STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

CASE 10,771

EXAMINER HEARING

IN THE MATTER OF:

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

TRANSCRIPT OF PROCEEDINGS

ORIGINAL

BEFORE: DAVID R. CATANACH, EXAMINER

6 1993

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

July 15, 1993

A P P E A R A N C E S

FOR THE DIVISION:

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I N D E X

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E X H I B I T S

APPLICANT'S EXHIBITS:

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WHEREUPON, the following proceedings were had at 2:16 p.m.:

EXAMINER CATANACH: Call the hearing back to order, and call Case 10,771.

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

Appearances in this case?

MR. KELLAHIN: If the Examiner please, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the Applicant, and I have two witnesses to be sworn.

EXAMINER CATANACH: Additional appearances?

(Off the record)

(Thereupon, the witnesses were sworn.)

SCOTT E. GENGLER,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Please state your name and occupation.

A. My name is Scott E. Gengler, spelled

G-e-n-g-l-e-r, and I'm a petroleum engineer for OXY USA.

Q. On prior occasions, Mr. Gengler, have you testified as a petroleum engineer before the Division?

A. Yes, I have.

Q. Describe for us what it is that you've done on behalf of your company with regards to what is identified as the Skelly Penrose "B" Unit Waterflood Project. How are you involved in that?

A. I was involved in doing the studies to determine the feasibility of doing a 40-acre fivespot waterflood which would use improved oil recovery techniques to waterflood the Penrose formation, which is part of the Queen field, to better contact additional reservoir and increase sweep efficiency.

Q. Have you satisfied yourself that you have studied sufficient data, both geologic and engineering information, from which to reach conclusions about the eligibility of this project for entitlement for the New Mexico Enhanced Oil Recovery Act tax rate?

A. Yes, I have.

Q. In addition, have you participated on behalf of your company with regards to the compilation and review of data in compliance with the Division's underground injection control rules and the filing of the Division Form C-108?

A. Yes, I have.

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

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Mr. Gengler, let me show you what is marked as Exhibit Number 1 and, to commence discussion, have you indicate for us the outline of the unit and then identify for us what we're going to call the project area.

And when I use the word "project area", I want to be in agreement with you that I am describing by that phrase the area that you intend to use as the expansion or expanded use that will qualify under the definition for the severance tax reduction for an EOR project.

So when I say "the project area" that's what I'm asking you about, all right?

A. Okay.

Q. First of all, describe for us the unit.

A. The unit is indicated here on this map in the bold dark line. It's located six miles south of Eunice. It contains more or less 2600 acres.

There are currently 67 wellbores that are still active. Some are temporarily abandoned, and some are currently producing or injecting.

Q. When we find the project area as I've defined that term for you, how is that identified on the display?

A. The project area is identified in the shaded area. It contains approximately 760 acres.

Q. I'd like you to give us a historic background on the Skelly Penrose "B" Unit, starting off with the geologic and engineering concepts that were being utilized by the original operator when they sought to institute waterflooding for this project.

A. The Skelly Penrose "B" Unit was unitized in 1965 with waterflood operations beginning in 1966. Peak production was seen in 1971 of approximately 500 barrels a day.

Back in the early Sixties when this waterflood was put back together, the thought process behind the waterflood was that we had a very homogeneous reservoir that was multi-layered, had several sands, but were correlatable across the entire unit.

Most of the logs, though, that were available for this unit were of old vintage, so there wasn't a very good way of determining porosity and permeability, and there was no core data.

So back in the late Sixties and even during the Seventies, the thought process was, we had a very homogeneous reservoir that was adequately flooded on 80-acre spacing. The old adage of one primary reservoir barrel equaling one secondary reservoir barrel was used, and that was approximately what this unit was predicted to do, and they were satisfied at the time that this was an adequate waterflood covering the entire acreage.

The waterflood continued and started into depletion. By the mid-Eighties the economics of the unit were very poor, makeup water was ceased, and presently we're on a rapid depletion system.

In 1988, six infill wells were drilled to determine the existence of a mobile oil saturation within the unit. And after those six wells were drilled, the previous operator to OXY decided not to do any more work, mainly due to funding.

Q. The Application refers to the ultimate primary oil recovery from the unit as being 1775 million barrels of oil; is that about right?

A. Could you repeat that?

Q. Yes, sir. In the Application we were citing the recovery on a primary basis out of the unit.

A. That is correct.

Q. Is that the correct number?

A. Yes, it is.

Q. Okay. The period of time in which this project area was under primary oil recovery was approximately how long?

A. The first well that was drilled in this field, or on this unit, was in 1933.

Q. Approximately when was the unit created and initial waterflood operations commenced?

A. The unit was formed in 1965 with waterflood operations commencing in 1966.

Q. Have you satisfied yourself as an engineer that there is no remaining future potential for primary oil recovery within the unit?

A. Yes, I have.

Q. The period of time in which the unit was operated under secondary waterflood operation was under an 80-acre unit concept?

A. Yes, 80-acre fivespot.

Q. Describe for me what that means when you say that.

A. Your well spacing, including injectors, are spaced every 40 acres, and you have around each producing well four injectors spaced at 40-acre spacing.

