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 THE WISER OIL COMPANY FOR CERTIFICATION OF A POSITIVE PRODUCTION RESPONSE IN THE CAPROCK MALJAMAR UNIT AREA, LEA COUNTY, NEW MEXICO	CASE NOS. 12,147
APPLICATION OF THE WISER OIL COMPANY TO QUALIFY THE SKELLY UNIT AREA WATERFLOOD EXPANSION PROJECT FOR THE RECOVERED OIL TAX RATE, EDDY COUNTY, NEW MEXICO	12,148
APPLICATION OF THE WISER OIL COMPANY TO QUALIFY THE STATE "D" LEASE WATERFLOOD EXPANSION PROJECT FOR THE RECOVERED OIL TAX RATE, EDDY COUNTY, NEW MEXICO	12,149
APPLICATION OF THE WISER OIL COMPANY TO QUALIFY THE STATE "AZ" LEASE WATERFLOOD EXPANSION PROJECT FOR THE RECOVERED OIL TAX RATE, EDDY COUNTY, NEW MEXICO	and 12,150
	(Consolidated)

REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

ORIGINAL

March 18th, 1999
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 18th, 1999, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 18th, 1999
Examiner Hearing
CASE NOS. 12,147, 12,148, 12,149 and 12,150 (Consolidated)

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EXHIBITS

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APPEARANCES

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* * *

WHEREUPON, the following proceedings were had at 1:08 p.m.:

EXAMINER CATANACH: Okay, at this time we'll call Case 12,147.

MR. CARROLL: Application of the Wiser Oil Company for certification of a positive production response in the Caprock Maljamar Unit Area of Lea County, New Mexico.

EXAMINER CATANACH: Call for appearances in this case.

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe, representing the Applicant. I have one witness to be sworn.

Also at this time, I would like this case to be consolidated for hearing with the next three cases, 12,148, 12,149 and 12,150. Although they involve different areas, they do involve immediately adjacent areas, and the area being waterflooded is the same geologic interval. And so we have some common exhibits, and the testimony may be similar for each project. So I would ask that they all be consolidated for hearing.

EXAMINER CATANACH: Okay, at this time we'll call Cases 12,148, 12,149 and 12,150.

MR. CARROLL: Application of the Wiser Oil Company to qualify the Skelly Unit Area Waterflood

Expansion Project, the State "D" Lease Waterflood Expansion Project and the State "AZ" Lease Waterflood Expansion Project for the recovered oil tax rate, all in Eddy County, New Mexico.

EXAMINER CATANACH: Call for any additional appearances?

Okay, will the witness please stand to be sworn in?

(Thereupon, the witness was sworn.)

MATT EAGLESTON,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name for the record?
A. Matt Eagleston.
Q. And where do you reside?
A. I reside in Dallas, Texas.
Q. Who do you work for and in what capacity?
A. I'm a project manager for the Wiser Oil Company.
Q. By profession are you an engineer?
A. I'm an engineer.
Q. And have you previously testified before the Division?
A. I have not.

Q. Would you please outline for the Examiner your educational and employment background?

A. I received a bachelor of science degree in petroleum engineering from Texas Tech University in 1982. I've worked for several companies during the ensuing 16 years, I've been with Wiser for the last three, most of my career working in the Permian Basin on waterflood problems.

Q. And does your area of responsibility at Wiser include the Permian Basin of southeast New Mexico and southwest Texas?

A. Yes, it does.

Q. And are you familiar with engineering matters related to these four Applications?

A. Yes.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Eagleston as an expert petroleum engineer.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Bruce) Now, Mr. Eagleston, we're talking about basically two projects here; isn't that correct? The Caprock Maljamar Unit and then the adjacent Skelly area?

A. That is correct.

Q. Okay. First, we're going to go into the Caprock Maljamar Unit, or the CMU. Now, this area, if I'm correct, previously received the EOR qualification when the unit was expanded; is that correct?

A. When the unit was formed.

Q. When the unit was formed, excuse me.

A. That's right.

Q. And so today you are here on this particular unit seeking certification of a positive production response?

A. That is correct.

Q. Let's start with Exhibit 1. Would you identify that for the Examiner and tell him what it shows about this unit?

A. Okay, this is just a map of the unit, which identifies the phases that were developed when the unit was formed. When the unit was originally formed in May of 1994, the development proceeded on a three-phase formula and the certification for the EOR tax credit was granted in a phase format.

And it was -- The original Phase 1, which is in yellow, was certified at the time the unit was formed, May 1st of 1994. Phase 2 was certified November 8th of 1994. And Phase 3 was certified October 1st, 1997. This was as development proceeded and injection operations began in each area.

The larger purple circles represent wells, infill wells, that Wiser has drilled as part of a development program. The red dashes indicate the waterflood patterns that have been developed also in addition to that.

Q. Also on this map, were there any new or replacement injectors drilled by Wiser as part of this program?

A. Yes, there were several. The wells that are -- In order to make them more easily recognizable, we had our numbering scheme, starting them with the 260. So any wells that are 260, 261, 262 and so forth, were actually replacement injectors. These were replacements for older wells that had been plugged and abandoned or whose casing integrity was such that they couldn't be used as injectors.

Q. Let's move on to Exhibit 2. Could you identify that and give a little bit of history of this particular area, which is now in this unit?

