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 BP AMERICA PRODUCTION COMPANY FOR APPROVAL OF A WATERFLOOD PROJECT, EDDY COUNTY, NEW MEXICO

CASE NO. 13,750

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

2006 AUG 17 PM 1 41

BEFORE: WILLIAM V. JONES, JR., Hearing Examiner

August 3rd, 2006

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, JR., Hearing Examiner, on Thursday, August 3rd, 2006, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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August 3rd, 2006
Examiner Hearing
CASE NO. 13,750

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EXHIBITS

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A P P E A R A N C E S

FOR THE DIVISION:

CHERYL O'CONNOR
Assistant Counsel, NMOCD
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

HOLLAND & HART, L.L.P., and CAMPBELL & CARR
110 N. Guadalupe, Suite 1
P.O. Box 2208
Santa Fe, New Mexico 87504-2208
By: WILLIAM F. CARR

* * *

ALSO PRESENT:

JACKIE BREWER
HC-60
Lovington, NM 88260

* * *

WHEREUPON, the following proceedings were had at 8:23 a.m.:

EXAMINER JONES: Okay, the next case is Case 13,750, continued from July the 20th, Application of BP America Production Company for approval of a waterflood project, Eddy County, New Mexico.

Call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe office of Holland and Hart, L.L.P. We represent BP America Production Company in this case, and I have one witness.

EXAMINER JONES: Okay, one witness.

Any other appearances here today?

Mr. Carr, we did get a letter -- I don't know if you got a copy of it -- a letter that got faxed over to -- from a Jackie Brewer.

MR. CARR: Yes, we have looked at the letter and will respond to the letter as part of our direct case.

EXAMINER JONES: Okay, will the witness please stand to be sworn?

(Thereupon, the witness was sworn.)

MR. CARR: May it please the Examiner, before we begin, for some reason when we were preparing the legal ad and the Application in this case I added a well that is not supposed to be part of the Application. It's the

Washington 33 State Well Number 14. And so that well should be dismissed from this case. I put it in and I have nothing to present in support of it. It's just my mistake.

EXAMINER JONES: Okay.

JEFFREY HARGROVE,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. My name is Jeffrey Hargrove.

Q. Mr. Hargrove, where do you reside?

A. I live in Houston, Texas.

Q. By whom are you employed?

A. I do contract consulting engineering work for BP America Production Company. I'm self-employed.

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

A. Yes I have, in the early 1990s.

Q. Not before Mr. Jones?

A. No, sir.

Q. Why don't you summarize for us your educational background?

A. I have a bachelor's in petroleum engineering from the University of Missouri, Rolla. I graduated in 1988.

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

A. I've worked for ConocoPhillips, Batch Corporation, Baker Hughes. I currently have my own consulting company. I've worked about 18 years as mostly petroleum reservoir engineering -- doing petroleum reservoir engineering work -- take a deep breath -- mostly on field development projects, about six to eight years international, 10 years of domestic experience, including waterflood projects, secondary recovery projects and also including projects in southeast New Mexico.

Q. Are you familiar with the Application that's been filed in this case on behalf of BP America Production Company?

A. Yes, sir, I am. I actually prepared the Application.

Q. And are you familiar with BP's plans to implement a lease waterflood project in the Artesia-Queen-Grayburg-San Andres Pool --

A. Yes.

Q. -- located in Eddy County?

A. Yes.

Q. Are you familiar with the status of the lands in the area that's the subject of this Application?

A. Yes.

Q. And have you made an engineering study of the area?

A. I have.

Q. Are you prepared to share the results of that work with Mr. Jones?

A. Yes, sir.

MR. CARR: We tender Mr. Hargrove as an expert witness in petroleum and reservoir engineering.

EXAMINER JONES: Mr. Hargrove, what is your specialty in petroleum reservoir engineering?