Q. And the unit as you now find it still exists in that configuration?

A. Yes, it does.

Q. When we look at Exhibit 1, help us understand and see how it has been developed on an 80-acre fivespot development pattern.

A. As you can see, the original wells within the unit were drilled every 40 acres, and alternating wells were then converted to injection to form conventional fivespot waterflood patterns.

Q. Describe for me what was undertaken to determine whether or not OXY or anyone else could make a significant change, either in process or technology, or some expansion of the geologic area within the unit, so that you could now recover secondary oil that you might not otherwise get.

A. The previous operator commissioned an independent reservoir engineer to do a study for him. They believe that the improved oil recovery techniques used in some of the other formations in the Permian Basin, such as the San Andres and the Clear Fork, could be utilized in the Queen.

Q. These are all secondary recovery techniques, are they not?

A. Yes, they are.

Q. Okay.

A. These improved oil recovery techniques basically were on the premise that the entire reservoir was not being swept efficiently because of a heterogeneous reservoir, and by going to tighter spacing -- in other words, from an 80-acre fivespot to a 40-acre fivespot -- more area could be swept within the reservoir, and the portions of the reservoir that were not being swept or contacted by the 80-acre fivespot waterflood would be able to be contacted or swept by the 40-acre fivespot.

Because of this technology, this was being used in the San Andres and the Clear Fork, they did a study initially on the west Dollarhide Queen Sand Unit, which they operated.

They took this study and commenced infill drilling and conversion of wells to go from an 80-acre fivespot to a 40-acre fivespot.

What they found was that there was a bunch of high mobile oil saturation sitting in the reservoir that was not swept.

They began drilling in May of 1987 and conversion about the same time, and by early 1988 production had risen from 40 barrels a day to 1500 barrels a day.

They then commissioned the same independent reservoir engineer to do additional studies to see how this could be correlated to other units in the Queen that they operated, one being the Skelly Penrose "B".

And from this request a study was done by T. Scott Hickman, an independent reservoir engineer out of Midland, and a copy of this is attached in one of our exhibits.

Q. When we look at the unit as you find it now, you're on 80-acre fivespot patterns with how many current active producers?

A. Twenty.

Q. And how many active injectors do you have?

A. Seven.

Q. And what is your current producing oil rate on a daily basis?

A. 80 barrels a day.

Q. And how much water are you producing?

A. We are producing 945 barrels a day.

Q. If you continue in that current plan of operation under the 80-acre fivespot pattern, how much additional oil can be recovered without a significant change, either in technology or process?

A. In the project area or in the unit?

Q. In either.

A. According to projections from decline curve analysis, the unit would have approximately 75,000 barrels of recoverable oil left, and there would be about 8000 barrels left in the project area.

Q. What proposed changes and technology or process do you anticipate in order to be more effective in your sweep efficiency and to expand or extend the geologic area being swept by the secondary oil recovery process?

A. Well, the basis of our believing that this would be an improved recovery due to new technology and contacting new reservoir is that in the study done by Mr. Hickman, he did a comparison between the West Dollarhide Queen Sand Unit and the Penrose "A" Unit, which is located just to the east. It shares a common boundary with the Penrose "B" unit.

In this study he had modern logs and cores from the West Dollarhide Unit, and the reason that he chose the Penrose "A" is that he had a couple of modern logs that he used to correlate back to the Dollarhide Queen Unit.

In this correlation he found that the Penrose "A" was an analogous field to the West Dollarhide, and in correlating the old logs back to the new logs of the Penrose "A", this was found that the Penrose was contiguous across both the Penrose "A" and Penrose "B".

So we feel like we have an analogous reservoir that we had at the West Dollarhide Queen Unit. And based on this, from what we found at West Dollarhide Queen and from the Penrose "A" study, it was obvious to us that even though the sands are present across the entire unit, there is great variations of porosity and permeability, to the point where some of these sands were totally nonproducible because they were so tight.

This, along with the inefficiencies of the 80-acre fivespot, led us to believe that the 80-acre fivespot was not totally sweeping the reservoir as we had originally thought back in the Sixties, and by going to a 40-acre fivespot we could increase the vertical and areal sweep efficiencies in the reservoir to contact additional reservoir that would be unswept if the 40-acre fivespot was not undertaken.

Q. Let's look at Exhibit 1. There is an area shaded within the unit, with the yellow shading. What does that represent?

A. That is the project area.

Q. How did you as a reservoir engineer decide what the project area was going to be?

A. We took a look at the structure maps and isopach maps that were included within the Hickman study, and it was our decision to put this in, in the best reservoir area of the unit.

This area showed the highest primary production and the best secondary response under 80-acre fivespot, so we felt by working on the best area of the reservoir would allow us to achieve the best results.

Q. Let's divide the next issue in two parts. I want to address the additional injectors, and then we'll talk about the additional producers.

A. Okay.

Q. When we're talking about a change in process that is going to expand or increase the geologic area that's being swept, how do you achieve that by the additional injection wells that you're proposing within the project area?