A. Exhibit 2 -- Page 1 of Exhibit 2 is just a brief history of the Caprock Maljamar Unit area. The Maljamar field was discovered in 1926. The first well was drilled in what became eventually the Caprock Maljamar Unit in 1942. Over the next 20 years or so, development proceeded on 40-acre spacing. Production peaked in 1959 on primary operations.

Waterflooding, using 80-acre fivespot patterns, was started in the area in the early 1960s. This was prior to there being a unit. It was -- What is now the Caprock Maljamar Unit was actually under flood by five separate operators.

Waterflooding was successful and continued for many years, but it had effectively ceased by the late 1970s. Wiser stepped in in 1992 and 1993 and in several transactions acquired 100 percent of what is now the unit area and subsequently unitized that entire area in 1994, into the Caprock Maljamar Unit.

Production at the time that Wiser acquired the properties was only 290 barrels a day, from 39 active producers. There were 16 injection wells, but they were simply recycling produced water; it was a disposal project and not really an active waterflood at that time.

The facilities were in poor condition, and production was nearing the economic limit. There wasn't a lot of life left in the properties at that time.

Wiser bought the properties in anticipation of a major development program, which they started in 1993 and accelerated in late 1995, which included downspacing most of the unit to 20-acre spacing and restarting the waterflood, using 40-acre five-spot patterns. We had to basically rebuild all the facilities at that time as well, because they had deteriorated to the point of really not being usable.

Production peaked at a little over 1300 barrels a day following this program, and in November of 1998, the date that I prepared this exhibit, the last information we had, production averaged 868 barrels a day, from 68 active producers, and we were injecting approximately 12,500 barrels of water per day into 81 active injection wells. We used freshwater makeup from Conoco's system.

Q. Mr. Eagleston, before you move on to the second page of this a couple of things.

When Wiser took this project over, was it at or near its economic limit?

A. Right, yeah, it was pretty close to being done, basically.

Q. And so if an expansion had not taken place, a lot of these wells could conceivably have been plugged or plugged and abandoned?

A. Absolutely.

Q. The other thing you mentioned, you said you decreased spacing to 20 acres. Well spacing is still 40 acres out there; you were infill drilling?

A. That is correct.

Q. Okay. Why don't you move on to page 2 of this exhibit and tell the Examiner a little bit about it?

A. Right, this is just a page that gives some data broken down by phases, the number of producing wells, injection wells, the amount of injection, volume, that's going into each phase, and also when each phase began, as far as injection is concerned.

I'd like to point out at this time that we did spend a substantial amount of capital on the injection part of the system, particularly here in the Caprock Maljamar Unit, because of the fact that the facilities had deteriorated to such a degree. In fact, the way we looked at the program was on a pattern-by-pattern basis. We had cost per pattern, recoveries per pattern, and so forth.

The cost per pattern, if you take the $35-plus-million, the cost per pattern at CMU was $586,000. Of that, it cost about $325,000 on average to drill the infill producing well, which means we spent approximately $261,000 per pattern to refurbish and initiate injection operations for that pattern. That would include the conversion or re-entry of old producing wells and converting them to injection.

In some cases we entered P-and-A'd wells. We re-entered eight wells that had previously been plugged, converted them to injection service, converted 50 existing producers to injection service, and of course had to completely rebuild the injection facilities. So, just to point out that it was a substantial amount of capital employed in the injection part of this project.

At the bottom of the page an item of note here, estimated net value. This is the incremental cash flow expected from the project. I used the year-end 1998 reserves in pricing that we just completed, and as you know, we have to use year-end prices, flat, in that SEC calculation, and therefore we were using $9.35 a barrel for that. That's the price we were receiving at the end of the year, and at that rate it's obviously not an economic project.

So what I did to make a fair representation of the project, I used a more normal -- what I would call a more normal price of $17 oil for the rest of the project, and that results in a $7 million incremental profit.

Q. Was the project economically feasible when it was first instituted?

A. Yes.

Q. And even right now, just on a month-to-month basis, is there a positive cash flow?

A. Oh, certainly, uh-huh.

Q. Otherwise, you couldn't keep --

A. We wouldn't continue, right.

Q. Mr. Eagleston, let's move on to Exhibit 3 next. What does that represent?

A. Exhibit 3 is simply a decline curve of the total unit area. If course, prior to 1994, this would be the combined production from several leases that eventually made up the unit. And it just shows that we were on a decline, a fairly modest decline, prior to the development project.

The red line shows the decline, how it would have continued. It probably would have cut off well before actually where it's shown to be going, 2001. The project probably would have been uneconomic before that time.

The green line shows production increasing substantially above where it would have been had we not done anything. The yellow line is our current forecast of production.

Q. Do you have a rough estimate -- I know it's not tabulated on this map -- of the amount of incremental reserves that this project will recover over what would have been recovered --

A. Right.

Q. -- if the project had not been expanded?

A. Right. We had estimated about 6 million barrels incremental recovery from this project.

Q. Okay.

A. It works out to approximately -- Once again, we talked in terms of patterns. It worked out to approximately 100,000 barrels per pattern, is what we anticipated being able to recover.

Q. Okay. And I notice that you -- really, at the time you commenced the project, you substantially increased the injection of water at that same time as you --

A. That is correct. Yeah, the injection work was contemporaneous with the drilling of the producing wells.

Q. Okay.

A. And so injection ramped up at the same time production did.

Q. What does the next batch of exhibits show, the exhibits marked as Number 4?

A. These exhibits -- there's three of them -- they are decline curves by phase. I didn't have the data broken down in a format to go back to 1980, so we started in 1993 with these curves, and they simply show the same information, broken down by phase.