THE WITNESS: I -- Mostly like field development projects. Usually -- I've worked in the mid-continent, Permian Basin, worked in west Africa, usually with the exploitation teams offering a reservoir engineering perspective in terms of the best way to exploit the reservoir in terms of development drilling, best way to drill and complete the wells, to basically develop the reservoir. I've also done secondary recovery projects in west Texas and southeast New Mexico.

I'm not a -- I've done some reservoir simulation, some specialty reservoir engineering, but I would call it more in the field development type of work.

EXAMINER JONES: What did you do for Baker Hughes?

THE WITNESS: Actually with Baker I consulted mostly within these international -- a lot of times they were the -- it was the -- like the reservoir engineering groups in these foreign countries that -- like a BP or an Exxon would be partnering up with on a project, whether it's west Africa, I did a lot of work in Latin America, do work for the Chinese National Offshore Oil Corporation, some stuff in the North Sea.

So what I would do is, I would go in there and I would add a reservoir engineering perspective to the project and make recommendations on the best way to drill and complete the wells, to optimize well performance and -- all kinds of different -- you know, different kinds of, like, complex geologies, heavy oil, deep water -- deep-water applications. You know, there's always different geologic, environmental conditions that -- But these were large-scale projects, the Latin American projects. I also did a lot of work for PMEX down in Costa Rica and Veracruz, some -- with Baker Hughes it was almost all international.

EXAMINER JONES: Okay, thank you.

THE WITNESS: You're welcome.

EXAMINER JONES: Mr. Hargrove is qualified as an expert petroleum reservoir engineer.

Q. (By Mr. Carr) Mr. Hargrove, briefly summarize for Mr. Jones what it is that BP America Production Company seeks with this Application?

A. With this Application BP wishes to implement a lease waterflood on the Washington 33 State Lease for the purpose of secondary recovery of oil and gas.

Q. How many wells are we seeking authorization for in this case?

A. With this Application --

Q. Yeah --

A. -- six wells.

Q. Before we get into the technical part of the case, I think we ought to clarify for the Examiner exactly where we are in terms of how the Application was filed and what we have before him today.

When was the original C-108 actually filed?

A. In May of this year we filed the original C-108 application, application to convert the Number 2, Number 6, 8, 16, 23 and 27 to water injection.

Q. And then after you filed that application, did you continue your reservoir analysis?

A. We didn't so much continue the reservoir analysis as we started to put together a reservoir management program and put this lease waterflood in, and at the same time we started to map, flesh out, a strategy to manage -- to monitor the injection production and to manage the waterflood.

And it was at that time, looking at it, we thought that BP would be better served by converting three different wells to water injection, tightening up the pattern, and it was at that time that we filed the addendum. So we took out the 6 and the 8 and the 27, replaced it with the 4, the 10 and the 18. So that's when we filed the addendum C-108, a continuation sheet that addressed all the different questions, and also the well injection data sheet, which I think is part 3.

The area of review actually shrunk a little bit, so we didn't have an expanded area of review, so there wasn't a well data table, P-and-A wells or anything like that, so --

Q. All of that data was the same, you just had deleted three wells, replaced them --

A. Exactly, yeah.

Q. Okay, identify the wells that we're addressing here today by number, please.

A. Okay, Number 2, Number 4, 10, 16, 23 and 18.

Q. Now, there's one other well on this waterflood project that's been previously approved by the Division?

A. That's correct, that --

Q. That is the -- Which well is that?

A. The Washington 33 State Number 12. It was approved administratively with the NMOCD, SWD-988 Division Order.

Q. And so if this project is approved, you will have seven injection wells, the six we're dealing with here today --

A. Right.

Q. -- plus the Number 12?

A. We'll have seven injection wells, 22 production wells.

Q. Let's go to what's been marked as BP Exhibit Number 1, and I ask you to first identify this and then explain to Mr. Jones, what does it show? And he has a copy, so...

A. Okay, this is -- this map depicts, first of all, the Washington 33 State Lease, the boundaries of this lease as depicted by this bold red line. But you've got, I'd say, approximately 600 acres. You've got all of Section 33, except for the northwest northwest 40 acres.

