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 VANCO OIL & GAS CORP. AND ITS AFFILIATE CBS OPERATING CORP. FOR AMENDMENT OF DIVISION ORDER NO. R-11,435 TO AUTHORIZE A PRESSURE MAINTENANCE PROJECT IN THE NORTH SQUARE LAKE UNIT AREA, ESTABLISH PROCEDURES FOR APPROVAL OF ADDITIONAL INJECTION WELLS, AND FOR QUALIFICATION OF THE PROJECT AREA FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE ENHANCED OIL RECOVERY ACT, EDDY COUNTY, NEW MEXICO

CASE NO. 12,112

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

March 7th, 2002

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, March 7th, 2002, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 7th, 2002
Examiner Hearing
CASE NO. 12,112

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A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 1:30 p.m.:

EXAMINER CATANACH: All right, we'll all the hearing back to order, and at this time I will call Case 12,112, which is the Application of Vanco Oil & Gas Corp. and its affiliate CBS Operating Corp. for amendment of Division Order Number R-11,435 to authorize a pressure maintenance project in the North Square Lake Unit area, establish procedures for approval of additional injection wells, and for qualification of the project area for the recovered oil tax rate pursuant to the Enhanced Oil Recovery Act, Eddy County, New Mexico.

Call for appearances in this case.

MR. CARR: May it please the Examiners, my name is William F. Carr. I'm with the Santa Fe office of the law firm Holland and Hart, L.L.P. We represent Vanco Oil and Gas Corp. and CBS Operating Corp in this matter. I have two witnesses.

EXAMINER CATANACH: Any additional appearances?

There being none, will the witnesses please stand to be sworn in?

(Thereupon, the witnesses were sworn.)

MR. CARR: Mr. Examiner, I have a brief opening statement.

EXAMINER CATANACH: Please.

MR. CARR: May it please the Examiners, as perhaps you're aware, in 1997 Square Lake Partners determined there were substantial reserves in an area that is now located within the boundaries of the North Square Lake Unit. Devon had a waterflood project in the Grayburg and upper San Andres formations in acreage adjoining what is now the current Square Lake Unit boundary.

Square Lake commenced efforts to implement cooperative waterflood efforts in a project area in the lower Grayburg and upper San Andres formations.

(Off the record)

MR. CARR: Having acquired these interests in September of 1997, they sought approval of 11 drilling permits for infill development in this cooperative area. The BLM approved the permits, but they made the approval subject to obtaining from the Oil Conservation Division approval of the unorthodox well locations.

Because of the large number of overriding royalty interest owners in the area, the Division declined to approve these unorthodox locations until the acreage was unitized.

Thereupon, there was an effort to unitize 4500 acres, which the Square Lake Group owned. And when they went back to the BLM to form a unit of their own acreage, the BLM required that the unit be expanded to include 6155 acres. This meant there were six additional operators, 20 additional working interest owners and 167 royalty owners with whom the Square Lakes Group had to deal.

They spent about a year attempting first to put together a voluntary unit and then to bring together what was needed to come forward with an application under the statutory unitization act. In 1999 they filed those applications.

This is a very old area, and the condition of the wellbores, many of them, is poor; the data is hard to find. And the application for the waterflood project on Form C-108, as you will recall, left much to be desired.

The Division did proceed to approve the statutory unit in June of 1999, but the order provided that injection within the unit area should not commence until the Division had approved the proposed waterflood project.

Sufficient ratifications of the statutory unitization order were obtained, and the unit became effective January 1st of the year 2000. Then, to better focus on specific areas within the unit area, the Division authorized the implementation of a waterflood project in geographic phases.

Order Number R-11,435, issued originally in this case in August of 2000, approved a waterflood project in two specific areas within the North Square Lake Unit.

More recently, data from other secondary recovery projects in this general area show that projects that are under active waterflood are simply not responding as they had intended. When you look at the projects and you see where there is an effective response to EOR recovery activity, it seems to be in areas where the operators are implementing pressure maintenance projects.

So we're before you today seeking amendment of the order that approved the waterflood project to authorize pressure maintenance operations in the North Square Lake Unit.

Today we are not going to re-present the C-108 application that was presented two years ago by GP II Energy, Inc. That's the contract operator of the unit.

Today we're going to talk about why pressure maintenance is more effective than waterflood operations, we're going to tell you what our plans are and what our time frame is.

We're going to call Russell K. Hall. He's a consulting petroleum engineer. He has extensive work in this area. He's worked here for over 18 years and worked for Mack Energy, for Marbob, and has developed techniques to maximize recovery of oil from these reservoirs.

He's going to explain to you why it is that changing two pressure maintenance operations is appropriate. He's going to compare waterflood operations with pressure maintenance operations and will show you that a well managed pressure maintenance project will result in approximately three times a better response than a conventional waterflood operation. He will show you why what we're proposing is, in fact, a valid pressure maintenance project.

We'll then call David Cotner. Mr. Cotner is the president of Vanco. He's going to review the efforts of Vanco and review their plans for the unit. We're going to talk about additional injection wells, we're going to talk about infill drilling, remedial and noncompliance work to bring these properties into line with Oil Conservation Division Rules and Regulations, we're going to identify facility changes that have to be made and what sort of re-routing has to take place to get water to the appropriate injection wells, and we're going to review this in the time frames within which we hope to accomplish these things.

And finally, we're going to present to your our Application for qualification of this project for the EOR tax credit, and we're going to, in the context of that Application, quantify for you the additional recovery that we believe can be obtained from a well run pressure maintenance project in the North Square Lake Unit area.

And at this time we would call Russell K. Hall.

RUSSELL K. HALL,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. Yes, my name is Russell Ken Hall.

Q. Mr. Hall, by whom are you employed?

A. I am employed by Russell K. Hall and Associates, Inc.

Q. And what is Russell K. Hall and Associates, Inc.?

A. We are a reservoir evaluation firm. We are an independent consulting firm located in Midland, Texas.

Q. And what is the relationship between your firm and Vanco Oil and Gas Corp. and CBS Operating Corp.?

A. Vanco and CBS have asked our firm to prepare an evaluation of the North Square Lake Unit and to help them determine what would be the best way to manage this reservoir.

Q. And when did you actually start working on this project?

A. I started working on this particular project about three years ago, I actually looked at it for the first time for Norwest Bank. Norwest Bank had hired me to look at it on their behalf. They were considering making a loan against this property.

Q. Have you previously testified before the New Mexico Oil Conservation Division?

A. No, I have not.

Q. Could you summarize your educational background for the Examiner?

A. Sure. I was graduated from the University of Oklahoma in May of 1978 with a bachelor of science in mechanical engineering.

Q. Since graduation, for whom have you worked?

A. Since then I've worked for Grace Petroleum as a reservoir engineer, for Amoco Production Company as both a reservoir engineer and a production engineer, with Nationsbank and their energy lending group for 15 years, with Southwest Royalties as vice president of reservoir engineering for a year, and I've had my own consulting firm for about five and a half years now, doing reservoir evaluation work.

Q. Are you a registered petroleum engineer?

A. Yes, I am, I'm registered in the State of Texas.

Q. And what other professional associations or groups are you affiliated with?

A. I'm also a member of the society of petroleum engineers and of the society of professional evaluation engineers.

Q. Are you familiar with the Application filed in this case on behalf of Vanco and CBS?

A. Yes, I am.

Q. And are you familiar with the North Square Lake Unit and, in particular, Vanco's plans to implement a pressure maintenance project in this unit?

A. Yes, I am.

Q. You have made an engineering study of the unit in which you have determined what benefits can be obtained in pressure maintenance; is that correct?

A. Yes, I have done that.

Q. And are you prepared to share the results of this work with the Examiner?

A. Certainly.

MR. CARR: We tender Mr. Hall as an expert witness in petroleum engineering.

EXAMINER CATANACH: Mr. Hall is so qualified.

Q. (By Mr. Carr) Mr. Hall, would you initially explain what it is that Vanco seeks in this hearing, and in particular the portion of the case that you're going to be interested in?

A. Sure. There will be several things, but the area that I'm most familiar with is, they will be seeking an amendment of the order which would authorize the implementation of a pressure maintenance project, as opposed to the implementation of a waterflood project.

Q. Before we get into that, it might be helpful if you could review for the Examiners other prior experience you have had working in this area.

A. Okay. When I was with what is now Bank of America, I was involved in a banking relationship with Marbob Energy, which subsequently became Marbob Energy and Mack Energy, and evaluated, starting in 1983, their properties in the Grayburg Jackson field, which is the field located to the south of the subject property.

Q. While you've been working on the area, have you been able to develop techniques that you have actually developed, that enable you to make recommendations on how to most effectively develop the reserves in these reservoirs?

A. Well, what I've actually done in this area was, I was involved in reviewing the reserves, assessing the reserves of projects in this area, on a semi-annual basis for the period from 1983 through 1995.

In particular, I looked extensively at the G.J. West Co-op Unit, at the Burch-Keely Unit, at the Mary Dodd "A" Lease and the Mary Dodd "B" Lease, were the primary properties I evaluated in this area, up until 1995.

During that period, there was extensive development of the properties, and part of my effort was to develop a method whereby we could accurately forecast the reserve additions based upon the operations on these properties.

Q. How has your understanding of what is required for an effective enhanced oil recovery effort -- how has your understanding of what's required changed over the last few years?

A. Well, as I said, when I started looking at this particular project, the North Square Lake Unit, three years ago, the Devon waterflood had begun a few years earlier to the south, on eight sections to the south. At that time it was thought that a waterflood would be a very attractive method to increase oil production, and at that time I basically modeled the results for the North Square Lake Unit on what we expected to see happen on the Devon properties.

Subsequent to that time, CBS Partners and Vanco, Inc., hired me in the summer of last year to review the project and to see if we still felt that that was the best method whereby to produce the reservoir, the best way to maximize field recovery.