A. By closing the spacing on the injection wells, you take away some of the discontinuity in between the sands.

The tighter the spacing allows you to sweep better the reservoir, because it takes out part of the discontinuity of the different sands and therefore allows you to have better sweep efficiency across the reservoir.

Q. When we look at the producing wells, why will not the new producing well simply represent additional primary recovery?

A. The new producing wells won't represent additional primary recovery.

There is some built-up oil from the 80-acre fivespot that was swept off to the side and not pushed from the injectors to the producers.

But from the six wells that were drilled in 1988 and from an experience at the West Dollarhide Queen, we found that that small amount of banked-up oil would not be primary; it's more part of the 80-acre secondary.

But it depletes very quickly. It comes in very quick and is gone, because there's no pressure injection being done to keep the pressure in the reservoir up to help sweep the reservoir.

Therefore, without the injection on a 40-acre fivespot around it, these wells deplete very quickly, and the recoverable reserves are very small.

The bulk of the reserves that we feel like will be recovered will be coming from the injection into the four wells around the producers.

Q. When we look at the oil producers within the project area, how will we know when those oil producers are demonstrating a positive production response in direct relationship to the change in technology or process with the conversion of producers to injectors?

A. We feel like that the -- after the well is drilled, we'll get a -- should get a fairly high kick, initial production, that will drop off very quickly.

As injection goes into the injectors around these producers, we should then see a secondary kick as in any secondary waterflood operation.

Q. Is the opportunity to have a reduced severance tax under the EOR credit an incentive to you and your company to initiate this project?

A. Yes, it would be an incentive, because it would help the economics. The investment that is required to convert the unit from an 80-acre fivespot to a 40-acre fivespot is quite large, and it would be an incentive for us to go ahead and start this project.

Q. That tax credit affords OXY the opportunity to select projects that would qualify for the credit and place them higher on your priority list, over and above other projects on which you might spend your resources?

A. Yes, that's correct.

Q. Let's look at the topic of the C-108 for a minute.

Attached to the end of the exhibit package -- it appears as OXY Exhibit 11 -- is a copy of Administrative Order WFX-643. Do you have a copy of that?

A. Yes, I do.

Q. You testified earlier in qualifying your credentials as an expert that you were personally involved in the preparation of the C-108 that was filed with the Division and led to the Administrative Order that approved the conversion of these wells for injection?

A. That's correct.

Q. As part of that process, did you find any wells that are called problem wells under Division definition within the area of review for any of the injection wells?

A. No, I did not.

Q. Describe for us the length of effort and the expenditure of resources that OXY has made in its commitment to upgrade this entire unit in order to make it an effective waterflood project again.

A. We purchased and became operator of this unit in February of 1993. We went out and made an assessment of the unit and checked all our injection wells, ran mechanical integrity tests on every well, found that numerous wells had failed.

We decided at that point in time that we would work on every well and bring every well within compliance under Commission rules and regulations.

To date, we have spent approximately $1.9 to $2 million cleaning this lease up and getting back into shape where it could be used as a waterflood project.

Q. Have you satisfied yourself that each and every one of the injection wells, not only within the project area but within the unit itself, will now pass wellbore integrity tests?

A. We have run mechanical integrity tests on every well now after they have been repaired and have filed every injection well within the unit, mechanical integrity tests, with the Hobbs office, and all of them have passed.

Q. Describe for us the financial commitment your company is making for this project. What is the estimated cost of this work?

A. Our company has budgeted approximately $2 million to install the 40-acre fivespot pattern.

Q. Have you commenced doing any of the work on the wells at this point?

A. Part of the project has been commenced. It is the part -- The costs are shown in Exhibit Number 9 in the back.

Q. Uh-huh.

A. We had to reactivate nine injectors and reactivate three producers in our process of fixing the injection wells that had failed the mechanical integrity test.

We felt that it was prudent while we were on the well and had a unit rigged up that we would go ahead and run our injection tubing and reactivate those injection wells that were already currently --

Q. Those were old injection wells, and not part of the expansion project?

A. That is correct, they were part of the 80-acre fivespot waterflood pattern.

And then we have reactivated the three producers that the previous operator had left temporarily abandoned.

Q. Other than that, you have not undertaken to spend the money or undertaken to do the work within the project area for the new injection wells or the conversion of producers to injection?

A. That is correct.

Q. And you haven't drilled the new producing wells?

A. No.

Q. Do you have engineering estimates of the additional production that would be attributable to the project area if the Division approves this as an EOR project?

A. Yes, I do.

Q. And what is that number?

A. We estimate that in the project area that there will be 971,780 stock tank barrels of water that could be recovered under a 40-acre fivespot waterflood.

Q. What's the engineering method used to reach that number?

A. We used a volumetrics technique.

Q. Have you made yourself familiar with the Division rules and regulations with regards to enhanced oil recovery projects that's set forth in Division Order R-9708?

A. Yes, I have.

Q. Let's start, then, with Exhibit Number 2, and have you identify and describe that exhibit.

A. Exhibit Number 2 is a production decline curve of the Skelly Penrose "B" Unit. In green is the oil production, in blue is the water production, in red is gas production, and the purple is water injection.

