum of 21,800 barrels of water per day, which I might add is the limits of our water rights, of our fresh water rights, or Ogallala water rights, and then we believe that over the life of the field it will average something like we'll be putting in 18,200 barrels of water a day.

We anticipate injecting some 145-million barrels of water over the plus or minus 22-year of the project life, which averages that 18,200 barrels per day. This was determined by taking 75 percent flood efficiency and putting in three floodable pore volumes of water over the life.

The injection system as we've already mentioned, will be a closed system. The Ogallala and produced waters to be injected will be kept separate on the surface.

On the injection pressure side we will limit ourselves to 540 psig or 0.2 psi per foot limit until we see that we could exceed that by a step rate test and receive approval from the State to go up to a maximum of 1200 psi, which is our equipment limitation.

The water source, as we've said, is Ogallala water and it will be produced water as the waterflood matures.

The Ogallala is the closest acceptable water source that has a sustained -- can sustain volumes in the rates that we need. We have an appropriation of 1030 acre feet per year, which is about 21,892 barrels per day and we have received from the State Engineer rights to appropriate this and the State Land Office has granted us right of easement for this remote water, water source.

We, as stated in our C-108 application, we plan to selectively clean out, perforate, and acidize injectors where needed, and as producers respond, they will also be selectively stimulated as -- as needed.

Q Are there any fresh water sources in this area, and I refer you wot Exhibits Forty-two and Forty-three?

A No, there are no known fresh water aquifers, that is, the total dissolved solids less than 10,000 milligrams per liter, in the immediate vicinity of the Twin Lakes Field.

I'd like to refer you to Exhibit Number Forty-two. This is an analysis to determine the compatibilities of Dakota and Santa Rosa waters with San Andres produced water.

The first page there is the Dakota formation water, located in Section 35 on the west side of the main part of the field. As you'll see, it has a high total solids of 24,970 parts per million, which is certainly not a fresh water aquifer.

I might add here that the Martin Laboratories, who've done a lot of work for us and do a lot of other work in compatibilities, recommend not injecting this water into the San Andres or mixing it on the surface due to calcium sulfate precipitation and scaling problems.

Other formation water analysis in this exhibit from the Santa Rosa formation water in Well No. 1, which is in the east half of Section 35, Well No. 2, which is in Section 26, both of these are on the west side of the field around 900 feet, or so, and you'll see from the Santa Rosa analysis both contain high solids, 12,000 to 22,000 parts per million, which are certainly not fresh water aquifers.

The Martin Lab concludes that the Santa Rosa water could be injected into the San Andres; however, these samples may have had too much iron and solids due to wells not cleaned up.

And then there's a final analysis of the San Andres water, which was from the White Lakes Ranch disposal system, and you'll see there it's very high total solids of 223-to-240,000 parts per million.

Exhibit Forty-three is another water analysis exhibit from three water wells in the Twin Lakes Field from 500-to-630 foot depth. Notice here again the high solids content from 12,500 to about 13,500 parts per million; certainly not fresh water.

The laboratory concludes here there's no incompatibility injecting Santa Rosa waters in the San Andres and I might add that we use Santa Rosa waters in our two injectivity tests but we believe that's somewhat of a limited reservoir and it cannot sustain the volumes and rates that -- tht we need.

Q Would you please discuss the source of the Ogallala injection water and its compatibility with water in the San Andres formation?

A I'd like to refer you to Exhibit Forty-four, which is a Martin Laboratory's water compatibility analysis of the Ogallala and the San Andres.

In July, 1986, we had Martin Laboratories in Monahan, Texas, mix Ogallala water with San Andres produced water from the Twin Lakes Field in varying percentages, to determine compatibility and their findings are, only one condition results in incompatibility. That is, oxygen in the Ogallala water and hydrogen sulfide in the produced water results in the precipitation of elemental sulphur, possible wellbore plugging, question mark, and severe aggravation of corrosion.

The remedy of that, of course, would either remove oxygen from the Ogallala water, which we believe would be very costly, or to keep the water separate at the surface, which is our plan in the Twin Lakes Field.

Their second finding, they discussed the possibility of formation plugging and conclude, and we agree with them, the deposition of elemental sulphur in formation -- in the formation would be so widespread that if there were any plugging it would be infinitesimally small and in their experiences with waterflood where oxygen-bearing water is injected into a sulfide-bearing formation, they have never been aware of any conclusive evidence that detectable plugging occurs, nor have they seen any differences in injection rates on the same project between waters with and without oxygen.