What we started learning at that time was that the Devon operated properties were falling significantly below the forecast that we had developed a couple years before. And so the question then became, what is the reason for this, what could we learn from the Devon operations so that we could better manage the reservoir in the North Square Lake Unit.

Q. And what did you do?

A. What we did at that time was to go back and examine all the public data for each well, each -- in the Devon operated properties -- and determine what was happening as far as performance and where could we see deviations from what we expected on the performance, to try to understand what exactly was taking place.

And from that we came up with some analysis that we want to present today, to show what we observed when we looked at the Devon properties, as well as some other projects in the area, as far as how the performance was for the denser well spacing versus some of the original wells. And I think it will help us to really see that pressure maintenance was much, much more effective.

Q. In fact, you've actually done a well-by-well analysis of the Devon unit?

A. That's correct, I looked at it well by well, we looked at the Devon unit from many different aspects. I spent a lot of time there to try to really make certain we understood what was taking place, that it wasn't just an operational problem, that there was just not a lack of interest by Devon any more than, indeed, there really was a reservoir reason to explain why we were seeing the performance that we were seeing.

Q. Did you compare these results with what's happening in other enhanced oil recovery projects in this general trend?

A. Right, I did.

Q. Are you ready to go to Exhibit 1?

A. I am ready to go to Exhibit 1.

Q. All right, let's identify that for the Examiners, and I'd like you to use it generally to -- use it as an orientation plat initially, and then review the information on this exhibit.

A. What we have on Exhibit 1 is a map which shows secondary operations in this general area. Some of these are units, some of these are leases which are operated with secondary operations. The subject unit is in the upper right-hand corner, shown in yellow. The Devon acreage is immediately to the south, in kind of the salmon color.

The property in green, south of that to the right, is the Skelly unit, which is now operated by Wiser Oil and Gas.

If we move further to the west, in the blue color we'll see is the Burch-Keely Unit. A little bit further to the west of that is the Grayburg Jackson Co-op Unit. And in between those properties, although it's not colored in, is where the Mary Dodd "A" and the Mary Dodd "B" Leases are. Those are some of the key properties we're going to look at.

Also, if we go back just to the south of the Devon properties we'll see we have the Turner "A" Lease -- it's in kind of a blue-green color -- and then the Turner "B" Lease is in a light blue color. And those are really the properties that we're going to key on.

I did look at quite a bit of data on these others. These were the properties that we had the best historical data on to do a comparison from.

Q. All right, and what does this exhibit tell us?

A. Well, first of all it shows the orientation of the subject property in relationship to the ones also in this area. There's also some data on here that we could look at. It has information on cumulative oil production and my estimated EUR for each project. And it also has information on what the recovery is per acre and recovery per well.

So there's quite a bit of information on here, most that we probably won't touch on, but the data is here if we did want to examine it.

Q. Are you prepared now to go to Exhibit Number 2, the cross-section?

A. Yes, I think we should go to Exhibit Number 2.

Q. All right. Now, let's go to that. When we look at the North Square Lake Unit, what pool is it in?

A. The North Square Lake Unit is in the North Square Lake Pool, and these adjacent properties are in the Grayburg Jackson Pool. So one of the first questions I had was, are we fairly certain that when we look at the behavior of these properties to the south, that indeed they're analogous to the North Square Lake Unit?

And so what I've attempted to demonstrate with this cross-section -- it's a fairly large cross-section. If you look on the map it will show you the trace. The map is on the left-hand side of the cross-section. You can see the trace that's shown in blue basically goes from north to south. And again, the yellow acreage is the North Square Lake Unit, the salmon-colored acreage is the Devon property.

And what I've constructed here is a north-to-south cross-section, with the attempt to show that we have fairly good continuity of the pays. Now, there's changes in porosity and changes in permeability and reservoir, but indeed we see fairly good continuity of these Grayburg and upper San Andres pays.

And my goal here was to convince myself and be certain that indeed we were looking at the same reservoir and the same reservoir rocks, type of rocks, when we looked at the Devon and the Burch-Keely Unit and the properties in the Grayburg Jackson field.

Q. When we look at this cross-section, it suggests to you that, in fact, we're dealing with the same basic reservoir; is that right?

A. Yes, that's correct. What we see is, we do have the same groups of sands present as we go from north to south. Although we see some thinning and some thickening, we don't just see them actually going away. We see fairly good continuity from north to south. And in fact, one thing that we did discover is, we actually have a general thickening as we go into the North Square Lake Unit area.

Q. When we look at the cross-section, is it fair to say that you can make comparisons between the Devon properties and the North Square Lake Unit because you're dealing with the same reservoir?

A. I believe we can, I believe we --

Q. Even though they're in separate pools?

A. Right, even though they're in separate pools, I think actually we're looking at, in essence, the same reservoir.

Q. So if we're looking at the Devon properties and comparing them to the North Square Lake, we're really comparing apples to apples, are we not?

A. Yes, I feel that we are doing an apples-to-apples comparison when we look at these properties that are in the Grayburg Jackson Pool to the subject property, which is in the North Square Lake Pool.

Q. And if the waterflood operations are disappointing on the Devon acreage, is it fair to assume that they would probably be disappointing in the Square Lake Unit as well?

A. I believe that's a fair assessment.

Q. All right, let's go to the table that has been marked Exhibit Number 3, and I'd ask you to explain how it's organized and what it shows.

A. Okay, and I would suggest that you keep the map handy as we talk about Exhibit Number 3.

Exhibit Number 3 is a table which has information on groups of wells based upon when they were drilled. Now, historically what happened, the Grayburg Jackson field was discovered in 1929. Most of the initial development was completed by the late 1960s and the early 1970s. The field was initially developed on 80-acre spacing. During the late 1960s and mostly in the 1970s, the field was downspaced to 40-acre spacing, and then in the late 1980s and through the 1990s we've seen additional drilling on 20-acre spacing.

So what I've wanted to do is look at, how did the original wells that were drilled on 80-acre spacing and the wells that were drilled on 40-acre spacing compare to the wells that were drilled on 20-acre spacing.

And so what we have here are three groups of wells. The top, shown in red, is the 80-acre wells; the ones in blue are the 40-acre wells; and the ones below that, in kind of the turquoise color, are the 20-acre wells. And then at the bottom is just a summary of all wells added together.

Q. If we move across the exhibit at the top it says "Offset Projects Not Waterfloods".

A. That's correct, these -- What we have here, these properties shown basically on the left two-thirds of this table are identifying projects that were primarily pressure maintenance projects.

And these were projects that did not have a waterflood in the sense that we think of a traditional waterflood where you have a fivespot-type pattern, where you might have a 20-acre location with four injectors surrounding a producer.

Instead, these were properties that had injection wells into the reservoir, but it was basically a pressure-maintenance-type project. There was produced water reinjected, as well as makeup water that was reinjected during some of the life of these properties.

And what we can see from this, what I've attempted to show is, first, if we look at -- Maybe we should just look at the total average first for these offset projects not waterflooded. If we look at that, we'll see the EUR per well is about 133,000 barrels per well. And we can go across here and look at each lease, and we'll see there's variances, but each lease had similar-type performance. Some were a little bit better, some were poor, but we see that indeed we had wells ranging from -- with the exception of the G.J. West, which was rather poor, we see wells that on average produced from about 60,000 to probably about 150,000 barrels.

The real exception to that was the Burch-Keely Unit, where the primary recovery, what I would call the primary, when the wells were drilled on 80-acre spacing, was about 238,000 barrels per well.

By the way, I did prepare this, I went back and looked back at each group of wells, when they were drilled, and forecast this for each of those group separately.

If we go to the table on the right where it says "Offset Waterfloods", these are two projects that were developed on a typical waterflood-type pattern, and they used a fivespot pattern. One was the Devon properties to the south, the other was the Skelly unit a little bit further to the south. And we'll see the average recovery here was 143,000 barrels per well.

So we're looking at similar-type properties. One group had an average of 133,000, one group had 143,000, and that's pretty close.

As we go down the chart we'll see on the 40-acre spacing, we'll see that some of the wells performed, on the 40-acre spacing, performed very, very similarly to the wells that had initially been drilled on the 80-acre spacing.

There are some instances where it was not as -- performance was not as good. In particular was the Skelly Unit. If you see the line there that says "Ratio to 80", that's the ratio of the 40-acre EUR to 80-acre EURs. You'll see on average the Skelly Unit only had 11-percent recovery. There's explanations for this. Unfortunately, everything is not always nice and easy to analyze.

But what happened on the Skelly Unit was, at the same time they were drilling replacement wells, they were converting many of their existing wells, as well as some of these infill wells they were converting to injection. So although we have a well count that shows the wells that were drilled, in reality many of those wells ended up not being producers. And what I reflected here is the total well count. So some of the variations are due to the fact that not all of these wells are producers.

If we continue down and look at the 20-acre wells

-- and this is really the key, because in my mind this is the type of project that we're looking at for the North Square Lake. We're looking at wells that are going to be drilled on a 20-acre spacing. And the question becomes, what's the best way to drill those wells on a 20-acre spacing? Is it with a waterflood project, or is it with a pressure maintenance project? Because the 20-acre spacing is really the given.

But if we look at this -- And the column I would like to look at, I think the one that probably helps the most, is if we see "Ratio to 80". And what we'll see here is that fairly consistently, when we look at the projects that were pressure maintenance projects, when we look across there we'll see that the wells that were drilled on 20-acre spacing by and large produce pretty much about what the wells drilled on 80-acre spacing produce. In fact, the average is 118 percent. So the wells drilled on 20-acre spacing actually recovered slightly more oil than the original wells drilled on 80-acre spacing.

And to me, the thing that was really significant was when we looked at the waterflood projects, we go across there, we see that the recovery per well, when compared to 80-acre, falls off to 40 percent for the Devon waterflood and 39 percent for the Skelly waterflood. So the average is about 40 percent.