Q. Have you seen, in your opinion, a positive production response from the unit?

A. Yeah, we're clearly well ahead of where we would have been, had the project not occurred in each phase.

Q. Looking at these maps, can you give an approximate date when...

A. Yeah, I think in Phase 1, and it's not marked on here, but I believe that -- and actually, you could choose an earlier date, but I believe that by October 1st of 1994 production had ramped up to a point where it was clearly and demonstrably above the trend line that was established previously.

Q. And that was for Phase 1?

A. That was for Phase 1.
Q. What about --
A. In Phase 2, I would choose a June 1st, 1995, date. Once again, you could choose an earlier date, but that's a date that I think is pretty clearly above the line.
And in Phase 3 we chose -- in this case, January 1st of 1998.
Q. You could again conceivably choose an earlier date; isn't that correct?
A. That is correct.
Q. But the EOR certification was not obtained for Phase 3 until what? In 1997?
A. October of 1997.
Q. Anything else on this exhibit, Mr. Eagleston?
A. Nothing.
Q. Okay. What does the two plots on Exhibit 5 show?
A. I just picked a couple of wells that are representative. Caprock Maljamar Unit 167 is on the east side of the unit. It's in Phase 1. Number 186 is on the west side of the unit. It happens to be in Phase 3. I just pulled these out as being somewhat emblematic of the typical well. Of course, there's a big spread of results. Some wells are better, some wells are worse. But these sort of fit in the middle, so I chose them as examples of

performance of individual wells.

Q. The first page, Number 161, does that show the effect of waterflooding on this well?

A. Yeah, 167, I think, pretty clearly shows some support from water injection. There's a production increase from the level, mid- to late 1996, up into 1997, that I think is clearly from water injection.

Q. Finally, with respect to the CMU, what is Exhibit 6?

A. Exhibit 6 is a spreadsheet, a table, showing all the wells that Wiser drilled in the unit, the first page. It has spud dates, first production dates, some other information, perforations and the initial potentials of the wells. The next three pages have that same information by phase.

Q. Now when you're drilling these wells and increasing the injection, would you have -- could it have been justified to just drill the infill producers alone without increasing injection at the same time?

A. No, we don't believe so. I don't think it would possible to economically drill just the infill wells. If you look at the original primary recoveries for the Caprock Maljamar Unit area, the average well recovered 42,000 barrels of oil.

Although we would probably have a better completion procedure at this point in time than they did back then, it's unlikely that we could recover 42,000 barrels on an infill well. There would be some drainage involved, and I think it would be more likely you would recover 20,000 to 30,000 barrels on an infill well in this unit.

Q. If there had been no new injection?

A. If there had been no new injection, if -- simply an infill project, which would not have been economical. And so we looked at the infill and the waterflood, really, as a combined project, difficult, probably impossible to separate the two.

You couldn't rearrange the waterflood patterns to do any good, because the previous waterflooding had basically run its course, and the sweep efficiencies were about as good as they were going to get using the existing wellbores. So you had to add some wellbores in an d rearrange the patterns to access the oil that was left behind, in between the patterns.

So, you know, the conclusion is that out of the 90,000 to 100,000 barrels per pattern on average that we expect to recover here, only 20 or 30 is probably from an infill program. The remainder would be the effect of rearranging the injection patterns --

Q. And increasing the --

A. -- and increasing injection, increasing density and injection, correct.

Q. Okay. So in short, although it's hard to separate out the effects, you really needed to drill and increase injection simultaneously?

A. Correct.

Q. And that would maximize the production from the unit?

A. That is correct.

Q. Okay. Now again, you've said it's not easy to separate the old and new effect, but is there a correlative project which helps show the effect of increased flooding and production?

A. There is. There's one example that I've found in the area, that Artesia Vacuum trend, Grayburg-San Andres trend, where there's a lot of projects that are similar to this, and that is over on the Devon-operated Turner B lease.

And I have -- Exhibit 7 is a cross-section, it's a rather large -- but if I might point out just a couple of things for you here on this cross-section.

Q. I think the line of the cross-section is given in the upper left of this?

A. I'm sorry?

Q. The line of the cross-section is in the upper left of this?

A. Right. If you look at the map, the A-A' on the west side is actually the Turner B Number 135, which is actually adjacent to Wiser's Skelly Unit, on the west of Wiser's Skelly Unit.

Q. And the Skelly Unit, we will discuss that?

A. We'll discuss it in just a few minutes. And there's two Skelly Unit wells on the west side of the unit, and Well 255 is kind of on the east side of the unit. And then we move across further to the east and pick up CMU 187, which is a well on the west side of the Caprock Maljamar Unit. 181 is then on the eastern side of the Caprock Maljamar Unit.

And I built this cross-section, really, just to demonstrate that across this area, this Artesia Vacuum trend, we're looking at the same geologic units across many miles.

If you look, I guess, at the second-from-the-bottom top, that is marked as the San Andres, that's a pretty clear marker throughout the area where you go from these sandy dolomites in the Grayburg section to a clean dolomite in the San Andres, and you can see that that's pretty clear all the way across. The Lovington is that blue marker at the bottom. That's a marker that's also pretty clear. And then at the top, I believe that's a

Queen sand, the green, that's pretty clear all the way across.

The sands within the Grayburg section themselves, I picked one and marked it in pink. I didn't name it. There's different local names for the sands within the Grayburg. Some people have names for them, some people have numbers for them. So I didn't note this, but you can see how the sand character continues across.