The Number 12 is at the center of the lease. That's the well that we received approval to convert to water injection, and we're currently injecting into that well right now, monitoring the injection rates and pressures.

The triangles, the red triangles, are the -- depicts the six wells that we are asking to convert to injection for this Application, 2, 4, 10, 16, 18 and 23.

Q. The red line around the project area, what does that show?

A. The red line is a composite area of review. You've got six wells that we're proposing to convert to injections, and you've six different one-half-mile-radius area of reviews. To keep a lot of circles -- we just made a composite area of review, that those are one-half-mile-radius circles around the proposed injection wells.

Some of these other boundaries or other waterflood units in the Queen-Grayburg-San Andres formation, so the Washington 33 State Lease is actually surrounded by mature lease waterfloods in this reservoir.

Q. Now --

A. All the wells -- This map also depicts all the wells that penetrate the proposed injection interval within a two-mile radius, as required by the C-108 application. You've got the operator, the well number, the last five digits of the API number, and then the total depth of the well. Each well should depict that information.

Q. As you go forward with this project, may you -- is it possible that you'd want to add some additional injectors?

A. It is possible, we would --

Q. And you would propose to do that by an administrative procedure --

A. An administrative --

Q. -- instead of coming back to hearing?

A. Yes.

Q. What's the current status of the six wells that you are intending to utilize for injection?

A. These six wells produce approximately 25 to 30 barrels a day total. They're basically four- to five-barrel-a-day Queen-Grayburg-San Andres production wells, primary, you know, recovery.

Q. And why is BP proposing to implement this lease waterflood project at this time?

A. Okay, right now the lease makes about 120 barrels of oil per day and has an economic life, even with the high oil prices of probably anywhere seven to eight years, you're going to cum about a hundred and -- 150,000 barrels of oil, if you produce this on down to the economic limit.

This is a good opportunity right now, with the high oil prices. You've got a crude oil that's got a good GO- -- it's got a lot of gas in it. The initial gas-oil ratio for this crude oil was 2000 MC- -- 2000 standard cubic feet per stock tank barrel.

We've produced this reservoir below the bubble point, so you've got free gas breaking out, which -- which is not a good thing for a secondary recovery project. You want to go ahead and get that gas back in solution, mobilize that oil and displace it.

With the secondary recovery project you can recovery probably anywhere from 1 million to 1.5 million BOE's, from this lease. And so it's -- you've got good wellbore, you've got good wellbore integrity out here. These are relatively new wells. This -- The Queen-Grayburg-San Andres was drilled up on this lease in 1998. Some wells were recompleted from the Abo and the Yeso, but overall the average age of the well -- of the wellbore, is about 15 years, 15, 16 years. So you've got relatively new wells, you've got good casing. So from a structural perspective it's a solid project.

You've got a good supply of injection water with the Empire-Abo Unit and the Washington 33 State Lease. And you've got -- you've got a reservoir that's continuous throughout the lease. You've got a really favorable GOR. You don't have a dead oil, you've got a -- you've got a gassy oil, but a -- that's losing gas every day. You've got free gas in the reservoir.

So the sooner you can go in there, push that gas back in the oil, mobilize it and displace it through these production wells, the better off you're going to be, from a reserve -- from an economic perspective and a reserves-recovery perspective.

And you've got a -- you know, you've got a lot of analogous waterfloods. This thing is surrounded by waterfloods, so --

Q. If the project isn't implemented, the 1.5 BOE -- most of it will be lost and wasted; isn't that correct?

A. Well, if you continue to produce this -- even with the high oil prices, you know, you produce this thing out to the economic limit on primary recovery, oil and gas. You're probably going to make 150,000 barrels of oil.

EXAMINER JONES: Is that ultimate or --

THE WITNESS: Yeah.