Q What project allowable does Pelto Oil Company request for this unit?

A In accordance with OCD Rule 701(F)(3), we request that each producing well be granted an allowable equal to its productive capacity.

Q Were all surface owners and offset operators or lease owners notified as required by Form C-108?

A Yes, and I'd like to refer you to Exhibit Number Forty-five and here you'll see that we have -- were able to contact 23 out of the 24 owners of interest within a half mile of the proposed injectors and you'll see there's letters that I've written on August the 19th when it was mailed and then we also have a list of the operators and the surface owners and the unleased mineral interest owners, and we have Xeroxed copies of the certified receipts, return receipts back to -- back to Pelto, and the last page shows tract description and surface owner, and who the operator, lessee, and mineral owners are.

Q Is the unitized management operation in further development of this pool necessary in order to effectively carry on secondary recovery operations and will it substantially increase the ultimate recovery of oil from the unitized por-tion of the pool?

A Yes, I believe it will.

Q In your opinion will the granting of these applications be in the interest of conservation, the prevention of waste, and the protection of correlative rights?

A Yes.

Q And were Exhibits Twelve through Forty-five prepared by you, under your direction, or compiled from company records?

A Yes, they were.

MR. BRUCE: Mr. Examiner, at this time I move the admission of Exhibits Twelve through Forty-five.

MR. STOGNER: Exhibits Twelve through Forty-five will be admitted into evidence at this time.

MR. BRUCE: That's all I have of the witness at this time.

CROSS EXAMINATION

BY MR. STOGNER:

Q The surface owner has been contacted of the initial injection, is that correct?

A Yes.

Q I have one figure I need. You probably went over it but let me go over it one more time.

A All right.

Q What is the present average daily production of the oil wells in this particular pool at this time?

A All right, let me look that up for you. The last information I have, Mr. Examiner, for the total field, in May of 1987, produced 9,705 barrels of oil, 22,215 MCF of gas, and 21,716 barrels of water.

Q Well, is that the cumulative for that year?

A No, that's the last month.

Q Oh, the last month.

A Yes, sir.

Q And what was that oil figure again?

A The oil for the month of May was 9,705. The gas was 22,215 MCF for that month, and the water production was 21,716.

Did you ask for the cumulative?

Q Well, I wanted a daily oil production and that's how many wells, 100 and --

A Let's see, that one would be for -- let me look at my well count here -- for wells that are currently producing, just a minute, I have that here some place. Let me find the well count, or maybe it's back here in the back. Yeah, well count, okay, producing wells for May, 1987, 97 wells for the total field.

Q Does thqt come in under 10 barrels of oil per day average?

A I haven't calculated that but it would be 97 over -- 97 over what did I say, 9705?

Q 9705.

A 9705 divided by 31 times 97, right? Yeah, so 9705 divided by 31 divided by 97, yes, it comes under 5 -- comes to about 3.23 barrels of oil per day per well.

Q Okay. Your participation formula.

A Yes, sir.

Q That was covered in which exhibit? Let's go to that.

A All right, participation formula would be -- it's a long table, Exhibit Thirty-four.

Q Thirty-four.

A Now that's not the formula but that -- the formula is in the unit agreement.

Q Okay.

A So we could dig that out for me, Jim, but the basis for participation is on Exhibit Thirty-four, for each tract 1 through 35, there's 37 tracts, would be that far column called Heavy Ultimate Primary Fraction.

Say, for example, Tract Number 1 has tract's working interest ownership and each participant, then, would get their fraction of the tract's working interest times that fraction and it's -- that's in the agreements spelled out.

Q In the agreement --

A Spelled out in the agreement.

MR. BRUCE: Exhibit Three.

A Is it unit agreement, Exhibit Three?

Q And is that the same as the voting --

A That is the same as the voting for the working interest owners.

Certainly there -- and the revenue side is whatever net revenue that you have against that.

Q And how is that 200 percent to be charged to those nonparticipating working interest owners at this time? The calculated interest formula, how does that come about and how is that being -- how is that going to be --

A Well, the 200 percent will apply to the initial capital expenditure.

Q Okay.

A So -- and that will be the $7.3-million.

Q Okay, now how is that be accounted for on a monthly basis until such 200 percent is reached, and then what happens?

A The -- if a person, if a unit operator does not agree to participate, then a separate accounting will be held for his interest until the amount of money that he normally would have paid of that, say, $7.3-million, has been paid back out the unit proceeds plus 200 percent of what he would have been liable to pay.