So what we're seeing is that we had significantly better recoveries on a per-well basis when we looked at the projects that were pressure maintenance projects than when we looked at the projects that were waterflood projects.

Q. What conclusions can you reach from this --

A. Well, I think there's several. I mean, the most important one is, I think we can reach the conclusion that the projects in this area that were pressure maintenance projects outperformed the projects that were waterflood projects. I think the data here is very clear on that.

I think there's several reasons for that. I think one is, the waterflood projects were somewhat mechanical in nature. In other words, there was an injector drilled on a certain spacing, there was a producer drilled on a certain spacing, without a lot of consideration for the reservoir quality. And I think that's one of the reasons that those projects did not perform as well as they perhaps should have, is because the injection was not always in the portions of the reservoir where it provided the maximum benefit.

For example, on the Devon property, as you go further east on the Devon property, you get into thinner and thinner pays with poorer and poorer porosity and permeability. So there's probably some fairly ineffective injection taking place over on the eastern portion of the

Devon acreage.

I didn't analyze the reservoir properties in the Skelly Unit because that wasn't the immediate offset, but in looking at the data I notice that there's probably injection in the areas that it's fairly inefficient. There's probably some injection that's not sufficient in areas. In other words, there should be more water put in other parts of the field.

And I think that when we move over to these other projects, like when we look at the Todd "A" or the Todd "B" or the G.J. West, some of these other projects, we see they were more efficient because the water was being put in the right places in the reservoir. And it requires a little more, I think, understanding of the reservoir.

So in my mind one of the key factors is, how well do you get in there and understand the reservoir and see where can you get the maximum benefit from injection? Now, where should those injectors be located, and how can you maximize your recovery?

The other thing that I think we see pretty definitely is that waterflood operations did not work the way we would expect a waterflood to work. I don't think we were seeing water banks that were developing with pushes -- with oil being pushed. When we go and look at the Devon properties individually, very few of them show waterflood response. Probably 10 or 20 percent show any kind of waterflood response. Instead we just see typical declines like we would expect to see, had the wells just been drilled without any injection.

Q. Mr. Hall, let's go to what has been marked Vanco Exhibit Number 4. First I'd like you just to identify it.

A. Sure, Vanco Exhibit 4 is a plat showing the North Square Lake Unit, and it also shows the wells that are proposed to be drilled through calendar year 2002. And those wells are shown as red circles, and they're surrounded by the acreage shown in -- kind of a green hachmark is where those wells are located.

Q. Now, I'd like you to refer to this, and using this exhibit, I would like you to explain whether or not this is a bona fide pressure maintenance effort, as opposed to just a large-scale disposal operation.

A. Okay, I think this is a pressure maintenance project for a couple of reasons. One is, and the most significant, is that the water injection is focused in the area where the producing wells are going to be drilled, the 20-acre location wells.

For example, if you look there in Section 31, there's seven wells that are shown to be drilled. You also see there's four injectors right in that area and a fifth one located to the northwest.

Now, what the company plans to do is to make certain that the injection is concentrated in the area where the new wells will be drilled. And thereby you get pressure support in the reservoir to help push that oil into those wellbores.

That's as opposed to as if they had saltwater disposal wells just scattered throughout. And the same thing, as you move up to the northwest, you'll see there's five wells that are planned to be drilled up there, and there's also three injectors right in that area that should provide pressure support for those producing wells.

I think one of the other things that's significant is that we expect -- based upon what I've observed in these other properties further to the east, I expect that we'll have some benefit from the water injection on some of these that are even up to a couple of locations removed. We see that that pressure maintenance does improve recoveries in those wells that are even one or two locations removed.

Q. So the benefits of pressure maintenance extend far beyond just the blue crosshached --

A. I would think so --

Q. -- areas on this map?

A. -- I would think we would see some support in Section 30 from the injection, to the south of Section 30.

Again, it's all going to be dependent upon how much water is put in there and what the permeability is of the reservoir rock, and much of that data is still not really well known.

Q. Now, in terms of benefits from the initial effort, 2002 effort, what kind of data are you going to get? What are you seeking in that area?

A. Well, I would hope that the company -- well, the company does plan -- and I think one of the most beneficial things is, they plan on running a modern suite of logs. Most of the wells that are in this area are older wells. When we look at the logs, we're looking at basically old e-logs or compensated-neutron, gamma-ray-type logs.

We really don't have good analytical tools to help us to know what part of the reservoir is truly pay, where should the water be going into the reservoir, even indeed what part would best be perforated to maximize that recovery.

In this particular case, these are radioactive sands, there's lots of uranium present. The gamma ray can be a misleading tool, the gamma-ray log.

And so having a modern suite of logs, I think, would be very, very valuable in understanding what's taking place in the reservoir.

The company, if I can twist their arm enough, I think they'll core a well, so we'll have a core to help correlate the logs and to examine, then, and determine the true reservoir properties.

Q. With this information, are you going to be able to evaluate the reservoir performance in response to pressure maintenance in a more detailed fashion?

A. Sure. I think anytime you can have more data to help you -- to evaluate the reservoir, you're going to have a better understanding of what's taking place in there.

Q. And to effectively manage this property, is this what you need?

A. You definitely need better data to properly manage this. I don't think with the data that we have, that we can say exactly the volumes of water that need to go in the reservoir, exactly where it needs to go, but I think we can have some generalized ideas that in putting the injectors in proximity to the 20-acre wells, infill wells, that you'll have indeed pressure support there.

Q. With a properly managed and designed pressure maintenance project in the North Square Lake Unit, do you anticipate a response similar to the pressure maintenance response shown on Exhibit 3?

A. That's the table. Yes, I would expect it to -- I would hope that we could have recoveries that would be close to what was experienced by the original 80-acre wells, and I believe these wells produced, on average, about 125,000 barrels each.

Now, we've used a range on that of what we expect the wells should produce, and the actual assignment we've made for reserves is more like 82,500 barrels per well.

Q. Would you get that kind of response with a conventional waterflood effort in --

A. You know, Devon to the south is not experiencing -- They're probably going to recover 55,000 barrels per well on their waterflood performance, and that's only about a -- well, we saw it was 40 percent of what the original 80-acre wells produced.

So I really feel that with the pressure maintenance project you're going to maximize recovery. We've seen that demonstrated when we move to some of these other projects that are truly pressure maintenance projects. And so I think we'll get better recoveries, more oil produced, with a pressure maintenance project than with a waterflood project.

Q. And that's why you need to have this order amended; is that --

A. That would be correct, that's the reason the order needs to be amended, so the company can put in the project that would best manage the reservoir.

Q. Were Exhibits 1 through 4 either prepared by you or have you reviewed them and can you testify to their accuracy?

A. I can testify to their accuracy. I prepared Exhibits 1 through 3, and I have reviewed Exhibit 4.

MR. CARR: May it please the Examiners, at this time we would move the admission into evidence of Vanco Exhibits 1 through 4.

EXAMINER CATANACH: Exhibits 1 through 4 will be admitted as evidence.

MR. CARR: That concludes my direct examination of Mr. Hall.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Hall, the Devon Unit, the one that you say is a waterflood, is directly south?

A. Yes.

Q. And it's the --

A. It's kind of the pink-colored, salmon-colored --

Q. -- Keel West?

A. The leases are the Keel leases and the West leases.

Q. Okay. The other one that you say is a waterflood is the Skelly Unit, which is --

A. Right.

Q. -- directly south of that in the green color?

A. That's correct.
Q. Okay.
A. And these are both developed upon a fivespot 20-acre pattern.
Q. Now, were these units fully developed on fivespot injection patterns?
A. Pretty much fully developed. They have just about the same number of injectors as producers. The number of injectors is just slightly less than a one-to-one ratio.
Q. Now, you don't have that information on this exhibit, do you?
A. No, I do not.
Q. So how do I know how many injection wells that they have in these units?
A. Well, I may have that data right here. What I have here is list of all the wells on the Devon property. In fact, this is the well-by-well evaluation. I can go through and count up how many of these wells have injection into them. We could then know what that number is.
Q. Do you have that data available for each of these projects that you've analyzed here?
A. No, just this one.
Q. Just the Devon?
A. Just the Devon. I could get the injection data

on the other project, but the one that I actually collected it on a well-by-well basis was the Devon project.

Q. So let me ask you this. Say, for instance, on the Turner "A" and Turner "B", you don't know how many injection wells they have?

A. I believe I do have that information.

Q. Okay, I would like that information provided to me.

A. Okay.

Q. I want to know how many injection wells there are on each of these projects --

A. Okay.

Q. -- if you could.

A. Sure. I may have that here. I'll look through my notes, and if I do we can provide that to you.

Q. Okay. Now, when you analyze these projects and you say that some are pressure maintenance and some are waterflood projects, what distinction did you make to make that determination?

A. Basically the pattern of the injection wells. In other words, if the injection wells were not on a uniform spacing like we would see on a fivespot or an inverted ninespot, a spacing like that, I said these were pressure maintenance projects.

Q. Now, if they were not fully developed on a fivespot injection pattern or if there was one or two patterns missing, were they classified as pressure maintenance? I mean, I don't know what criteria you used.

A. Right, I can tell you that on the two properties that I called waterflood projects the ratio of injection wells to producer wells is very close to one to one. If we look at the other projects, the ratio of injection wells to producers is going to be closer to one to four. So they had a very low ratio of injectors to producers.

Q. Is that true for all these projects they're calling pressure maintenance? Was that about the same ratio, 1 to 4?

A. The exception to that would be on the Turner "A" lease. The Turner "A" had replacement wells drilled for all their original 80-acre locations, and so the well counts there are a little bit misleading if we just said, you know, how many wells -- how many producers were drilled, versus how many injection wells were drilled, because originally all the wells were drilled as 80-acre wells. Apparently those wells were plugged out and replacement wells were drilled.

With that exception, the answer to your question is yes.