EXAMINER JONES: -- cumulative? I mean, ultimate or remaining?

THE WITNESS: That's remaining. Yeah, you've probably got about 150,000 barrels of -- that's in the ballpark, remaining recoverable reserves with the current development. You can't drill a well out there and be economic, you can't even work over a well.

You don't have enough reservoir energy to do anything with this but produce the reserves from the existing wellbores with the existing pressure, which is about 600 p.s.i., well below bubble point. And so you're just going to produce this down to an economic limit.

With the waterflood you could take that gas, put it back in the oil, you can probably produce 10 times the remaining primary recoverable reserves, with a leased waterflood. So from a -- it's very -- it's an economic product -- it's an economic project. The high oil prices allow BP to invest their capital now to put in -- It's a small waterflood, you know, 600 acres isn't a very big project. But with the oil prices where they are now, you can afford to go in there and spend the capital to develop this thing and pressure-up the reservoir and have a 22- to 25-year producing property, as opposed to a seven- to 10-year producing property on the primary.

Q. (By Mr. Carr) The boundaries of the project area --

A. The lease.

Q. Just the lease?

A. Yeah, yeah.

Q. Is BP America Production Company the only working interest owner in the area?

A. That's correct, BP has 100 percent of the lease.

Q. Okay. Now you stated that you're going to have total, at least initially, of seven injection wells?

A. Right, seven injection wells, 22 production wells.

Q. And the cum production to date has been what?

A. This -- this lease, this section, this -- the Queen-Grayburg-San Andres in this 600 acres has produced approximately 1 million barrels of oil and 2 BCF of gas.

Q. And you're hoping to add another --

A. Yeah --
Q. -- 1.5 --
A. -- and we're --
Q. -- or produce that much more?
A. Yeah, we're taking the gas and just dividing it by six. I think there's about 1.5 MBOEs. You'll probably have 1, you're going to probably -- you've got a good chance of matching your primary production. A lot of it is because this field was developed so late. Most of the Grayburg-San Andres was drilled out here in the 1940s, '50s and '60s.

For some reason -- You know, this lease was developed in the 1940s and '50s. There was a company that actually drilled some wells out here, produced about 250,000 barrels of oil, and then it was basically -- I won't say neglected, they just didn't drill. And then in 1998 ARCO drilled the Washington 33 State Lease wells.

But the problem is the reservoir pressure. You just don't have a lot of reservoir pressure.

You've got a good crude, you've got a lot of good gas in there, you've got a lot of natural characteristics of this crude oil.

You've got reservoirs that are continuous across the lease, which are excellent candidates, the rock is a really good candidate for waterflood, the crude is a really good candidate for waterflood, and you've got some nice wellbores to actually institute a waterflood in.

And the oil prices where they are now, BP can put the capital in.

Q. Mr. Hargrove, would you identify what has been marked as BP Exhibit Number 2?

A. Is this the application?

Q. Yes.

A. This is the original application.

Q. And it is dated May the 17th?

A. That's correct.

Q. Actually shows it was filed on June the 2nd?

A. That's correct.

MR. CARR: Mr. Examiner, what we have done is, we have numbered the pages in Exhibit Number 2, and pages 1 through 54 are the original application and supporting data, and then pages 55 through 64 are the addendum that Mr. Hargrove indicated they filed after they decided to alter the injection pattern.

Q. (By Mr. Carr) Mr. Hargrove, does the May 17, 2006, application, as amended by the addendum filed on the date of the 21st of June, does that contain all required information required by Form C-108?

A. Yes, sir.

Q. And have both of these applications been provided to all affected parties?

A. Yes, sir.

Q. You indicated that the change that resulted from the addendum actually decreased the areas of review instead of expanding that area?

A. That's true, yeah, the three wells that we took out of the -- from the initial application, the 6, the 8 and the 27, by coming in to the 4 and the 10 and the 16 we shrunk the area of review slightly, that's true.