The thicknesses of the units don't change a whole lot across, and many of the sands appear to carry all the way across.

I would, though, mention that obviously this is not to scale horizontally. There's a lot of distance between wells. And in fact, some of these sands come and go. As you know, there's a lot of heterogeneities out here, and even some sands that do appear to be correlative may not be continuous between wellbores.

But I think basically the point we're trying to make is that this is the same animal and that the conclusions that I can draw from the Turner B can be used to describe what's happening in the Caprock Maljamar Unit --

Q. So the same --

A. -- as far as infill drilling and waterflooding is concerned.

Q. -- the same sands that are being flooded in the Turner B and the Skelly Unit and the Caprock Maljamar Unit are the same?

A. That is correct.

Q. Okay. Well, let's go on to your next two exhibits, then, 8 and 9, Mr. Eagleston, and --

A. Right.

Q. -- tell the Examiner how you determine that there is an effect from the increased injection in this area.

A. Okay, you might kind of pull those out and look at those side by side. The reason that this area is important an interesting to study is that in the early 1990s Devon's predecessor drilled 22 wells in the Turner B lease, 20-acre infill producers. They did not convert the offset injectors. And so it would be the case of just drilling the wells without doing the injection side of the plan.

A bit later, after Devon acquired the properties, if you look at Exhibit 8, in 1996 Devon drilled some additional wells on the Turner B. I believe there's 15. This is a type curve of the 22 and a type curve of the 15. And you can see that they started and actually looked quite similar in terms of initial rates and decline profiles and so forth. But then they start to look a little bit differently when you start to see the effect of the water injection.

And that's where Exhibit 9, where I backed them up so that they're normalized timewise. And you can see that they're very similar early on, but as water injection begins to take effect, the later wells, which were receiving injection support earlier in their lives, are beginning to increase above the trend line established by the older wells.

And if you glance back at Exhibit 8, you can see that, in fact, the older 22 wells are beginning to see some effect, apparently, from the increased injection support as well.

This is the only case that I know of where you have a substantial number of wells in the same area where some were drilled and had no injection support for some period of time, and then another later group was drilled with injection support, and you have this kind of comparison available to you.

Everywhere else that I'm aware of, it was done like we did, which was simultaneously.

Q. Does this support the conclusion that there has been a positive production response in the CMU?

A. Yes, I believe it does.

Q. Well, let's move on to the next -- actually, the next three cases, having to do with the Skelly area, Mr.

Eagleston. Would you identify Exhibit 10 for the Examiner?

A. Exhibit 10 is a map of the Skelly unit area. The legend, the symbols and so forth are the same as what we used in the Caprock Maljamar Unit map earlier, so the purple dots represent wells that Wiser has drilled, and the red dashes represent the waterflood patterns that have been established.

Once again, we did have to drill -- redrill some wells for injection purposes, we had to re-enter, in fact, nine P-and-A'd wells, we converted 47, did work on many others, in order to establish these patterns.

The yellow area is actually the Skelly unit proper. The green is the Lea "D" lease, which is adjacent to and is served by the same injection system and is really incorporated into the Skelly Unit development plan. And the blue, up on the northwest side of Skelly, is the State "AZ" lease, and has also been incorporated into the injection plan.

Q. And Mr. Eagleston, immediately to the west of the Skelly Unit is the Turner B lease; is that right?

A. That is correct, that is correct. And the State "AZ" well, in purple, is the State "AZ" Number 3 and was actually drilled as a leaseline cooperative well with Devon, and was drilled in the corner of their lease and the State "AZ" lease and the Skelly unit, to situate it into most advantageous position for recovery out of that pattern, and we support that pattern with injection from the Skelly Unit and also from the Turner B lease.

Q. And Wiser and Devon have several other wells along their lease line that have been drilled as cooperative wells?

A. That's correct, we drilled a total of seven. Devon operates three, the 134, 135 and 136 that you see just west of the lease line. And then if you look a bit further south, the 400, 401 and 402 were drilled and operated by Wiser.

Q. Okay. A couple of final questions. On this map, what does -- what numerical sequence identifies new injectors that you drilled?

A. The 300-series wells. There's a couple -- the Number 3- -- Let me find it here. The Number 300 is on the east side of the unit. It was drilled as a replacement for Number 71. There's a -- Number 301 is on the west side. It was drilled as a replacement for Number 92. We also drilled Number 302 as a replacement for Number 91. We are currently producing that well, but it will be converted to an injector. It was drilled as an injector.

Q. So it wasn't just that new producers were drilled in this area either?

A. No, no, absolutely not. We drilled -- To kind of go over the same kind of statistics that we did on Caprock Maljamar Unit, the Skelly unit is a little shallower, so it was less expensive to develop.

Also, the injection system that our predecessor, Texaco, had left behind was in much better condition. So it didn't cost as much money for us to do the development at Skelly. We spent approximately $358,000 per pattern, as opposed to the 586 over at CMU. Of the $350,000, about $230,000 goes to drill an infill well on average. That means we spent about $128,000 on injection, or about 35 percent of the capital was spent on the injection side of the --

Q. Why don't you move on to Exhibit 11 and do what you did with the CMU and just discuss a little bit of the history of this area and the costs involved in this project.

A. Uh-huh. The Skelly Unit, or the first well drilled in what became the Skelly Unit was drilled in 1926. It's now Skelly Unit 41. And that area, as was the case throughout this trend, was developed on 40-acre spacing over the next 30 to 40 years.