Q. Now, when you looked at the waterflood and pressure maintenance data from these projects, you looked at what was being utilized at the current time?

A. I looked at the history of each project, as far as which wells had been injectors and also which wells were currently being used as injectors. I also looked at the historical data on injection volumes so I could compare what the produced water volumes were, versus injection water volumes, to see when makeup water was being injected into these projects.

Q. Now, tell me a little bit about the history of these projects. Now, as I recall, and I'm not sure exactly if it's correct, but a lot of these properties were put under secondary recovery operations a long time ago.

A. Yes, in the 1960s and 1970s.

Q. And subsequent to that time they were -- I guess waterflood operations or pressure maintenance operations ceased for a while, and then companies came back in and realized that there was still some additional oil and that they would start these projects back up?

A. I would say that what ceased was the injection of makeup water. In other words, produced water continued to be injected in all these projects, and what we saw was that basically when these projects were initiated, there was both produced water as well as makeup water volumes that were being injected. The makeup water generally was discontinued probably in the late 1970s, but the produced water continued to be reinjected.

The other thing that we noticed on these was that we continued to see increases in water cut, although we never saw a flood response, in other words, where you typically see an increase in a well, where you see an oil bank that's moved into that well. What we did continue to see on these projects was that water cuts would increase with time. And most of these projects now probably have water cuts of 75 to 85 percent, and to me that's indicative of a pressure maintenance project, as opposed to a waterflood project.

Q. Now, did you actually generate production curves for these waterflood projects or pressure maintenance projects?

A. Yes, we did.

Q. And you did not present -- We don't have those.

A. I have them with me.

Q. Now, you testified that you did not see a waterflood response in these projects?

A. We did not see a waterflood response in the sense of a traditional waterflood response where you see an oil bank that develops. Quite often in a waterflood you'll see an oil bank and then you'll see an increase in production.

So typically what we'll have is, you'll have a decline in the primary production, and then you'll have an increase when you see response to the secondary injection, and quite often it will mimic the decline of the primary production. But we did not see that type of performance in these properties.

What we've seen is, when the infill wells, the 20-acre wells, have been drilled, we've seen responses -- or performances much more like the original 80-acre wells. So we didn't see any kind of increase in production like you would typically see in a secondary recovery project.

Q. You didn't see an increase as a result of injection, but you saw an increase in production when they were downspaced?

A. Yes.

Q. Which is natural, which is -- You would expect that?

A. You would expect that. In other words, when you add wells, you increase production.

We also saw -- Now, I will tell you on the Devon properties, I saw a few wells which I believe probably had some waterflood response. But it was a very small number. Most of them I did not see that on.

And in fact, what we observed on the Devon properties was the change of decline -- the decline rate change after waterflood operations were initiated, and the decline is steeper now than before waterflood operations were initiated.

Q. Why is that?

A. I think it's probably because -- without having proprietary data, I think the wells are not pumped off. I think they're producing higher volumes of fluid, and they probably have not installed larger pumpjacks to pump off the wells.

Q. So you really can't tell whether or not they've had a response to waterflood operations?

A. Well, we would expect to see an increase in well production with a typical waterflood response. And on some of the Devon properties I could see that the well might be producing at 10 barrels a day, and then it would jump up to 30 barrels a day and then drop off.

So I mean, there were a few wells where I could see what looked like banked oil, but those were very few. In general, we would see a well that would come in at 20 or 30 barrels a day and then just go on a decline.

And then what would happen was, after a period of time those declines would steepen.

Q. If you do have some of those curves, maybe we can get you to submit those, because I'm really curious, I'd like to see those.

A. Sure.

Q. And did you do those for all of these projects here?

A. I did them for all of the projects that are on this table here.

Q. Now, with regards to what you're calling the pressure maintenance, what did you see in those projects?

A. We saw wells that when they were drilled on the 20-acre spacing, they would have hyperbolic-type decline, very much like what we would have seen on the original 80-acre wells. The initial rates were lower, but we still saw hyperbolic-type declines and with recoveries that probably would average 80,000 to 120,000 barrels per well.

Q. So why, in your opinion, did less injection wells make it perform better?

A. I'm not certain I have an answer to that question. I've asked myself that question several times. I mean, I would think that everything being the same, the more water you would put in the ground and the more it would be evenly dispersed, the better your performance would be.

But what we see from the data is, that has not been the case. And I cannot tell you what's actually happening in each reservoir as to why that's happening, I mean, why is that taking place?

I can tell you the performance, and the evidence from the performance, tells us the properties that were operated as pressure maintenance have done much better than the properties that were operated as a waterflood.

Now, I suspect it may be because the water was being put in places where there was greater benefit to the reservoir, i.e., there's better permeability, there's better pay thickness. It has a greater benefit than if you put an equal amount -- In a waterflood you might put in 300 barrels a day, into each well, whether that well is really benefiting the reservoir or not. I mean, some of it may be going out of zone. And I think in pressure maintenance project you're putting your water into the reservoir where you can maximize your benefit.

Q. Well, isn't that an operations reason, though? I mean, if these waterfloods would have been planned and operated in a more efficient manner, might you not have seen better recoveries?

A. You might have, but I don't know that. I mean, Devon may have done everything they could to maximize recoveries. Texaco may have, on their property. I really don't know the answer as to how they operate their properties.

I am fairly familiar with the Marbob properties and the Mack Chase properties, because I had a relationship with those two companies for over ten years.

Q. Okay, so looking at Exhibit 4, this is the Square

Lake Unit right here.

A. That's correct.

Q. It's outlined in dark blue, I guess.

A. Uh-huh.

Q. Now, do you know enough about what is the plan of the operation going to be in this unit? Do you know what the ratio of producing to injection wells is going to be in this unit?

A. I think -- Well, the plans of the operator are to initially develop it with existing injection wells and then, once they have better reservoir data, to answer that question. So in other words, it's not predefined at this point in time. The thought is, let's concentrate the injection around the new wells that are being drilled. Once we get better reservoir data, we can monitor some injection and see what's happening as far as performance. Then a better plan of reservoir management can be developed.

I would say it's an evolving type plan, which is what it should be. You should take the reservoir data you gain from newly drilled wells and use that to apply to, how should we best manage this reservoir?

Q. So I show about ten existing injection wells within this unit.

A. I think there's eleven.

Q. Okay, I don't see the eleventh one.
A. I see ten on this map as well.
Q. Okay. Those are currently -- Are they being utilized at the current time as injection wells?
A. I do not know.
Q. Okay. Now, the plan is, you've got some red triangles. Now, is it -- Those are going to be wells that are going to be converted to injection?
A. No. They may be, but I mean the original plan -- I mean the plan at this point in time is just to use current injection wells to concentrate the injection around those wells that are being drilled --
Q. Okay.
A. -- and then to go back and re-evaluate this and say, where is additional injection needed? Where are we not seeing response to the pressure maintenance?
Q. Where are the infill producing wells going to be located?
A. They are the red circles. There's seven in Section 31, there are four in Section 29, and there's one on the section line between Sections 19 and 20. They're surrounded by the green hached marks.
Q. So I show that you're going to be drilling 12 producing wells, correct?
A. Twelve wells in calendar year 2002.

Q. So within Section 29 I see that you're going to have one injection well --

A. That's correct. There would also be one in Section 19 and one in Section 20. And again, the plan is to get some better reservoir data, to then go in and say, this is where injection will benefit the most. So I would see this as a minimum indication of where injection will be. But for right now, it's the plan of where to start with injection.

And of course the reason for that is because those wells are readily available. You can use those for injection, see the benefit of the pressure maintenance and then evaluate that.

Q. And what kind of data are you going to be obtaining during this period of time?

A. The logs and the production data.

Q. And what is that going to tell you?

A. Well, if we see -- Let's just take, for example, the well is basically in the northeast quarter of Section 31. If we see that that well has better initial rates than the well that says P-88, which is further to the west, then we can draw a conclusion that we're seeing better support by the pressure at that well, and there needs to be additional injection added further to the west.

But if we see that both wells are performing about the same, that would tell us that indeed the pressure maintenance, the injection of the reservoir, is being felt over a broader area than just one or two locations away.

Q. So what's the plan to bring additional injection wells on? Do you know?

A. I know that the company will study that and then request a C-108 as additional injection wells are needed.

Q. Now, all during this new phase of drilling new wells, the eastern portion of this whole unit is going to be produced; is that correct?

A. I probably ought to let Mr. Cotner address that, since he'll be the successive unit operator.

Q. We don't have any injection wells on that side of the unit?

A. Well, there's another plat that I believe Mr. Cotner will address. It's plans for 2003. This is just the first calendar year, and he has one -- He's going to talk about ongoing operations, and I think you'll see that there's some additional development as you move to the east, planned for calendar year 2003.

Q. Now, from what I can gather right here, your ratio of injection to producing wells is going to be far less than four to one.

A. Well, not all these wells are active. In fact, I think as of today they're all shut in.

Q. All of the producing wells in the unit are shut in?

A. I believe so. So it will be very easy to control which wells are producing and to modify that ratio as needed.

Q. On these pressure maintenance projects, do you have actual maps that show where the producing and injection wells were located, or --

A. I have locations, we could spot the wells.

Q. Because I'd kind of like to compare what patterns they used in some of these pressure maintenance projects and --

A. Okay.

Q. -- some of the things that you guys plan to do in this unit.

A. I think if you look at the offset pressure maintenance units you'll come to the conclusion -- at least the conclusion I have is, there's not a very defined pattern, you don't see real even spacing of the injection wells, because I have looked at that but I don't have a map that shows where all the injectors are at various times.

Q. Now, do you know why that occurred in some of these pressure maintenance projects? Didn't Devon operate some of these other ones?