Q. Could you describe for Mr. Jones the general characteristics of the Queen-Grayburg-San Andres formation in this area?

A. Okay, I'm no geologist, but I'll try to -- this is my interpretation of it.

The -- You've got five radioactive sandstones that are pretty -- and locally when they were developing these reservoirs, they called them the Penrose A, Penrose B, Loco Hills, Premier and Lovington. You've probably heard those names before. And then you've got the San Andres dolomite down below.

The five upper sandstones, the radioactive sandstones, they vary in thickness anywhere from 10 to 20 feet, and they're continuous across the lease, they're probably continuous through most of this area here. They're excellent for waterflooding because you've got tight, impermeable dolomite that separates the sandstones. They are continuous, they're not lenticular. An ideal rock to waterflood. The San Andres is a dolomite. It seems to -- it starts at about 2200 feet, it goes down about 2800.

The NMOCD calls it all the Queen-Grayburg-San Andres. Those shallow sands start about 1400, they go down to about 2000. And then the dolomite, the San Andres dolomite, starts about 2200, 2300, goes down to about 2800. So the gross injection interval is going to be from about 1400 feet down to 2800, 2900 feet.

Q. The sands are continuous across --

A. Yes, sir, yeah, they're -- these --

Q. -- the areal --

A. -- they're not lenticular. That's what makes them an excellent candidate to flood, because they're continuous.

Q. Is this an expansion of an existing project?

A. Yes, sir, an expansion of SWD-988.

Q. And a copy of that saltwater disposal order 988 is included in our material as BP Exhibit Number 3; is that right?

A. Yes, sir, it is. This is it right here.

Q. Let's go back to Exhibit Number 2. Would you go to page 11 and just identify that, please?

A. Oh, yeah, this is -- as required by the

Application, this is a lease map that identifies all the leasehold operators in wells within two miles of the proposed injection project, the waterflood project, and we've got highlighted the Section 33.

Now I made a mistake when I was putting this together. The circles are two-mile diameter, one-mile radius, and it should have been one-half-mile radius.

Q. But the area of review is correctly set forth on Exhibit Number 1, is it not?

A. But this is it, yeah, this is -- this is what we've provided. This is what the State required, and this is what we're providing for clarity purposes. This shows all the wells within the two-mile -- within two miles of any proposed injection well, all wells that ever penetrated the proposed injection interval, and it also shows the leasehold operators of these wells.

So all the information that the C-10- -- that the NMOCD requires is on this map here. This was just one that -- this part of the Application, it sounded like this is what I needed to do.

Q. But if you're really trying to read this map, it's much better to refer to what we've offered today as Exhibit Number --

A. I think this is probably the -- yeah, the best map to refer to.

Q. Okay. In this Exhibit Number 2, pages 12 to 24, are some tables that contain well data. Does this table set forth all information required for each well within the areas of review, as required by OCD Form C-108?

A. Yes, sir.

Q. And also it shows plugged and abandoned wells?

A. This -- The well data table does not show plugged and abandoned wells, we have a separate data table for P-and-A'd wells.

Q. And at this point in time I think it's important that we point out to the Examiner that there are actually four wells where there is inadequate information on the efforts to previously plug and abandon those wells, and we will address those separately later in the testimony.

In Exhibit 2, do pages 25 through 30 contain well data sheets for each of the proposed injection wells?

A. Yeah, this has got all the information on the well as it is currently.

Q. And then --

A. And then also the proposed -- the condition of the well, the packer setting depth, the injection tubing, the proposed perfs. In some cases it's existing perfs, in some cases we're going to add some perforations. All the producing formations are not perforated in each one of these wells, so you've got the before and after.

Q. And that's shown for each of the proposed injection wells?

A. Yes, sir.

Q. What's set forth in pages 31 through 47 of this exhibit?

A. Let's see here. 31 through 47 is the P-and-A schematics for the 37 wells -- There's 37 wells that have been P-and-A'd actually in the initial area of review, and I can't tell you right now if we've lost a couple of those or not, but these were all -- There was 37 in that initial slightly larger area of review. This is the schematics for all those wells.