In 1965 a pilot waterflood was installed. It worked very well, so it was expanded to the rest of the unit in 1968. Active waterflooding continued until the late 1980s, when they ceased injecting makeup water and it became simply a disposal operation, similar to what we saw over at the Caprock Maljamar Unit.

Wiser acquired the property from Texaco in 1995. Production was down to 250 barrels of oil per day from 66 active wells. There were 18 injection wells recycling the produced water. And once again, this is close to the economic limit. There was not much in the way of reserves left at that time under existing operating conditions.

So we started shortly after we acquired the properties in late 1995 with the development program that included drilling a total of 77 producers and converting the numerous wells and re-entering plugged wells and so forth to create these 40-acre fivespot patterns.

Our production peaked at a bit over 2300 barrels a day in early 1997. We came in and did a bit more work in late 1997, and by November of 1998 production was averaging 1036 barrels a day, about 7300 barrels of water a day, from 108 active producing wells.

And I need to make a note here that on the Skelly Unit the shallower Seven Rivers interval is also productive and, in fact, until recently was a separate reservoir called the Fren-Seven Rivers reservoir. Devon -- The reservoir basically was on the Skelly Unit and the Turner B. Devon had petitioned previously to abolish the Fren-Seven Rivers and combine it into the Grayburg-Jackson reservoir. And so it was.

But we still have a number of shallower Seven-Rivers-only wells on the lease, and that's why we have 108 active producing wells. There's only actually 77 active Grayburg wells. The remainder are those shallow Seven Rivers wells, which we are not actively waterflooding at this time. We're actively waterflooding the Grayburg and the San Andres.

We also are injecting about -- in November injected almost 15,000 barrels a day into 81 active injectors. Once again, we're getting makeup fresh water through Conoco's system in the area.

Moving on to the Lea "D", the Lea "D" is adjacent to the Skelly Unit, as we noted on the map. It was part of the original Skelly Unit waterflood. The plant and injection system were tied together. At the time we acquired the property, actually from Apache in 1997, they had acquired it from Texaco previously. Production was from only well, five barrels a day. Injection had ceased long ago. And we instituted an infill development program and drilled six wells, converted seven wells to injection, and are now making 84 barrels a day and 374 barrels of water a day, and injecting almost 1200 barrels a day there.

And the State "AZ" lease on the northwest part of the Unit is a 40-acre tract. Once again, we acquired that from Apache in 1997. We drilled a single well down in the corner of that 40-acre tract to develop reserves along the lease line and provide a take point for a pattern along the lease line that we share with Devon. The well in November of 1998 -- actually, that well plus the wells that were already on the lease, were averaging 47 barrels a day, about 20 barrels of water per day.

And we support -- although there's no injection directly on the State "AZ" lease, we support that pattern with between 200 and 300 barrels a day of injection from the offsets in that pattern. So it is an integral part of our waterflood plan.

The third page in this exhibit is a data page, once again. It gives well counts by lease, injectors and producers, injection volumes. Those volumes, as I note here with the asterisk, excludes offset injection. Those leaseline wells, including the State "AZ", are supported by injection from the Devon side, and that's not included in our --

Q. This project is ultimately a little more profitable than the CM Unit?

A. Yeah, it's going to be substantially better from a financial perspective. We didn't have to spend as much money, and it's performed better as well, so it is going to turn out to be a better project.

Q. Why don't you go to Exhibit 12 and discuss the extra production you hope to get out of the project.

A. All right, this next group, Exhibit 12, is a group of decline curves by -- Well, the first one is the combined Skelly-Lea "D"-State "AZ" curve, and then behind that you have a curve for each of the leases, which shows the same information that we presented for the Caprock Maljamar Unit.

It shows production prior to our development program, with the red line being an extrapolation of what production would have done had we not redeveloped the area. Once again, production actually would have ceased probably prior to that, the end of that red line, due to just becoming uneconomic.

Q. What -- Do you have another figure on reserves you hope to recover with this project?

A. Right, in the Skelly area incremental reserves are estimated to be about 7.5 million barrels. And once again, kind of using some of the same analysis that we looked at on the Caprock Maljamar Unit, the average primary per well in the Skelly area was 52,000 barrels, a little bit better than Caprock Maljamar.

Once again, though, I think it would be unlikely to recover a similar amount from an infill well, due to partial drainage. So I would estimate 25,000 to 35,000 per infill well would be reasonable to expect with no additional injection support.

Once again, our estimates on a per-pattern basis approach 100,000 barrels, so the remainder, 65,000 to 75,000 barrels, would be attributable to the reactivation of the waterflood and rearranging the waterflood patterns.

Q. In your opinion, is this project economically and technically feasible at this time?

A. Yes.

Q. And in your opinion, was it prudent to expand the waterflood projects to maximize the recovery of crude oil?

A. Yes.

Q. And will these projects lead to the recovery of an increased amount of crude oil which will ultimately be recovered from these formations?

A. That is correct.

Q. Do you consider these projects to be significant expansions of the projects Wiser purchased in the 1990s?

A. Yes.

Q. By increasing the infill drilling, you are in effect increasing the geographic and geologic area you are recovering reserves from; is that correct?