Q. The remaining secondary oil to be recovered by the continuation of this project is 8000 barrels of oil?

A. In the project area.

Q. Yes, sir. All right. Let's turn now to Exhibit 3. Identify and describe that display.

A. Exhibit Number 3 shows the ultimate primary production that is attributed to the unit. This is based on decline curve analysis and is estimated at 1.775 million barrels of oil.

It also indicates that the ultimate secondary production under 80-acre fivespot waterflood is 1.742 million barrels of oil, for a total ultimate production under current operations of 3.517 million barrels of oil.

The total oil produced as of April 1st of 1993 is 3.442 million, leaving the remaining production under current conditions for the unit of 75,000 barrels of oil.

Currently the unit is making 80 barrels of oil and 945 barrels of water with 20 active producers and seven active injectors.

Q. All right. Let's turn now to Exhibit 4 and have you talk about the reserve estimates.

A. In this exhibit, it shows our calculation for determining how many additional barrels of oil could be recovered under a 40-acre fivespot waterflood area.

Using volumetrics, we calculated in the project area a little over 9 million barrels of -- stock tank barrels -- original oil in place.

The project area cumulative production to date is approximately 1.4 million barrels of oil, which is a recovery of 15.2 percent.

That leaves approximately 7.8 million barrels of oil left in the project area at a current oil saturation of 39 percent.

Using volumetrics and a cutoff of a residual oil saturation of 30 percent, that leaves approximately 1.5 million barrels of oil recoverable in the reservoir.

Using a sweep efficiency of 65 percent under a 40-acre fivespot pattern, that would leave 972,000 barrels of oil recovered.

Q. The net pay upon which your reservoir estimate is made, is this the Penrose member of the Queen formation of the pool?

A. Yes, it is.

Q. That's our targeted fluid zone for this enhanced project?

A. Yes, it is.

Q. Okay. Let's go now to Exhibit 5. Would you identify and describe that?

A. Exhibit Number 5 is the reservoir study by T. Scott Hickman and Associates, who are an independent reservoir engineering consulting firm.

This study was done for the previous operator in 1987 as a feasibility of doing a 40-acre fivespot waterflood.

Q. Have you as a reservoir engineer reviewed and studied the information, the data and the conclusions reached by T. Scott Hickman?

A. Yes, I have.

Q. And how do your conclusions and opinions compare to theirs?

A. They correspond pretty closely.

Q. So that the Examiner has the benefit of understanding what you consider to be the essential elements of this report, highlight for us those portions of the report that are significant.

A. The significant parts in the T. Scott Hickman report, if you turn to page 6 of his report, his discussion, he has under there Conclusions.

Number 3, it says, "Under current mode of operations, the Penrose 'B' Unit is in the latter stages of depletion", which corresponds to the 75,000 barrels of remaining reserves to be recovered out of the unit.

And Number 6, "Oil recovery has varied greatly across the field due to variations in completion techniques, reservoir heterogeneity and water injection inefficiencies."

This corresponds to our thought process on the unit where there is a lot of discontinuity between the sand members due to porosity and permeability changes, and therefore we saw various different recoveries from secondary operations on the unit.

On the next page, under Geology and Reservoir Properties, Mr. Hickman states that, "No quantitative well logs or cores were available with which to determine lithology" within the Penrose "B" Unit.

He also states that "Porosity and permeability are apparently highly variable as demonstrated by individual well performance and simulation studies."

In the third paragraph he says, "A modern log suite was available from the Penrose 'A' Unit Number 66, which was used to approximate porosities and original water saturations for the Penrose Sand in this area", which includes both the Penrose "A" and Penrose "B" Units.

"The log analysis indicated that the 'A' Unit Penrose sand formation was similar in stratigraphic and lithological character to that of the West Dollarhide Queen Sand Unit", which is our analogous situation for this unit.

He goes through some of the methodology that he went through to determine the reserves. His project area that he chose for the unit uses the same area that we have, only it's a little more expanded than what OXY proposes to do.

He came up with 1.2 million barrels of recoverable reserves, which is closely in line with the 971,000 barrels of oil that we feel like we can get in our project area.

Q. Have you reviewed the geologic displays and interpretations made concerning the geology?

A. Yes, I have.

Q. Are they consistent with your understanding and interpretation of the geology?

A. Yes, they are.

Q. Recommendations made by the Hickman report on page 7 are at the top of the page. Are those consistent with your recommendations?

A. They're fairly close. We will probably approach them a little bit different method in that we changed the project area, or the initial phase of the project area, but after that we plan to go about the same methodology as he was going to do, do phase one, gather data, and do logs and cores and use that to apply to other parts of the Unit to further develop this Unit.

Q. Let's turn now to Exhibit 6. Would you identify and describe that?

A. Exhibit Number 6 is a Society of Petroleum Engineers paper written by Mr. Hickman and C.D. Hunter of T. Scott Hickman and Associates. It is a paper about the redevelopment of completed Queen waterflood projects in the Permian Basin.