Q. Have you reviewed all data on all the wells within the area of review for this proposed waterflood and satisfied yourself there's no remedial work required on any of these to enable BP to safely operate this project?

A. Yes, sir.

Q. That's with the exception of those four wells we're going to address --

A. Right --

Q. -- in a few minutes?

A. -- the four wells with the missing data that --

Q. Why don't we go to page 48 of this exhibit, and I'd ask you to identify what that shows.

A. Okay, 48 is a table -- These are wells that we didn't catch -- well, actually I caught them in the *Dwight's* database, PI database, and these are actually five wells that I submitted -- I think I talked to Mr. Jones about this, about -- to submit this information, and this is some information we got on *Dwight's*. And in a few of the wells there was a little bit of information in the NMOCD database, but we couldn't tell if it was a real well or not, but we thought we'd better submit it as part of the application.

Q. And what we have here is, we've identified five wells, correct?

A. Yes, in the initial application we identified five wells.

Q. And for each of these wells you have not been able to locate sufficient information to establish how, in fact, the wells have been plugged and abandoned?

A. That's correct.

Q. Now when were these wells drilled, approximately?

A. These wells were all drilled in the 1920s.

Q. And has BP been on the location for each of these wells, trying to locate the wellbore?

A. Yes, we've sent field operators with GPS devices, gave them the legal location, to go out and scout these locations to see what kind of -- if there was P-and-A markers or any kind of archaeological evidence to suggest there was some kind of cable-tool drilling activity in these locations.

Q. Mr. Hargrove, I'd like to look at these wells one at a time with you.

A. Okay.

Q. I'd like to start with the Tigner State, which is the third well on this list. Is that well an issue in this case?

A. Tigner State. No, the Tigner State dropped out when we modified our injection pattern, so that's one well that actually dropped out of the area of review. So it wasn't --

Q. Okay, what about the --

A. For purposes of this Application, it's not within the area of review.

Q. What about the Workman Thompson Number 1 well, the fourth well on the list?

A. Yeah, the Thompson Number 1 is actually located closer to SDX Resources. This well is located .48 miles from our Washington 33 State Number 23 well. It's about .3 -- it's about -- it's .48 miles from our Washington 33 State Number 23, and it's .35 miles from SDX Resources' Northwest Artesia Unit Number 15, so --

Q. So it would have had to have been in an area of review for the -- for that well --

A. I think so, yeah --

Q. -- is that right?

A. -- when the application on the C-108 for the Number 15, we assume this well was probably addressed during that application, but it's right at the -- it's .48 miles from our well, and it's actually .34 miles from the Number 15. We've actually got -- We've actually got a Queen-Grayburg-San Andres producer between our proposed injection well and this well that we're not even, you know, for certain that it exists.

Q. It was drilled when? Do you know, approximately?

A. This well was spudded in June of 1925.

Q. And how much --

A. Well, let me back off that. This is -- you're talking about the -- the Thompson

Q. -- the Thompson --

A. -- the Thompson, yeah, I'm sorry, June, 1925.

Q. And how much information is there on this well?

A. We've got -- there was a little bit of -- there was some data in the NMOCD database. When we say some, there was an API number registered and just not a whole lot of information there. Most of the data we got was from the PI *Dwight's* database. We've got well location, we've got casing size, we've got some setting depths, no cement, we've got a TD, and we've got the original operator that drilled the well, we've got an API number. So this is -- that's what we've got.

Q. What about the Delhi State Number 1 well?

A. Okay, the Delhi State Number 1 well is located 990 from the south, 1570 from the west, up in Section 28, and it is --

Q. When you were on the surface, were you able to find any actual physical evidence of this well?

A. Okay, yeah, we -- the field operator didn't find anything, no P-and-A marker, no dry- -- no P-and-A marker, no -- apparently with these cable-tool rigs there's some archaeological evidence of an old drill site. He couldn't find anything to suggest that there had ever even been a well drilled there on this well.