A. No.

Q. These are operated by --
A. -- Phillips --
Q. -- somebody else?
A. -- they were predominantly operated by Phillips before they were acquired by Marbob. And I do not know who operated it prior to Phillips.
Q. Uh-huh. And Marbob currently operates --
A. Marbob and Mack Energy operate the Mary Dodd "A", the Mary Dodd "B", the G.J. West Co-op and the Burch-Keely Unit, would be the predominant properties they operate in this field. There's other scattered leases, but that's the predominant properties.
Q. And do you know if Marbob has any plans to increase the number of injection wells in these projects?
A. I don't believe they will. They have certainly not done that historically. I mean, they have added injection wells on kind of an as-needed basis where they felt they needed one, but I don't believe that they have any plans to go in and add several injection wells.
Q. How did you guys determine where to drill the infill producing wells?
A. These are basically areas that have higher ϕh than the reservoir. We prepared a map of each of the zones that are on the cross-section, and -- on each well. I mean, I went in and I looked at the logs on each well and

prepared a ϕh for each interval and then added that together so we have a total ϕh map for the reservoir. In fact, it covers both the North Square Lake Unit and the Devon acreage. We do have that map with us.

Q. Well, if you could provide that additional data, I think that's probably --

A. Okay --

Q. -- all I have.

A. -- we would only have one copy at this point in time, because it would be from my work notes, but we could certainly get additional copies.

EXAMINER CATANACH: Okay. Did you have anything, Mr. Brooks?

MR. BROOKS: (Shakes head)

EXAMINER CATANACH: I believe that's all I have of this witness.

MR. CARR: Okay, thank you. At this time, Mr. Catanach, we call David Cotner.

<u>DAVID C. COTNER</u>,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. David Carlton Cotner.

Q. Mr. Cotner, by whom are you employed?
A. Myself.
Q. What is your relationship to Vanco Oil and Gas Corporation?
A. I'm the president of Vanco Oil and Gas Corporation, and I own 51 percent.
Q. And what is your relationship to CBS Operating Corp.?
A. I'm the president of CBS Operating Corp. and I own 51 percent of CBS Operating Corp., both Vanco and CBS Operating Corp., 49 percent of the ownership is held by my partner in New York, former Ambassador William J. VandenHeuvel.
Q. What is the relationship between the two, Vanco and CBS?
A. Well, Vanco Oil and Gas was a company that we set up. I operated a company called -- and was president of a company called Bel-Van. I sold Bel-Van out to Enegex in 1998. That company, Bel-Van, had oil and gas properties, as well as pipeline systems and a processing plant. I spun the oil and gas properties off into Vanco and sold the pipeline and the processing plant to Enegex. So Vanco was set up to own and operate those properties, and it has continued to do so till today.
CBS Partners was set up for the Square Lake --

acquisition of Square Lake Partners and -- who owns 80 percent of that unit.

Q. Have you previously testified before this Division?

A. No, sir.

Q. Could you summarize your educational background?

A. Yes, sir, I have a BS in petroleum engineering from Texas A&M University, class of 1976.

Q. And since graduation, for whom have you worked?

A. I worked for Shell Oil Company for five years as a production engineer, three for -- operations foreman in the Denver unit for a year, and as a reservoir engineer in Houston for a year.

Q. You're familiar with the Application filed in this case?

A. Yes, sir.

Q. And you're able to review for the Division Vanco's plans to implement a pressure maintenance project in this unit?

A. Yes, sir.

MR. CARR: Are the witness's qualifications acceptable?

EXAMINER CATANACH: They are.

Q. (By Mr. Carr) Mr. Cotner, would you summarize for the Examiner what it is that Vanco seeks with this

Application?

A. Yes, we want to -- We're seeking an amendment to the original order that had authorized implementation of a pressure-maintenance project, water injection, utilizing initially the existing wells on the property.

We're seeking to further amend that order such that we could make individual requests for additional injections through the C-108 process on an as-needed basis, with the understanding that we would perform an area of review of half a mile and take care of any remedial work within a half-mile radius of any future injector, as proposed.

And then thirdly, we seek to qualify this pressure maintenance project for the recovered oil tax rate, pursuant to the New Mexico Enhanced Oil Recovery Act.

Q. In my opening statement I reviewed the general background history for the unit. I ask you at this time to provide the background on Vanco's efforts to acquire interest and move to the position you are today where you're hoping to be able to develop this area.

A. Yes, sir. Again, Vanco Oil and Gas, we came in the first quarter of 2000 and purchased 11-percent working interest in the unitized area. This was prior to the finalization of the C-108 Application for injection. We did that with the idea that we would participate in the development of the unit.

Subsequently to that, the injection order was approved in August, and so we were ready to go to drilling, and problems that had arisen between the contract operator, Square Lake Partners, and their financers had put us in a stalemate since that time. We're still in a stalemate today.

Do you want me to just keep going?

Q. Following the acquisition of this working interest, have you -- the 11 percent, have you attempted to acquire additional working interest in the unit area?

A. Yes, and to kind of, I guess, keep it in chronological order, we had the 11 percent, we're in this stalemate, we have this problem between the financers, the working interest owners and the contract operator because of a lien that existed. And the way it was financed was -- it failed because of this long period of time it took to get the unit to where they could develop it, and it's a very marginal property.

So the idea was to form CBS to come in and to -- and we did come in, and we secured agreements with Square Lake Partners by their interest with GP II Energy, Inc., the contract operator, to pay off his lien, and with Range Resources, who's the financer, to pay off on agreeable terms their note.

I had these agreements in place, we began the due-diligence process, and through this due-diligence process we unearthed more problems than we were aware of prior to commencing this, and --

Q. Now, those problems, they include the disappointing results on the project that Devon operates; is that correct?

A. Yes, one of the -- you know, the Devon project was our analogy project, and when I bought the 11 percent to participate in this, that was kind of their crown jewel that they were going around bragging about, and it looked like it was going to be a successful project.

Since that time we've cut their reserve estimates in half. The property is currently for sale. And so, as Russ discussed, we went in great detail to see what was happening.

And of course we're holding this up to potential investors, financers, to say, you know, we're going to do the same thing they did. And when we updated the data we said, gosh, that's not the best thing to be claiming, and why, and what do we need to do different? And so that was one issue.

The other issue that came up was, we became more intimately familiar with the order and the things that the original order required. And in light of Devon's results and our findings related to studying that, we decided the initial order was not practical. And so that's why we're here today.

And then on top of that, as you all are probably aware, there has been a notice of noncompliance given to GP II, seeking to set penalties for approximately 20 unit wells that had been inactive for over 18 months.

And in addition to that, there's another 23 wells that GP II operates in this same area that's owned by Square Lake, and so that's yet another outstanding problem.

So we're not in a position to be able to go forward without getting the order amended and working out some agreeable basis to address this noncompliant work.

Q. What is the relationship today of Vanco to GP Energy, Inc., and the other working interest owners in the North Square Lake Unit?

A. Okay, since -- Again, Vanco owns 11 percent. CBS Partners has bought five percent of the unit, and they own five percent of the unit.

Square Lake Partners owns 80-percent working interest in the unit, and they have designated me their representative for this hearing today.

GP II Energy, Inc., is a contract operator who owns no interest in the unit or any of those properties, and they've also designated me as their representative here today.

Q. And those designations are what has been marked as Vanco Exhibit Number 5; is that correct?

A. Yes, sir.

Q. So today through these designations you represent what percent of the working interest in the unit?

A. Ninety-six.

Q. You also have been designated to represent the unit operator; is that correct?

A. Yes, sir.

Q. And you own what percent of the working interest in the unit?

A. Vanco owns 11 percent, and CBS owns 5 percent.

Q. A minute ago you identified the obstacles to what you're trying to do, a new order and working out the noncompliance issues. If you are successful in getting these resolved, what is going to happen to unit operations?

A. Well, GP II Energy has agreed to resign as operator, and CBS Operating Corp. or Vanco Oil and Gas will come in and take over operations of the property. We propose to post the standard bonds, and in addition to that we propose to post a bond of $195,000 as assurance against the noncompliant issues that we're taking on.

Q. And the amount of that bond was determined how?

A. The District Office in Artesia, when we asked them about the transfer of operatorship, that's the number that they gave us, based on the wells that they had on their list just being problem wells and noncompliant.

Q. At that point in time either Vanco or CBS would be operator, and you'd be responsible for performing the unit obligations?

A. Yes, sir.

Q. When was this unit actually formed?

A. Well, it was effective January 1st of the year 2000.

Q. And what is the current status of the unit?

A. Well, the current status of the unit is --

Q. You might want to refer to Exhibit 6, which is a base map of the unit area.

A. I guess I should point out while we're at this juncture that there's no fee lands under the unit. Roughly 90 percent of the unit is federal lands, and 10 percent of the unit is state lands, being designated there -- the federal lands are in the dark yellow, state lands are sort of off-white.

Q. All right, what's the status? This exhibit shows, first of all, the unit boundary as the dark line, correct?

A. Yes, sir.

Q. It shows certain of the offsetting tracts. How many wells are in the unit?

A. Currently there's 91 total wells in the unit, there's 48 producing wells, there's 33 inactive producers and there's 10 injection wells.

Q. What kind of production rates are currently being obtained from this entire unit?

A. I guess we should distinguish current, because as of today every well in the unit is shut in because of the disagreements between the contract operator, Square Lake, and the financer. So current will go back a month.

And based on October's production when -- business as usual, the current unit production was 109 barrels of oil a day, 400 barrels of water a day, and zero gas.

Q. And this is the total production from all of the active wells in the --

A. Which would have been 48 producers at the time. And again, the problem is that this very big unit, relatively high number of wells, and there's a negative cash flow associated with the unit based on current operations.

The estimated reserves for the unit, remaining reserves under economic basis, is only 206,000 barrels of oil, is all the remaining economic reserves for the unit.