It is based on reports like the Penrose "B" that he did, not only on the Penrose "B" but on four or five other different units without southeast New Mexico and Andrews County, Texas.

Q. What's the conclusion of the paper?

A. The conclusion of the paper is that based on improved oil recovery techniques utilized in the Clear Fork and San Andres Formations where there is a lot of reservoir heterogeneities and disconformities, that this process could be used on the Queen formation.

They state that they've analyzed over a dozen of the depleted Queen waterfloods and have determined that the improved oil recovery potential of these waterfloods is significant.

Q. You've said earlier that you've studied the Division rules and regulations on qualifying for the Enhanced Oil Recovery project. Let me ask you some specifics.

When we look at the additional producers, why don't those producers represent simply infill wells that are recovering additional primary oil?

A. Based on the six wells that were drilled at the Penrose "B", like I said, we got a good initial response.

But if you look at a decline curve, which is attached here, of the six infill wells drilled on the Penrose, they dropped off very quickly. And the reasoning behind that is that there was no pressure backup for these wells.

Q. Let's look at that. It's Exhibit 7?

A. Yes, it is.

Q. Okay.

A. In Exhibit 7 it shows the six wells that were drilled in 1988 in a 40-acre producer location. As you can see, they came in fairly good. They'd come in in the range of 30, 40 barrels a day, but were dropping off quickly. And as soon as they drilled another well it would bring production back up and then it would drop.

And once they got done drilling the six wells, production quickly dropped on all six wells down in the range of 20, 25 barrels a day for all six wells.

This is really a good indication of, you know, high mobile oil saturation that was down there, but without the pressure backup of the injection wells surrounding these, additional oil would not be recovered out of these wells, and the production would be insignificant.

Q. How do these -- the performance of these specific infill wells compare to what Hickman had projected would occur under his study?

A. These wells are probably not quite as good as what Hickman had projected, and I believe that the reasoning behind this was that the pressure maintenance of the reservoir prior to the drilling of the wells in 1988 was not there.

They had stopped putting makeup water in the formation, and because of that, our reservoir pressure was low, not allowing us to get much sweep efficiency through there.

Q. Apart from the slight difference in productivity, though, it does validate the Hickman conclusions in his study?

A. Yes, it does, that there are permeability and porosity variations, that there are some disconformities found within the reservoir, which would make sweep efficiency very low under an 80-acre fivespot pattern.

Q. Another issue is whether or not this represents a significant change in either process or technology, or an increase in geologic area, rather than a continuation of the existing project.

Is this a logical continuation of an existing project or, in your opinion, does it constitute the application of a significant change in process or technology?

A. I believe it's not a continuation of an existing project. The fact that we're changing our process by reducing our spacing due to changes in technology that has allowed us to do reservoir characterization and other models that would tend to make us believe that the reservoir isn't continuous as what we had thought back in the Sixties, so by changing the spacing I believe that we are changing our technology, improving our methodology, because we're now sweeping more area within the current reservoir that would not be swept by the 80-acre fivespot.

Q. Does this constitute an increase in the size of the geologic area, then, that is subject to effective sweep efficiency?

A. Yes, it does.

Q. Let's turn now to Exhibit 8. Identify and describe that display.

A. Exhibit Number 8 is a decline curve analysis of the project area.

As can been seen in the decline curve analysis, in 1984 makeup water was cut off because of economics. The operator at that particular point in time was not making any money from the unit, and the decision was made to cut the makeup water.

About six to nine months later, production started declining.

They sold the unit and the new operator drilled the six wells, which would be five within this project area, and you can see the immediate response in 1988 to the drilling of these wells.

Production then quickly dropped back off. They had a couple wells go down in late 1989, they reactivated them in 1991, and due to economics had to shut a couple more down in 1992.

Based on the dropoff of decline, we feel like that there's only approximately 8000 barrels to be recovered out of the project area economically, and that's the number that we came up for a couple of reserves for the project area.

Q. Let's turn now to Exhibit 9. Would you identify and describe that?

A. Exhibit 9 is the cost estimates to put in a 40-acre fivespot waterflood project in the project area.

Q. Okay, and then Exhibit 10?

A. Exhibit Number 10 is a decline curve of the project area. In green, the oil production. And the red line is the projection of oil production under a 40-acre fivespot pattern.

Q. Did you sign the verification under oath that's attached to the Application in this case?

A. Yes, I did.

Q. And attached as an exhibit to the Application is a list identifying the producing wells and the injection wells by name and location?

A. Yes.

Q. Did you also participate in editing the proposed draft order for submittal to the Examiner today?

A. Yes, I did.

Q. One of the things that you have to obtain if the Division approves the project is to establish a baseline, if you will, by which then the Division and others might judge whether or not you had a positive production response. Are you with me?

A. Yes.

Q. Okay. What information do we have that we have presented that might be utilized by the Division, you or anyone else, that would establish the existing baseline of production, so that we can measure if the enhanced activity in the project area is showing a positive production response?

A. In Exhibit Number 8, which was the decline curve analysis of the remaining oil found in the project area, we found that there's 8000 barrels that we could economically recover from the project area.

That should be our baseline for this particular project.