A. Well, we're contacting and recovering oil that was not recoverable with previous spacing and operational practices.

Q. Because of the heterogeneity of the reservoir?

A. That is correct. And I would point out too, in the case of the Caprock Maljamar Unit -- this is kind of going back to that -- that in addition to the better connectivity created by the tighter spacing, we also -- or the previous waterflooding in many areas of the unit was on the Grayburg only, and we deepened a number of the other injectors to include the upper member of the San Andres, the Vacuum, locally known as the Vacuum, and we are waterflooding the Vacuum and the Grayburg. So we added the Vacuum in many areas of the unit as well. It was not waterflooded previously.

Q. What is contained in Exhibit 13, Mr. Eagleston?

A. Exhibit 13 is, once again, just some examples, individual well decline curves for this area.

Skelly 189 is sort of in the northern part of the unit. It's been very well supported, I think, by injection, essentially flat.

266 is down in the southern -- southeastern part of the unit, and I think once again you can see some injection support there.

And 273 is on the western side of the unit and has been also a very good well that has seen some injection support.

The State "AZ" Number 3 is a relatively new well.

It looks like it's going to be a very fine producer, but it's a little early to see what kind of injection support might be apparent on the curve.

And I guess I ought to stop and point out, when I say that injection support is apparent, that's from a classic waterflood standpoint where production actually goes up. In many cases here, you're not going to see that on an individual well basis, because you're immediately in a drag-flood situation. And so what you get is perhaps a shallower decline than would have been seen before, but not necessarily a classic secondary response. Just like to point that one out.

And then in the final well, individual decline curve that we have, is one of the Lea "D" wells, the Lea "D" Number 20.

Q. What is Exhibit 14?

A. Exhibit 14 is a spreadsheet of all the wells that Wiser drilled in this area, Skelly, Lee "D" and State "AZ", with spud dates, first-production dates, perforations, potentials and so forth, just a listing of all the wells.

Q. And finally, what is Exhibit 15?

A. And Exhibit 15 is just the tabular data that was presented in graphical form earlier, the production and injection data for the three leases in the Skelly area, as well as the Caprock Maljamar Unit.

Q. Just backup for what you previously --

A. Just backup, that's correct, backup for the graphical data,

Q. Okay. In your opinion, are the three Skelly area leases or units qualified for an EOR, enhanced oil recovery, credit?

A. Yes.

Q. Were Exhibits 1 through 15 prepared by you or under your direction?

A. They were.

Q. And in your opinion, is the granting of these four Applications in the interests of conservation and the prevention of waste?

A. Yes, it is.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibits 1 through 15 into the record.

EXAMINER CATANACH: Exhibits 1 through 15 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Eagleston, most of the work in the CMU involved infill drilling producers on 20-acre spacing; is that correct?

A. Right. And converting all the existing or older offset producers or injectors to active injection service.

Q. Do you know how many wells were converted to injection?

A. We -- and these numbers actually may be off a well or two here -- we re-entered eight P-and-A'd or TA'd wells and converted them to injection. We converted 50 existing producers or shut-in producers to injection. We drilled ten new wells as injectors, and we also worked on 12 wells that were existing injectors, either deepening them or adding perforations, stimulating, so forth.

So we now have a total in -- Well, in November of 1988 we had 82 active injection wells. And when we took over the project, there were 16 wells that were actively injecting water, recycling produced water. So we added 66 wells beyond that 16. In addition, we worked on 12 out of those 16 in some fashion. So we essentially worked on every well in the unit, with a few exceptions.

Q. So you actually did an extensive amount of work to the injection wells?

A. Absolutely. Yeah, we spent, out of the capital -- I think I gave you a 35-percent number on Skelly. The comparable number at CMU is 45 percent; 45 percent of the total capital expended was for injection purposes. That included working on the wells, and a brand-new -- two totally new injection plants and a totally new injection -- fiberglass high-pressure injection system was installed here.

Q. Now, all of that work was done in all three of the phases?

A. That's correct. Yeah, we have two separate injection plants. Because of the funny shape of the unit, there's one plant that just serves that little southern appendage down there. It's a smaller plant. And then there's another bigger plant up kind of in the center of the main body of the unit. And as I mentioned, both those plants were -- we had to basically start from the ground up, from the concrete slab up. The old facilities were simply not usable.

I guess I could point out too, as we did on the Skelly unit, we have some leaseline wells. We have a leaseline agreement on the northeastern part of the CMU with Shahara. They operate a three-hundred -- the western half of Section 16 there. And they drilled and operate Well Numbers 100 and 101. We drilled 400 and 401 and -- to help -- or to develop the reserves along the lease line. That was part of their development program for their 320 acres that was unitized in the last few months, I believe.

Q. Okay. So within Phase 1 you guys started injecting in about May of 1994?

A. That's correct. Yeah, I can tell you the injection start dates. The -- Yeah, injection start date, May of 1994 for Phase 1. For Phase 2, November of 1994, which was contemporaneous with the certification date. Phase 3, first injection actually was in October of 1996. Certification came in October of 1997.

Q. Okay. So in Phase 1, you actually started to get an increase in production before you started injecting, right?

A. There were some infill wells drilled --

Q. Right.

A. -- that is correct.

Q. Okay, and your position is that you can't separate the effect of increased production on infill drilling and on waterflood response?

A. I can make an estimate, and my estimate would be, as I mentioned, kind of going back to the original primary production and looking at that, saying, well, we have 42,000 barrels a well there, you're not going to infill drill and do any better than that, most likely, unless you had a major leap forward in completion technology.

And although we -- I think we probably could do a better job, I still would think it would be more reasonable to think that you would get maybe 20,000 or 30,000 barrels per well, with no injection support, mind you. So that's about the best analysis I can do, probably, in trying to separate that.