Q Will this be kept track of in your office or will it be paid to an escrow account somewhere?

A I'm not sure.

MR. MURRELL: It probably would be set up just in our office as a payout account, as we normally do (unclear) and keep track of this all the time in the Accounting Department.

Q Now I believe some of the interests have not been found, is that correct?

A That's right.

Q Some of the interests, working interests?

A No, the working interests --

Q They have all been found?

A Yes.

Q Okay.

A Some of the royalty interest have not been found.

Q Should there be a time limitation where these noncommitted working interest owners at this time should -- if they elect later on after this hearing, should there be something or some sort of a time limit?

MR. MURRELL: I'm sorry. You say in order to sign these people --

Q Yes, if you give them some sort of a time -- I think of it like compulsory pooling. We usually give them ninety days to join and if they haven't joined, then the 200 percent penalty --

MR. MURRELL: Yeah, I think some reasonable period of time, whatever that may be.

MR. STOGNER: Okay, you're familiar with our 200 or our 200 percent risk penalty in the compulsory pooling, are you not?

MR. MURRELL: Fairly.

MR. STOGNER: I was thinking of -- this is the first compulsory pooling unitization that we've had since these new rules are -- have been enacted. I was thinking of the same sort of procedure in which our compulsory pooling's have in assessing those particular provisions into the unitization.

MR. MURRELL: That would --

MR. BRUCE: That would be acceptable.

MR. TAYLOR: When do you plan to initiate operations?

A As soon as -- well, operations, of course, are many things, but right now we've pre-ordered a lot of material. We're waiting for the order of the unit -- of the State for unitization and waterflood and when that is issued, we're going to be off and running and putting the waterflood in and spending considerable sums of money.

MR. TAYLOR: So it would be effective as soon as its entered, right?

A Will we spend money as soon as the unit's effective?

MR. MURRELL: Yeah, usually within the ninety days, I would assume, we'd either got these people to join or we'd made some other arrangement with these people, or they've just said, no, we're not going to do anything, in which case the penalty would be invoked and they'd be a carried party.

MR. STOGNER: As far as your

waterflood procedure, you followed the lines laid out in C-108 and the standards put on us by the Underground Injeciton Control, is that correct?

A Yes, sir.

Q Okay, and you'll abide by those.

A Yes, we will.

Q And occasional mechanical integrity tests prior to injection, will those be followed and in contact with our District Office in Artesia so that --

A Yes, sir.

Q -- they may inspect such operations?

A We've had very fine support with your office in Artesia. We plan to continue to work very closely with them on meeting all the rules and regulations of the State, yes, sir.

Q Okay. And all of the tubings in the injection wells are to be plastic-coated, is that correct?

A That's right, yes, sir. Fiberglass, I'm sorry, fiberglass lined.

Q Oh, fiberglass lined.

A Yes, sir.

Q It will be a closed system, correct?

A The injection water system on the surface will be closed, yes. The two waters will be kept separate.

Q Now once the main injection -- waterflood injection gets started, have you made provision for water disposal?

A Yes, we're still tied into a water disposal system and we would continue to do that.

Q Do you know if they're able to take the volumes that you will be producing at that time?

A Well, we're hoping, of course, initially that there won't be any increase in water and we'll be putting Ogallala water in, so the little water that we dont' really want to put in the ground (not clearly understood) will continue. Now as the pressure builds up and everything looks fine and there happens to be more rapid water breakthrough, which the system itself might not be able to handle, we're set up to reinject that produced water back into the ground, so we're flexible enough to take whatever the disposal system can or can't take and still want to put produced water, if needed, into the center three or four injection wells as kind of swing wells.

So we'll be able to do whatever we need to do.

Q Okay, and those, the injection -- the reinjection process -- procedure will be an enclosed system, is that correct?

A Yes, it will be, yes, sir.

Q Okay.

MR. STOGNER: I have no further questions. Mr. Bruce?

MR. BRUCE: Nothing further.

MR. STOGNER: Does anyone else have any further questions of this witness?

You may be excused.

A Thank you.

MR. STOGNER: Is there anything further in this case?

MR. BRUCE: No, sir.

MR. STOGNER: Or either, either of these two cases.

If not, Cases Numbers 9210 and 9211 will be taken under advisement.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case Nos. 9210 & 9211 heard by me on 9 September 1987.

_____________, Examiner
Oil Conservation Division