Q. Under current operations?

A. Under current operations, yes, sir.

Q. Let's talk for a few minutes about your plans for unit operations if pressure maintenance is approved.

A. Yes, sir.

Q. How far out have you developed fairly concrete plans, how far into the future?

A. Well, I guess what we've kind of come up with is, in answer to your question, two years, and what we try to do and what we have to show today is kind of a minimum two-year plan. Obviously, you know, we could do more, but we wanted to -- we've got a fairly aggressive plan on some basis but, you know, it would be possible to do more work. We propose this as our minimum objective.

Q. Through 2003?

A. Yes, so essentially two years.

Q. And the information you gain and the experience you have between now and the end of 2003, is that what you're going to utilize to fine-tune and develop the plans for the project after that date?

A. Yes, sir, the idea is that we need to gain information to know what is the best way to manage this reservoir and to optimize recovery.

Q. When we look at your plans, they fall into certain definite categories or areas, isn't that fair to say?

A. Yes, sir, the -- well, the plan is this year to drill -- we're going to -- the areas are infill drilling, adding additional injection wells, doing remediation of the noncompliance wells that are there on a mutually agreeable basis that we hope to work out with the District Office. We have facility work to do, and then we have also re-routing of lines so that we can concentrate the injection in the desirable areas.

Q. In terms of re-routing the injection to desirable areas, is it your intention just to continue to operate the existing injection wells as they have been operated in the past?

A. No, sir, the idea is that the drilling is going to give us new data that's very important. As Mr. Catanach mentioned, you know, these areas have been waterflooded in the past. In fact, there's a cooperative waterflood on this area. So there's a whole host of factors that control this reservoir and that need to be fully analyzed. So the modern logs are an essential part of it to gain saturation information, lithology information.

And then in addition to that, we want to focus and concentrate our injection in the area of the new wells and analyze the results of that injection to see, in fact, do we see banked oil, or is it more of a pressure maintenance, which is more of a -- I think at Shell we used to call it a drag, you know. Instead of a sweep, it was more of a drag.

And you know, those are things that need to be analyzed. And really, the only practical way to do this is to have the flexibility to adjust our plans as we learn and gain the engineering information to develop it.

Q. Let's break this down. Let's take a look at what you would hope to accomplish during the first half of the year 2002.

A. Well, unfortunately time flies. So the first thing in 2002, we hope to have a successful order establishing our requirements so we can move forward. That's why we're here today.

Assuming we get that order, then the idea would be to also get an agreement on a mutually agreeable basis for addressing the outstanding and existing noncompliance work in the unit. We'd coordinate that with the District Office.

Based on the order and that agreement, we'd then be in a position to post the $195,000 bond, succeed GP II in operations, and then our first step would be to get on the ground. The strength of this property is, because of all the contention that's between the parties, it's not been well managed. We're going to need some time to really establish what's there, how bad things are, you know, what potential upside is there. And so that's going to be sort of an education phase, is a hands-on, on-the-ground, how-would-an-Aggie-do-this? kind of a thing, I suppose.

Then based on that -- and during that same time we'd want to again, I guess, confirm based on those findings -- work with the District Office and kind of confirm on our schedule which wells we'd address first from a noncompliant issue.

At the same time we'd be following the NOS filings for the infill wells that we plan to drill in the second half of the year.

Q. Okay, what about the second half of the year? What are you going to do then?

A. Well our plans would be to drill a minimum of 12 wells, which were identified on that Exhibit 4, I believe, that you all talked about earlier, which basically had seven kind of in the southwestern part and five in kind of the north -- in Section -- mostly in Section 29. So we'd drill those infill wells.

At the same time, we would continue the remediation of the noncompliant wells. We would gained that engineering information from the drilling of the wells. We plan to focus the injection in the areas of the infill wells so that we can begin observing what kind of response we see from injection.

And again, I think that the answers -- some of what was being discussed with Russ, kind of -- our plans are that there's probably going to need to be one injector for three producing wells.

The thing I'd like to point out is that, you know, of course today there's no producers, but the production from this unit is -- you're looking at less than a half a barrel a day, and the withdrawal rate is extremely low. And, you know, we need to operate as a unit, that is a good reason for it to be as a unit, and managed as a unit.

And that count, you know, maybe at the end of the time it's meaningful, but we can't predict what it should be at this point, we need to gain the information. We're going to focus the water, we have the new wellbores and the new areas so we can make projections of what to do in the other areas in the field.

Q. You're going to continue the noncompliant work?

A. Yes, sir.

Q. You're going to have to do something with existing facilities, are you not?

A. Yes, sir, what we plan to do in that regard is put three central batteries in, probably two by the end of 2002. We'd put one down in this group of new wells in Section 31 and one up near the wells in 29, and then ultimately we'll put another central battery in, over on the east portion of the field.

We visited with Navajo Refining, and their lines are in the area. We plan to put three LACT units in so that we have a custody transfer on the property, minimize trucking, maximize oil price. Also we'll have central batteries, which, you know, is one thing that unit operations certainly facilitate, and just allows us to optimize the property. So that work is also going to be part of it.

And then to the extent we need to modify the injection to get injection into these -- and concentrated in the new areas, we'll be doing those changes in 2002 also.

Q. All right, and that's the work that is shown on the Exhibit Number 4 that Mr. Hall reviewed?

A. Yes. And one other thing that I -- having the luxury of sitting over there and sitting to the questions and kind of responding to this, the other thing is that there's going to be -- having had, you know, the initial injection in the field and we'll drill these new infill wells, that's going to significantly increase the amount of water to be handled. And so that will allow us to -- we'll get an increase in injection rate just from the fact that we're doing all this additional drilling.

So that will significantly change the existing operations where there's only 400 barrels of water a day available in the unit at this time, so...

Q. Let's go now to what has been marked as Exhibit Number 7, the 2003 development, and I'd like you to review what your plans are for calendar year 2003.

A. Yes, sir, in 2003 you can see that step out to the east side of the property. And as Russell mentioned, there's kind of three sweet spots developed where we have more ϕh, more net pay in the area, and the third of which is over kind of on the east side. Again, we feel like by the time that we get the order, we take over operations, we're only going to have six months in 2002 to -- and there's going to be a lot to do.

And so then what we propose during 2003 is essentially, at a minimum, to drill an additional 12 wells and to install, at a minimum, four additional injection wells, which you see, two of which are in the section -- well, one in 29 and one in the south part of 20, which will kind of encompass that area, and then two over in the new area, on the east side. And again, that's kind of a minimum thing that we want to -- We feel like that at a minimum we'll have to do that or need to do that.

And then we'll add additional and propose additional based on the results that we have in the first unit, if we have that results. Sometimes results take more than one year to really fully understand the impact.

Let's see...

Q. With this information that you're going to get from the 2002 and the 2003 development efforts, you then will be able to finalize plans for subsequent years, additional infill drilling, additional injection; is that right?

A. Well, I kind of feel like that what we will do is, we'll take that information and we'll kind of move a year at a time, that, you know, it will be an ever-evolving process, and if we're doing our job we'll be getting smarter every day that we're out there.

And the idea is that we feel like there's up to 50 producers that can be drilled on this property, and so based on these results, you know, we plan to further develop the property, fully develop the unit with 50 additional wells and whatever injection is deemed necessary, based on the engineering and the results of this injection.

You know, it may in fact be that some spots will look like a fivespot. You know, until you get there and do it you just -- you know, we don't know, we can't predict the future unequivocally.

Q. At this point in time when we look at your infill drilling plan, in the year 2002 you're going to drill how many additional infill wells?

A. Twelve infill wells.

Q. And in 2003 how many more infill wells?

A. Twelve, on a --

Q. Did you testify that you initially have a ratio of producing to injection wells of 1 to 3?

A. We think that that's going to be about the appropriate number, yes, sir.

Q. And then with the information that you get from this initial development effort and subsequent efforts, you may further refine that or adjust that; is that --

A. Yes, sir, that's true. And if we deem that we need more water, we've got an agreement with Devon to buy makeup water from Devon. So that's available to the extent we determine it's appropriate.

Q. Now, as to your injection plans, you're going to use the current injection wells, the current ten wells, correct?

A. Well, we're going to use some of them, I don't know that we'll use all of them. Again, the concept is to focus the injection in the area of the new wells and try to make that our pilot, our study area, and then expand from there. So probably the wells on the western flank of the -- far western flank of the unit may not be used initially, depending on the water volumes and injection rates that we can establish. But the idea is to really try to gain information where the new wells are, to determine what's the best way of managing the reservoir.

Q. And then in 2004 you want to add four additional injection wells, at least that number?

A. Yes, sir.

Q. And you would bring C-108 applications to the OCD on each of those and do the related remedial work?

A. Yes, sir, we request that that be permitted to be done on a per-well basis within the standard half-mile radius of review.

Q. As to the remedial and noncompliance work --

A. Yes, sir.

Q. -- currently there are a number of wells that are pending before the Division on a case docketed later this month --

A. Yes, sir.

Q. -- are you aware of that?

A. Yes, sir.

Q. And we are going to request that those wells in that case be continued, pending an outcome in this case; is that correct?

A. Yes, sir.

Q. When we -- Once you become unit operator, you're going to file a change-of-operator form?

A. Yes, sir.

Q. You're going to post $195,000 additional plugging bonds, over and above the base bond?

A. Yes, sir.

Q. You are going to run integrity tests as required on the wells?

A. Yes, sir.

Q. And you're going to come to the OCD and work out with either the District or Santa Fe a schedule to meet the remedial and compliance requirements of the Oil Conservation Division?

A. Well, chronologically I'll probably do that before I post $195,000, because if we can't work out something agreeable I may not be wanting to assume that responsibility.

Q. So what you're going to do, then, in addition to this is, you're going to refurbish the facilities?

A. Yes, sir.

Q. And then going to be re-routing lines to get water to the injection wells where you can get the best response and the best information; is that a fair summary of what you're going to do?