Q. Okay, go over those figures again. You estimate 42,000 --

A. The average primary recovery per well in the unit area was 42,000 barrels. And I think given the state of depletion, my experience with these kind of reservoirs, I think getting between 50 and 75 percent of primary on a pure infill-only case is a reasonable thing. So that would make it between 20 and 30 or so. I'm rounding the numbers a bit.

Q. Okay, and you're estimating -- with waterflood operations, you're estimating 100 barrels?

A. We actually started out at 110, and as things have gone along a bit, we've backed that down closer to about 95, actually, per pattern.

Q. Now, when you say "per pattern", that's one producing well?

A. That's correct.

Q. Okay.

A. So I would -- you know, I would place the reserves attributable to the waterflooding part of the project at the difference between 95 and, you know, 20,000 to 30,000 barrels.

But once again, in our view the two really can't be separated because you wouldn't drill for 20,000 or 30,000 barrels. You couldn't drill a $325,000 well for

20,000 or 30,000 barrels, because it would also be a fairly low-rate well.

And by the same token, you couldn't rearrange the waterflood using existing producers and really add much either. They had done about all they could in the 1960s and 1970s utilizing those wellbores. So what you had to do was add some wellbores so you could rearrange your patterns to recover incremental oil. So they really just go hand in hand.

Q. Okay, you're estimating a response date for Phase 1 of October 1st, is that -- How did you get that?

A. A response --

Q. Yeah.

A. -- of -- Yeah, October of 1994.

Q. October of 1994.

A. Yeah, that was purely, if you look at the Phase 1 decline curve -- and of course it doesn't go back previously, but the first thing that we did was that jump up in production in mid-1993, okay. There was actually two wells drilled -- No, I'm sorry, there were four wells drilled in the unit prior to unitization, and that's what that jump up in production is in mid-1993.

So production prior to our arrival in Phase 1 was at the -- you know, a little over 100-barrels-a-day level. Okay. So you could -- And it was declining at the rate of about five, six, seven percent, somewhere in that neighborhood.

So if you draw a line along there, what I looked at, I said, Well, okay, this 1993 stuff, that was before the unit was formed. We really didn't start injecting until May, then you see a large jump in production in late 1994. And I picked that point which is in October, which is where we were at about 300 barrels a day, as being at a point that was clearly and demonstrably above the previously established decline, which would have been still at around 100 barrels a day. So you were a couple hundred barrels --

Q. Are we looking at the same exhibit? I'm sorry, are you looking at the Phase 1?

A. Uh-huh, yes.

Q. Okay.

A. Right. I'm sorry, I should have annotated that a bit more.

Q. Well, I'm not sure about your scale on the -- you're using a --

A. These are barrels per month on the scale.

Q. Okay.

A. Yeah, so we're at -- The bottom is at 1000, so production was at about -- a little over 3000 barrels a months. So just a tad over 100 barrels a day. I switched back and forth, sorry. It was about 3000 barrels a month before we arrived on the scene.

Q. Okay.

A. And the typical decline out there was around five to seven percent at that time, so it's declining at five to seven from that point forward.

And I picked November -- or, I'm sorry, October of 1994 as a proposed date of response because that's a point where production has clearly departed in a substantial way from the previous decline trend that -- if you drew a line on there, I mean, it's going to look something like this, Mr. Examiner. You know, this decline is going to be something like this. And so I just picked a point where there would be no question that we were well above that line, which is this point right here. And I'm sorry, I should have annotated that on this graph.

Q. Let me make sure I understand you. Your bottom scale --

A. Uh-huh.

Q. -- where it says 1994, is that -- Exactly what is that?

A. Well, that's just a time scale. That's 1994.

Q. Where it says 1994, is that a particular month?

A. Yeah, January is on the -- is the divider. So the grid where you have this line that goes all the way up the graph, that's January. So February, March, April, May, June -- Where the number 1994 appears would be July. So August, September, October is that point right there on the graph. And I'm sorry, I'm not making myself clear, but --

Q. Oh, I got it.

A. You got it?

Q. Uh-huh.

A. Okay, yeah.

Q. I just needed a month for that --

A. Right.

Q. -- to see where that was.

A. Right, yeah. Yeah, on this particular graph -- and I know it's different graphs, but January is on the gridline. And I used the same, you know, kind of thinking to pick the positive production response dates for the other two phases as well. I looked at what the established trend line was and picked a month where production had clearly departed and was substantially above that trend line

Q. Okay, for Phase 3, you don't have anything until January 1st of 1998?

A. Right, and the reason there is, the certification did not occur until October of 1997. And although we started injecting in that phase in October of 1996, the certification date was October of 1997. So that's why I picked the January of 1998 date, having to pick a date subsequent to the certification date.

Q. Okay, and we'll talk about the Skelly a little bit.

A. Okay.

Q. This is the first attempt you've made to qualify these areas for the EOR tax credit?

A. Well, we made a -- I guess Mr. Bruce could probably speak to that. We had sent some materials in previously, requesting administrative approval of this. But I think it was determined that a hearing would be required.

Q. Okay, most of this work was performed --

A. 1996 and 1997. We started at the tail end of 1995.

Q. And this was in an area that had already been waterflooded previously as well, right?

A. That is correct.

Q. Texaco had flooded this area?

A. Right, it was actually a Skelly, *ergo* the Skelly unit name. Skelly actually had the property from way, way back, and it made its way eventually into Texaco's hands. But it followed a development pattern identical, really, to the Caprock Maljamar Unit. All these units along this trend line were developed and waterflooded during the same time frames.