To determine if we're successful, we would compare it back to this 8000 barrels.

Q. And is that what you would use on behalf of the operator to file for certification of your project when it has demonstrated a positive production response?

A. Yes.

Q. Do you have an engineering opinion as to whether or not this project area qualifies under the New Mexico Act for the Enhanced Oil Recovery --

A. Yes, I do.

Q. -- Tax Credit? And what is that opinion?

A. I believe that it does qualify under the rules and regulations.

MR. KELLAHIN: That concludes my examination of Mr. Gengler.

We move the introduction of his Exhibits 1 through 11.

EXAMINER CATANACH: Exhibits 1 through 11 will be admitted as evidence.

MR. KELLAHIN: I didn't ask Mr. Gengler to go through the draft order, but he is familiar with it and assisted me in drafting it, and we believe that he and I together with Mr. Foppiano have put in appropriate findings that comply with the intent and purposes of the rules and regulations.

In addition, while I propose not to call him, Mr. Foppiano has been actively involved in the project. He does have a perspective that you might want him to share with you, insofar as he has done almost a dozen, I believe, of these projects in Texas, where there is some similarity in the rules.

While that's certainly no indication about how you should do it, he can share with you the experience in Texas about how they handle similar kinds of things, if that's of interest to you.

So while I don't propose to call him as an expert to talk about it, we invited him here to share with you answers to the questions that you may have.

That concludes our presentation.

MR. STOVALL: Is this the state where they've authorized secondary recovery for water fracs?

MR. KELLAHIN: You'll have to ask him.

(Off the record)

MR. STOVALL: I'm sorry, sand frac?

MR. FOPPIANO: No, I don't think --

(Off the record)

MR. STOVALL: Mr. Kellahin, could we have a few minutes --

MR. KELLAHIN: Sure.

MR. STOVALL: -- you and I?

(Thereupon, a recess was taken at 3:08 p.m.)

(The following proceedings had at 3:20 p.m.)

EXAMINER CATANACH: Okay, let's go back on the record.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Gengler, run through it with me, and within your project area I want to just kind of go over a little bit.

Which wells are infill drilled in 1988? Is that the right date?

A. Yes, that's correct. There were six wells drilled in 1988, five of which are in the project area. These wells are wells 64 through 69.

64 is located in the fivespot with 26, 27, 34 and 33.

65 is located in the fivespot with 17, 18, 29 and 30.

66 is in the fivespot just south of 64.

67 is in the fivespot with -- surrounded by 28, 29, 31 and 32.

68 is just south of number 67.

And 69 is located north of the project area. It's surrounded by wells, 7, 8, 15 and 16. That's located in Section 32.

Q. The wells shown by a blue triangle on your Exhibit Number 1 are wells that were previously approved for injection?

A. Yes.

Q. By the original order, or --

A. No, those are the ones that we have filed our C-108 to convert to injection, which was filed in May of 1993.

The wells that are located with the black triangle pointing up are the wells that are current injectors approved under the original Order back in 1965 or 1966; I can't remember the exact year.

Q. Okay. The new conversions, I've got Number 18, 26, 28, 30, 33, 31, 37, 39, 44.

A. That's correct.

Q. Nine wells.

A. That's correct.

Q. Now, the ones you said in black are the ones previously approved for injection?

A. That is correct.

Q. Those wells will remain injection wells?

A. That is correct.

Q. Okay. The red circles are proposed infill wells, producing wells?

A. That is correct.

Q. And there are five of those that are going to be drilled?

A. That is correct.

MR. STOVALL: 70, 71, 72, 73 and 74.

EXAMINER CATANACH: Thank you, Bob.

Q. (By Examiner Catanach) Exhibit Number 7, which concerns the decline curve of the six infill wells drilled in 1988, do you have any numbers on what those wells have recovered to date?

A. The best well as of the first of the year had recovered approximately 13,000 barrels, and the worst well had recovered 4000 barrels.

Q. And the worst, 3000 did you say?

A. 4000.

Q. 4000. How do those recoveries compare with the original oil recoveries for some of the wells in the field?

A. As far as secondary or primary?

Q. As far as primary.

A. If you look in the Hickman report, he has a map which gives not only ultimate primary reserves for each well -- it's -- Let me find the exact page.

Page 14. If you look on that particular page -- I'll wait for you to get there. The number above the line is the ultimate primary production calculated by decline curve analysis on individual wells, and the number below the line is the ultimate secondary, again by decline curve analysis.

Primary numbers, the original well in the field, which is well number 34, had 147,000 barrels of primary oil.

As typical Queen production in the area, you know, the first well usually has the highest cum primary, and then as each well is successfully drilled thereafter, there's lower reservoir pressure and they recover an incremental less amount of oil than the one before it.

But I would say an average number for a Queen primary oil producer in this area would be about 25,000 barrels of oil.

Q. Have you projected on your five infill wells, have you projected what those may ultimately recover under primary, just primary?

A. Are you calling primary the initial kick?

Q. You're still -- Within the project area you're currently injecting; is that correct?

A. Since February of 1993 we have reactivated -- The previous operator was down to one injection well prior to us taking over, and we have now reactivated seven injection wells.