A. Yes, sir.

Q. And that's what you're planning to do between now and the end of 2003?

A. Yes, sir, and it really gives us 18 months, so...

Q. Now, would you refer to what has been marked as Vanco Exhibit 8, the EOR Application? Would you just identify that?

A. Yes, sir, this is our Application for the enhanced oil recovery qualification for the recovered oil tax rate at the North Square Lake Unit.

Q. Does it contain the information required by the Rules of the Oil Conservation Division for the qualification of these projects?

A. Yes, sir, it does.

Q. What is the estimated additional capital cost to be incurred in the implementation of this project?

A. $18.5 million.

Q. And what are the total project costs?

A. $35,400,000.

Q. How much additional production does Vanco expect to obtain from this enhanced oil recovery project?

A. Yes, sir, we anticipate recovering 6.74 million barrels of oil and 5 BCF of gas.

Q. And have you estimated the total value of this additional production?

A. Yes, sir, based on a $20 flat oil case, an equivalent basis of 5 standard cubic foot per barrel, we estimate the total value of that production to be $144 million.

Q. Now, how is Vanco proposing this pressure maintenance project be implemented?

A. Let's see, we have an exhibit for that, don't we?

Q. Exhibit A to --

A. Excuse me, these are out of order, let me -- Mine are backwards.

As you can see on Exhibit A, basically there's a north-south line that essentially splits the property in half, and the idea is that we would apply for the credit on the west half where the initial injection is going to occur, and then on the east half once we begin pressure-maintenance operations on the east half of the property.

So we've split the property in the two areas and are seeking the tax credit on the areas that are actually impacted by the injection.

Q. That's Exhibit A to the EOR Application, correct?

A. Yes, sir.

Q. Exhibit B to that Application is a list of the wells in the unit area; is that correct?

A. Yes, sir, it is.

Q. And then Exhibit C is a type log which identifies the injection interval?

A. Yes, sir, it is.

Q. Okay. Would you refer to Exhibit D to this EOR Application and explain what that is?

A. Exhibit D is a forecast, or I guess a production plot, rate versus time, and what it depicts is the existing production in the field and our forecast, beginning in the year of -- from 1990 through current, and then shows the response to our infill drilling and pressure maintenance project.

And as you can see, that ratchets up over about a three-year period there where we would be drilling the infill wells and initiating the pressure maintenance.

Q. And this in a graphic form shows the 6.74 million stock tank barrels of oil that you're going to be receiving from this project if it is successful?

A. Yes, sir.

Q. Is Exhibit 9 an affidavit confirming that notice of this Application and hearing were provided in accordance with Division Rules?

A. Yes, sir.

Q. And to whom was notice provided?

A. To all the working interest owners in the unit.

Q. How soon does Vanco or CBS hope to assume operations of the unit?

A. Well, we would hope to be able to assume them in May, but hopefully no later than June so we can get going with our project.

Q. And at the current time the project is shut in?

A. Yes, sir, pending some agreement.

Q. Do you believe that it will remain shut in until these issues are resolved here and with the other interest owners?

A. Well, it's going to remain a problem, whether it remains shut in or not, I can't say. But there are significant problems that have to be addressed, and there's really no means to address this in the absence of the project going forward. The property is negative cash flow, and it needs attention.

Q. Mr. Cotner, in your opinion would approval of this Application and the implementation of the pressure maintenance project in the North Square Lake Unit area result in the recovery of hydrocarbons that otherwise would be left in the ground?

A. Yes, sir.

Q. Would approval of this Application and the implementation of the project otherwise be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. Absolutely.

Q. Were Vanco Exhibits 5 through 9 prepared by you or compiled under your direction?

A. Yes, sir.

Q. Can you testify to their accuracy?

A. Yes, sir.

MR. CARR: May it please the Examiner, we would move the admission into evidence of Vanco Exhibits 5 through 9.

EXAMINER CATANACH: Exhibits 5 through 9 will be admitted as evidence.

MR. CARR: That concludes my direct examination of Mr. Cotner.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Cotner, how many working interest owners are there in this unit? Do you know?

A. As of this week, there's no one else that owns over 1-percent interest. There's approximately 10 outstanding interest owners besides my two companies and Square Lake Partners. Some of those interests are incredibly small, like .00002. Again, those ten people comprise a total of 4 percent, and that's just a -- I'd have to look at the -- to get you the exact number, but that's close.

Q. Okay. The royalty interest in this unit is basically state and federal, correct?

A. It's 90-percent federal, 10-percent state --

Q. Okay, and --

A. -- if you want it exactly, it's 88 federal, 12-percent state, I think.

Q. Okay, and there are some overrides in here somewhere?

A. Significant overrides.

Q. So you don't know at this point -- besides drilling the additional infill wells, you don't know which other wells within the unit will be put on production at this point?

A. No, sir. I, you know, think that chances are more than likely, we'll produce the infill wells, and for the injection wells we'll convert existing producers to injection wells.

Again, I'm not satisfied sitting here today which wells are economic in the unit. Because of the way it's been managed, it's going to take some time on the ground to really establish -- If we look at the decline curve we can see some fairly significant decline in the last three years, and it's just going to take some determination to tell what production truly is economic.

But essentially I would say that ultimately the majority of the production will come from the newly drilled wells and that the existing wells will largely be used for injection or be TA'd or PA'd.

Q. Okay. Now, if I'm an interest owner -- Just for example, if I own some interest in Section 25 on the western part of the unit there, am I going to share in production from the new producing wells?

A. Yes, sir.

Q. And that's based on what?

A. Unitization, I mean that's what unit is. You could produce all your oil from this one corner over here, and every owner in this unit shares in that oil on a basis that's been established by and ratified by the requisite number of owners in interest in the unit.

So that's -- Basically, this whole unit is a lease, so that if -- where something happens does not deprive anyone or enrich anyone. Location is just not even an issue in that respect, sir.

Q. Do you know what the allocation formula was based on, Mr. Cotner?

A. I could take a bit of a guess on it. I think it had something to do with cum and also projected remaining reserves. I could look it up, but I don't purport to know it exactly. But I'm pretty sure it's a split formula.

Q. So you're saying that every interest owner in the unit is going to share in the production, according to this formula, in every infill well that you drill in here?

A. Yes, sir.

Q. Okay. Now, initially -- You don't know how many injection wells you're going to use initially?

A. Ultimately. Initially, if you go back to that exhibit, Exhibit 4, we know that we'll use all of the injection well -- really, the only two in question on Exhibit 4 are the two in 25. We probably would not use the two in 25, and possibly not the one in the far northeast corner of 20. Other than that, we would anticipate using all of the existing injection wells. So we would use seven of the existing 10.

Q. So initially you'll be using seven injection wells, and you'll have about 400 barrels of water a day to put away, plus whatever you get from the new infill wells?

A. Well, you know, timing is -- Yeah, plus what we're getting from the new infill wells, exactly.

Q. So -- And you don't know what that might be?

A. Well, I think that's going to be -- And I have a bubble map with me, I could show you the previously injected volumes, but -- Boy, if I knew that I'd probably be in Hawaii on an airplane if I could predict the future that well. I think it will be in the range of 100 to 200 barrels a day, and hopefully the oil will be a like rate. You know, obviously we won't know till we drill the wells as to what we're ultimately going to get.

And there's going to be some variance there for different reasons besides pay, you know, prior injection and those sort of things

Q. So you think with the new infill wells that you'll have enough water production -- I assume you're not bringing any water in?

A. At this point we don't plan to, yes, sir.

Q. So with the new infill wells, do you think you'll have enough water injection to have an effect on the reservoir?

A. Yes, sir, based on Russell's studies of the other fields, I think we will. It will impact the immediate surrounding areas more so than the others, but that's going to be part of the study process, is to evaluate that and to see how much water is really necessary.

I think that's what we really see in these other projects, is that where a lot of that production went is, they're converting producers to injectors. They would have recovered more oil if they had left those wells they converted to injection as producers, and that's one of the reasons their performance is substandard. We predict that they lost over 1.5 million barrels of reserves by converting new producers to injectors.

And so I think that that really is, in my mind, one of the distinguishing facts between the way these other properties have been operated and the way Devon's operated theirs.

I've been on the ground out there. They didn't spare any expense. I mean, they spent a ton of money to develop this on a full-fledged, fully developed fivespot waterflood, with the idea that they were absolutely doing the right thing. They've cut the reserves from 22 million to 11 million in their annual reports, you know, the property is up for sale, you know, they just have not operated the property as efficiently as these other units.

And I don't want to sit here today and tell you unequivocally that I'm not going to have a fully developed fivespot. I will if I feel like the engineering and the results justify it and maybe do that in certain areas, but not in all areas. I need to have the flexibility to adapt and to apply engineering techniques and to maximize recovery for myself as well as all the royalty owners.

Q. Now, that's what Devon did in that unit to the south, they would drill new wells and instead of producing them, they would convert them to injection?

A. Some of the wells, sir.

Q. Okay. Well, that's not -- You're not even considering that in this unit?

A. I'm not ruling anything out either. I just need to get started, and we're going to apply the best engineers -- You know, I've got a great engineer in Russell, you know. I've been around the block, I've had a lot of experience. You know, we're going to operate and manage this thing in a prudent manner, and we want the flexibility to adjust as engineering dictates.

If Devon suddenly starts having -- You know, we're going to continue to study the Devon project, we're going to learn something from that. We're going to use all the information available to do the best job that we can for our royalty owners and ourselves and our other working interest owners.

Q. Now, some of these sections, at least for a couple of years, I mean some of the areas within the unit, there may not be any activity at all; is that correct?

A. Yeah, I think that that's -- well, you can see the plan, I mean -- and again, it has something to do with the quality of the pay. Obviously we're going to start with our best foot forward, and we're going to develop the areas where we think we have the best potential, so that's how this is focused.

I think that, you know, some of the wells, you know, are -- probably won't see much pressure response. Again, we don't know the answer to that, but we split it in two pieces because of that very fact, that we're not even going to do anything in the east half from a drilling standpoint or an injection standpoint till 2003.