Q. Okay. So basically what you did in this whole area is the same thing, you infill drilled on 20-acre spacing?

A. That is correct.

Q. There was a lot less work that you did on the injection wells --

A. Right.

Q. -- in this unit, though?

A. Right, we -- a couple of -- or, well, the main reason there on the injection system was that Texaco -- the Texaco injection system itself was in much better condition, and we were able to use it with less work, less modification required.

But as I mentioned previously, still 35 percent of the total capital expended -- which we spent, I think, about $27 million -- 35 percent of that still went to the injection system. We re-entered -- kind of giving the same stats that we talked about with Caprock. We re-entered nine P-and-A'd or TA'd wells, to convert to injection. We converted 47 existing or shut-in producers to injection. We worked over 11 of the existing injection wells, and we drilled three wells. And there's a total now of 88 active injection wells.

Q. Do you guys have those numbers somewhere in your exhibits, or is that just something --

A. That's just some notes I made. I can provide that for you, though.

Q. Yeah, would you, please?

A. Okay. I would like to go back and double-check a couple of them. I think I mentioned I might be a well or two off, but I'll get the exact numbers and provide them to you.

Q. Did you guys significantly increase the injected volumes in this area?

A. Oh, yes, yes. Whenever we -- As I mentioned, in the late 1980s they had stopped injecting makeup water, and it was simply a recycling project. So in 1995 when we acquired the property, they were producing 250 barrels of oil per day and 650 barrels of water. That was it, 650 barrels of water a day was all that was being injected. In November of 1998 we injected almost 15,000 barrels of water a day.

Q. Now, as I understand it, the Seven Rivers is now within the same pool in this --

A. It's in the Grayburg, it's been combined into the Grayburg-Jackson Pool.

Q. Okay, but the Seven Rivers is not being flooded?

A. Not currently. It has been flooded previously, and we actually do have some plans to go in and reactivate a portion of that. We haven't done so yet. A little matter of low oil pricing at the moment has deterred us.

Q. Are you suggesting that -- If we choose to certify this as an EOR project, in your opinion have we already seen the same positive production response as we have --

A. Yeah --

Q. -- similarly in --

A. -- using the same thinking and analysis, yes.

Q. And do you have suggested dates for those responses?

A. I do, and you could refer to the decline curves by lease. I can give it to you by lease here.

MR. BRUCE: Exhibit 12.

THE WITNESS: Yeah, this is Exhibit 12. On the second page of Exhibit 12, the Skelly Unit decline curve, we would suggest that June of 1996 -- and actually it might be easier to see, Mr. Examiner, on the tabulated data, which is Exhibit 15, because these decline curves are kind of squeezed together. But we would suggest June of 1996 for the Skelly unit. We would suggest November of 1997 for the Lea "D" and May of 1998 for the State "AZ".

Q. (By Examiner Catanach) I think I've got those numbers on the primary for that area.

A. Yeah, it was 52,000 per well on primary in the

Skelly unit.

Q. And 25,000 to 35,000 infill?

A. Yeah, that's once again using that kind of a 50- to 75-percent recovery on 20-acre infills versus the 40-acre primaries.

Q. Okay, and again, you're looking at 100,000 per pattern?

A. We're looking at -- It's actually about 95,000.

Q. And do your decline curves for those areas, do they support those numbers?

A. Yeah, they -- Once again, Exhibit 12, the yellow projection, that projection will get you the 95,000 per well.

As I mentioned, in Caprock we actually had to reduce our reserve estimate in Caprock slightly. At Skelly we have not.

Q. Okay. Mr. Eagleston, do we have a list of all the producing wells in both of these areas that would qualify for the EOR tax?

A. I believe in the case of the Caprock Maljamar unit, which was certified in phases, that you do have that information, but I could certainly provide that again if necessary. And in the case of the Skelly unit, let me just check. I'm not sure in the materials we submitted previously whether we had that information or not. Well --

Q. I'll tell you what, why don't --

A. I'll provide it in any case, if that's --

Q. What I'm going to need is, within the Caprock Maljamar Unit, just a list of the producing wells that I can send to Taxation and Revenue saying that these wells qualify for the EOR tax credit.

A. Okay.

Q. I need all of the wells, including API numbers for the wells.

A. Okay.

Q. And you might as well do that for all the Skelly-area wells as well --

A. All right.

Q. -- in case we decide to do that.

A. Yeah, as I mentioned, the two projects are really carbon copies of each other and are quite -- they're a carbon copy of the Devon project that adjoins Skelly on the west. They did exactly what we did --

Q. Okay.

A. -- which I think you guys have dealt with previously, if I remember correctly.

EXAMINER CATANACH: Jim, if you don't mind doing some rough orders, not -- You don't have to do anything elaborate, but just make sure I have the dates and the important things covered in the orders, make sure that we have them right.

MR. BRUCE: Will do.

EXAMINER CATANACH: Okay, I don't have anything else.

Is there anything else?

MR. BRUCE: I have nothing further in this matter, Mr. Examiner.

EXAMINER CATANACH: Okay, there being nothing further, Cases 12,147, 12,148, 12,149 and 12,150 will be taken under advisement.

(Thereupon, these proceedings were concluded at 2:15 p.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 12147, heard by me on March 18 1999.

______, 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 22nd, 1999.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002