I guess in answer to your question, if you were calling, we drilled the wells, the initial production that we got from that as primary oil production, our projections would be very similar to the five wells drilled in 1988, probably in the range of 15,000 to 20,000 barrels at the most.

Q. Total?

A. Total oil production, if no injection was put in the ground around them.

The six previous wells are pretty much in that situation. They have not had any water injection support. And without that water injection support, the reserves that have been produced so far is pretty much what those wells will -- will be an indication of what they'll produce ultimately.

Q. Drilling the infill wells is not like -- it's not at all like going into a virgin reservoir. You've lost a lot of pressure from primary depletion already; is that your opinion?

A. Yes, we've lost pressure from the primary depletion.

And then when they quit injecting makeup water in the 80-acre fivespot, there was no additional water being put in the ground. So as the oil and gas and water was taken out, the water was disposed of, thus creating a pressure decrease in the reservoir.

Q. Let's see if I understand correct.

Under current conditions you expect that you would recover 8000 additional barrels, if nothing changed?

A. In the project area.

Q. In the project area.

A. That is correct.

Q. And with the process change, you're going to -- you're projecting how much?

A. We're projecting 971,780 stock tank barrels.

Q. Has any of the work on converting the wells to injection been commenced yet?

A. No, all the wells that are planned to be converted to injection are currently producing, with the exception of one which we temporarily abandoned, within the last two or three weeks, and all we did was set a cast iron bridge plug and took the equipment to another well within the unit.

Q. You mentioned something about the previous operator only had one well injecting when you took over?

A. That is correct.

Q. Do you know how long that status was, what -- that he had been doing that?

A. He had -- Basically he had a lot of injection line leaks, and he would kind of rotate around which wells he would put water in, based on leaks, not only in the tubing, but in injection lines, and that probably had been going on for several years.

The previous operator had a funding problem and wasn't able to spend much money out on this unit. It was directed to other properties that he had operated, and the maintenance on this unit was very poor. That is why we had to spend close to a million dollars to get the unit back into workable shape.

EXAMINATION

BY MR. STOVALL:

Q. What kind of condition is the unit in now, the equipment and all that? I mean, have you done a lot of that?

A. We've spent $2 million. We have worked on every injection well within the unit and have run mechanical integrity tests after repairs on every injection well.

We have probably been on 80 percent of all the producers now and did a mechanical integrity test on the producers to verify that the casing was in good shape and plan to finish within the next month the remaining producers to get everything in shape to be able to do all the work that we plan to do out there.

Q. What about production equipment? Have you done much work on that? Have you -- How much have you done there to just basically get those producing wells, particularly, back into producing condition where they're doing whatever they can?

A. We've replaced a lot of the tubing and rods within the producing wells. We've done a lot of patch work on the battery and injection station.

Part of our plan in this 40-acre project is to replace a majority of the production equipment in the battery end, in the injection station, because we feel like the long-term operating of that equipment would cause some problems.

Q. Another question. As often happens in fields, they kind of get ignored, as this one has been, and then when you go back to look at a project as this, you do some stuff that should have been done all along to existing wells. And as a result, you increase production. Right?

A. That is correct.

Q. Do you have at this point an idea of what the current production would be with the equipment in good shape from the field as it exists today?

A. Yes, I believe we've pretty much got the field into that condition now.

We have been on, like I said, 80 percent of the producers. The ones that are making enough oil to be economic have been reactivated. We have put in new producing equipment, both tubing and rods and pumping units, and I feel like 80 barrels a day is the peak production.

A little bit of that is flush, you know, it will probably level out a little bit lower than that for the unit. But I feel like that is a good number as what the unit, you know, could possibly do at this point in time.

Q. That would be the baseline for an incremental recovery determination, is what it would do if you take -- if it's in shape, not what it does if you've ignored it for several years?

A. Correct, but you're talking about in the project area. That was the first area that we went into to get everything going, and that has been pretty much going since March.

And we saw a slight increase on there, and it's indicated in Exhibit Number 8 where we made our decline curve analysis. You can see in early 1993 that jump.

MR. STOVALL: Maybe I can find my Exhibit 8.

(Off the record)

Q. (By Mr. Stovall) Yeah, I see what you're talking about.

A. The dark heavy line is the decline projection.

But if you see in the dashed line, it takes it from the current production of approximately 28 barrels a day for the project area.

Q. Right. Okay, so that --

A. So we are taking --

Q. So that, you feel, would be a real legitimate baseline production with proper attention being paid to the project area equipment, wells, et cetera?

A. Yes. We have gotten all that equipment, and in the project area in good shape, been producing for several months now, and we feel like that is a good number for it, based on this historical decline.

We then projected from that number the 8000 barrels of recoverable reserves.

MR. STOVALL: That's all I've got on that line of questioning.

EXAMINER CATANACH: Are you done?

MR. STOVALL: For the moment.

FURTHER EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Gengler, I don't know if you're familiar with -- We had a case somewhat similar to yours, heard back a few months ago, and --

MR. STOVALL: Mr. Kellahin is handing you the Order, I believe. Marathon; is that correct?