And again, also remember, we kind of look at this as a minimum. If you'll remember when I came and met with you and Lori, we had a lot more aggressive plan, and there's a good chance that we could be much more aggressive, and that's going to be partly dependent on the results of the 2002 and -- when I get to go to work.

Q. Okay. Tell me -- you drill an infill well, and -- say the area in Section 31, you drill an infill well, and you get a producing rate, whatever it may be. How do you know what effect injection is having on that producing rate, as opposed to a well that you drill that may not have -- may not be surrounded by as many injection wells? I mean, I'm just wondering, how do you know that the injection is having an effect on that well?

A. Yes, sir, I understand your question and I sense, you know, where you're coming from, from the questions you ask for us, and I think it's a good question.

And how we'll know is -- and what Russ alluded to is that we have this typical-shaped curve, the hyperbolic curve that you're familiar with. And you go into these wells and you have a hydraulic fracture, and the radial -- the hyperbolic curve is -- essentially you have linear flow, quasi-radial flow and then radial flow. And we have this shape that we anticipate seeing.

And one of the reasons we thought Devon's deal was such a great deal was, hey, you got the waterflood on top of this good infill development program and you've got this nice big kick here, and Russ projects that out. But it didn't flatten out, it just kept going like this. And we say, that's not what we want.

And so what we are going to do is, we're going to drill these infill wells, and some of them are going to be closer to an injector than others. We're going to compare to see how the shape of that curve and how that decline is different from the well right next to it, to the well next to that, and the well next to that, and the well next to that.

We'll study these curves, we'll analyze that, and we'll say, gosh, the ones right next to it are doing a lot better, we need more injectors. Or if we say, hey, the well three locations away is doing just as well as that well, let's don't put any more -- let's put more producers and not as many injectors. And that's the information we'll gain from this.

Q. And do you think that you'll have enough short-term information to where you could analyze that? I mean --

A. Well, it's going to take some time. You know, it has to do with the compressibility of the fluids, the permeability of the rock. And, you know, the difference what Russ is talking about as far as a traditional waterflood where you build up a bank of oil and you have water behind it and this big wave comes in and get that standard -- that just doesn't seem to work in this rock.

And this rock -- these zones that we're looking at, we're looking at 20 to 50 foot of pay that's over a 300-foot interval. So I think that explains a lot of the inefficiency of conventional waterflooding and why you need to really be smart about where you put it.

So in the answer to the timing of it, it may be several years -- Devon's been waterflooding for five years now, and they just know enough that they want to sell it. You know, I don't know that they couldn't do some thing that are better, but you know -- This property has been around since the 1950s, so we don't want to put ourselves in such a huge hurry that we're doing stupid things and spending money needlessly. And we don't want to do things like convert wells to injection when they could have made 100,000 barrels of oil and now there's going to be, you know, an injection well that doesn't benefit anything.

But I think the answer to your question is that that is one of the things we're definitely going to be interested in, is, how do the wells perform differently one location away, two locations away, three locations away? How close do we need to be, where do we need to focus it?

And then as we increase and we move out of these sweet-spot areas, it's going to be the same sort of analysis. And it may be that we need more injection in areas that have better pay quality and less injection in areas that have lower pay quality.

Q. I guess one of the things that I'd be concerned about is just leaving it open-ended to where you guys could just take off from here and then go wherever you need to go or wherever you think you need to go, I mean, for years to come. I don't know if the solution to that is to maybe bring you guys in maybe on an annual basis and you can give us an update on what's going on and what your plans are, and --

A. I sure will. Santa Fe, they've got great food.

And also, David, Mr. Catanach, the thing about that is, we do plan to submit an annual development plan. I brought one with me last time I came.

You know, essentially that's what the order has in it now. We've got essentially a two-year plan. That's something we plan to address and update annually. Trust me, I've got a lot invested in this property. I want to maximize the recovery. You know, I'm interested in making money for myself and my partners.

Q. The waterflood order that we issued in the previous case, I don't know how many injection wells we approved in that order.

A. Twenty-three.

Q. Now, what do we do with those? Are you just dismissing those as not -- you're not going to convert those wells to injection?

A. I'm not dismissing anything. What I'm saying is, I need to get started, and let me figure it out, and then we'll come in and come see you every time. And we're going to be coming back. I mean, I can't rule them out. At this point, we're not planning on using those wells.

Q. At this point you're not planning on using those wells --

A. Because they're not -- you know, in other words, we're going to use the existing wells on here for this first tranche. Then the second tranche we add -- and I don't know the answer to whether these two -- or these four were in that 23, Mr. Catanach, I really don't remember that right off the top. I can look and see.

But the idea is, we need the flexibility and we'll use the results. And, you know, the concept is totally changed from when they brought that in, Phase One, Phase Two, you know, 23 injection wells, and we just don't think that's the correct approach.

Q. Okay. Now, with regards to the EOR part of this case --

A. Yes, sir.

Q. -- EOR certification, did you say something about splitting the unit in half?

A. Yes, sir, if you notice, that --

Q. Where is that, that you're looking at?

MR. CARR: It's Exhibit A to Exhibit 8.

EXAMINER CATANACH: Exhibit A to Exhibit 8, thank you.

MR. CARR: Lots of help over here.

Q. (By Examiner Catanach) Okay, so what you guys are proposing is that at least the west half of the unit be certified now.

A. Yes, sir.

Q. All right. Now, you understand how the process works on the EOR tax credit, in that --

A. Probably not as well as I could.

Q. -- you will be required to demonstrate a positive production response.

A. Within five years.

Q. Yeah. Now, tell me how you're going to distinguish that, Mr. Cotner?

A. Well, I really hope that I bring you a curve that looks like Exhibit D. You know, today we're producing at 109 barrels of oil. So I guess, you know, there's good news and bad news in that, as I understand, because -- I'm not a hundred percent in agreement with the way that the EOR deal was handled, but I understand it was done that way for administrative reasons. The idea is that you don't want people to get a tax credit that's undeserved, and I understand that.

The good news is that 109 barrels a day of uneconomic production, there's not a whole lot of tax being paid. So to the extent I don't have any response, it's going to be a moot point. But we expect to see the response as shown on Exhibit 8.

And you know, the ideas -- I don't know that I can come in here and tell you which barrels are from the downspacing and which barrels are from pressure maintenance. You know, I could tell you something, but I could get ten people that would have ten different opinions on that. And the response is what we're after and the oil production is what we're after. It's not so much being able to quantify which element of that is attributable to pressure maintenance and which element of that is -- to modern completion techniques. And you know, there's just a lot of factors in this. It's going to be somewhat subjective.

But you will see the response. And if there's not one, then...

Q. Well, I just want to make sure that we don't see

-- a year from now, I don't want to see -- you know, I don't know if you had planned on coming in and saying, we've got a response, and you show me a curve that basically shows the response being a result of the infill drilling. I didn't know that you would understand -- I mean, I just wanted to clarify that, that we've had this argument with other companies too.

And I just don't know how you -- again, it's a problem. I don't know you separate that out.

A. I don't see the reason to separate it out, personally, in a project like this.

Q. Well, you can make your case when you come in next time.

A. Hopefully we'll have a big bump, to argue about how we split it.

Q. Mr. Cotner, have any of the other interest owners expressed any -- have you talked to them or -- I mean, is there any concern about what you're proposing here today, from any of the interest owners?

A. Well, I represent 96 percent of them today. I had plans to make offers to the remaining four percent, to buy their interest. You know, those people, you know, have such small interests that I guess it doesn't justify their time. There's several of them that are in arrears to the operator. So you know, like if I take over, I may foreclose on their interests if they're unwilling to sell, they're not paying their bills.

Again, I represent 96 percent of the unit. You know, that's an incredible amount, in my mind, of control and representation.

Q. Is there any problem, as far as you know, with the BLM or the State Land Office signing off on something like this, or have you talked to them at all or --

A. I've talked to them, and I've filed for the royalty reduction act and had good conversations with them. I think they, like the OCD, would really like to see something happen with this property. They're a little bit frustrated. Nobody's more frustrated than I am. I have invested a lot of time and a lot of money, and I'm sitting here today, hoping that I can go forward and that it hasn't all been for nought.

EXAMINER CATANACH: Okay, I think that's all I have.

Mr. Brooks, do you have anything?

MR. BROOKS: No, I don't think so.

MR. CARR: Mr. Catanach, during your examination of Mr. Hall you requested certain information, the number of injection wells in each of the projects that he was discussing, curves showing production from these various projects. He has checked, he has them with him. We have one copy of each. And the question is, would you like to see them today and question him about them, or would you like to have copies made and we'll submit those to you by the first of the week?

EXAMINER CATANACH: I think in the interest of saving some time, I think if you could just submit copies of those to me --

MR. CARR: We'll be happy to.

EXAMINER CATANACH: -- at a later time.

I would also, Mr. Carr, ask that you take a shot at drafting a plan of operation for this unit.

MR. CARR: A plan of operation.

EXAMINER CATANACH: A draft order, so to speak, summarizing --

MR. CARR: Would you like a draft order?

EXAMINER CATANACH: Yes, I would like a draft order.

MR. CARR: I didn't know what you were asking. I thought maybe I could plan the operation instead of Mr. Cotner. Yes, sir.

EXAMINER CATANACH: It might not be the first time.

MR. CARR: Not for Mr. Cotner.

MR. COTNER: It would be the first time for me.

MR. CARR: It would be.

EXAMINER CATANACH: Okay, is there anything further, Mr. Carr?

MR. CARR: Mr. Catanach, that concludes our presentation in this case.

EXAMINER CATANACH: Okay, there being nothing further, Case 12,112 will be taken under advisement.

(Thereupon, these proceedings were concluded at 3:29 p.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 12112 heard by me on March 7 2002.
David R. Catanach, 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 March 17th, 2002.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002