Q. (By Examiner Catanach) There is some analogy to your situation in that at least half of your infill wells were drilled some time ago, and converting the pattern to 40-acre fivespot seems to be a logical continuation of a process that may have been started several years ago.

Do you have an opinion on that?

A. Yes, I don't believe that it's a continuation of a process.

The previous operator drilled these wells to determine how much mobile oil saturation was in the reservoir. He did not get the big response that he got at West Dollarhide, so he pretty much abandoned it. He never injected water around these wells.

So in my opinion, it wasn't really an extension of a waterflood project. I mean, if you're not injecting water around these wells, you're not waterflooding that area of the reservoir.

So in my opinion, basically, he got some flush production that was built up from the 80-acre fivespot, and it was a very low amount. You were calling it primary production, but the significant process is putting the water in on a tighter spacing to contact areas within the reservoir that were not contacted, to get this 971,000 barrels of oil.

As can be seen by these six wells, we're not going to get anywhere near that kind of recovery from just the flush production.

So to me, the actual process is in the

conversion of the wells and going to an improved waterflood situation where we're using the technique of tighter spacing to get around reservoir heterogeneities and permeability and porosity variations, to get a greater sweep efficiency, both areally and vertical.

Q. Is this an economically viable project without the EOR tax incentive?

A. Yes, it would be an economical project. it would dampen the economic projections of it, and when you put the project up against the other possibilities that we have in our company to spend money on, it would definitely lower the ranking of the project -- or this particular project in the rest of them, as far as a project that needed to be attended to fairly quickly.

EXAMINER CATANACH: I don't have any more questions.

MR. STOVALL: I just have -- Let me just ask one.

FURTHER EXAMINATION

BY MR. STOVALL:

Q. Would it be fair to characterize the previous operator's treatment of the project as they had more or less abandoned it and your company has kind of restarted it?

A. I can only speak on --

Q. From an engineering standpoint, not from a regulatory standpoint. But just from an operational standpoint, have they just kind of -- and I don't mean abandoned in the sense of, you know, plugged well, walked away.

But it sounds like it didn't really get any priority.

A. I would say on an engineering standpoint, looking at it from a distance, I would agree with you.

Q. Okay.

A. From my understanding, I felt like they were looking for outside funding to try to do some of the same things we were but were unable to obtain that.

EXAMINER CATANACH: Anything further?

MR. STOVALL: Well, I think there's something.

Mr. Kellahin, did you want to go back into some areas here briefly?

MR. KELLAHIN: Only to clarify my intent, Mr. Stovall, Mr. Examiner.

The last comments by the Division and by the witness give me concern about the status of the project, and I would be more comfortable if the Division incorporated into its consideration of approving this as an EOR project also the appropriate findings within this Order to approve the expansion area under the typical C-108 approval process.

And what I am proposing is that Administrative Order WFX-643 may have in fact been issued in error and ought to be vacated, and to have the approvals accomplished by the Division, by incorporating them into this case and into the order issued for this case. I believe we complied with the procedures to let that take place.

The Application and the advertisement for hearing included the expansion of the project area. Mr. Gengler has already testified under oath that the C-108 he filed, to the best of his knowledge, complies for approval under that permitting process and that OXY has undertaken wellbore integrity tests of all their wells, and they will stand inspection.

Because I am not certain as a lawyer whether this Administrative Order properly approves the expansion of those wells, I would request that you withdraw and vacate the Administrative Order and that I submit to you an order in this case that will accomplish the approval of those wells within the context of this hearing.

That's all we have.

MR. STOVALL: And in fact, this is more --

Are you stating that on the basis that this is more than just an expansion to maintain pressure as defined in Rule -- I think it's 702, that this is really a change in process, that is -- changes the character of the project and therefore that Order was probably not comprehensive?

MR. KELLAHIN: Well, I think you've stated my concern as a layman.

I hear Mr. Gengler talk as an expert, and what I hear him saying to me is that his project was abandoned for all purposes by a prior operator.

It makes me uncomfortable to use an administrative order that may in fact have underpinnings on the original waterflood order, and I think it is a better process for us all to have Mr. Gengler's new technology, what I think is an effective and a substantial change, in the process for the accomplishment of a true objective set forth in a single order, and not to have incorporated by reference a prior order that may in fact not serve the purpose that we now intend it to.

EXAMINER CATANACH: There being nothing further in this case, Case 10,771 will be taken under advisement.

MR. KELLAHIN: There's an opportunity here, if you care to go through the draft order, we do submit it to you. It was our best effort to get the right findings in here.

If you give me a chance, I will submit to you perhaps tomorrow the edited draft order that now incorporates the C-108 language so that you will be looking at a proposed order that is comprehensive as to this topic.

EXAMINER CATANACH: Okay. Thank you, Mr. Kellahin.

Okay, this hearing is adjourned.

(Thereupon, these proceedings were concluded at 3:47 p.m.)

* * *

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation 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 July 23rd, 1993.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. _____,
heard by me on ______________ 19____.

____________________, Examiner
Oil Conservation Division