Q. And how far is it from the nearest injector?

A. It's .46 miles northwest of our Number 4.

Q. What about the Bixby Fry State Number 1?

A. Okay, and also there was -- on this Delhi State Number 1, if it's okay?

Q. Uh-huh.

A. -- there was no data in the NMOCD database on this well. And so our operator couldn't find any evidence, there was no data in the database.

We picked up some data -- location, casing, TD -- from the PI *Dwight's* database, and that's why we included it in this Application.

Q. What about the Bixby Fry State Number 1?

A. Bixby Fry State 1 is located in Section 4. Okay, this well is -- there wasn't any data on this well in the NMOCD database because we picked it up in *Dwight's*. The operator found what, quote, could be a cable-tool drilling site. No P-and-A marker, no -- you know, nothing like that. No wellhead, obviously no P-and-A marker. It's about .4 miles south of our Number 23, so it's -- I don't have it picked here, but it's .4 miles south of our Number 23.

There is good -- There is a Queen-Grayburg-San Andres producer located between our Number 23 and this well that we're not too sure exists.

Q. Finally, what about the Welch EP State Number 1?

A. Welch EP State 1 is up in Section 27, which is northeast of Section 33. This well is located .34 miles northeast of our Number 2 proposed injection well. There was some data in the NMOCD database, but -- I don't have it in front of me, but it's like very -- just very, very little, like a few sheets, nothing -- no P-and-A information, probably, no drilling information or anything like that.

We actually found what could have been a cable-tool drilling site on that well, and no wellhead, no

P-and-A marker, and this is a well that we've actually got -- we've got to produce or -- directly between this well that we're not too sure exists and our proposed injection well, so it's outside of the proposed waterflood area.

Q. Mr. Hargrove, in fact, we have four wells --

A. There's -- yeah --

Q. --in this category; isn't that right?

A. Well, four wells that are within this area of review that we just were not too sure if there's a well there, that we picked up some data.

Q. And isn't it fair to say that each of these wells are outside of the waterflood project area?

A. Right, they're outside of the waterflood project area, we've got Queen-Grayburg-San Andres Producers between our proposed injection wells and this -- and this well, these four wells that we're talking about.

Q. Have you contacted the District Office concerning these wells?

A. Yeah, I've had a couple of conversations with Gerry Guye with the Artesia District Office. We're going to try to work together and compare notes to see what information he has as far as if these wells -- Maybe he has some P-and-A information. He's the field rep inspector, I believe, for the Artesia District, Gerry --

Q. Is it -- Is it your recommendation that any order that would approve this waterflood project require BP to work with the District Office of the Oil Conservation Division to assure that there is no concern about the potential of any of these four wells in terms of contaminating water or becoming a vehicle to let injected fluids get out of zone?

A. That's how we'd like to approach this, yes, we'd like to work with the District Office.

Q. What injection volumes is BP proposing?

A. Well, we think before we actually fill up this reservoir, we're going to inject about 2000 -- based on the permeabilities and the thicknesses of the reservoir, doing some basic injectivity calculations, we're thinking about 2000 barrels a day.

Q. And after fill-up, what will be the injection rate?

A. We think once we get the reservoir pressure back up to around bubble point, around 1200 p.s.i., 1300 p.s.i., with our -- we're going to inject about 500 barrels of water per day.

Q. What is the source of the water you're proposing to inject?

A. The source of the water is from the Empire-Abo Unit, we've actually got a waterline from a disposal facility over in the Empire-Abo Unit, over to our

Washington 33 State tank battery facility -- now it's kind of a slash-water-injection-facility. We've got produced water from the Washington 33 State.

And there's another lease, we take water from SDX Resources. I need to look at this Application. We take some water from SDX Resources. If you'll excuse me... Their northwest Artesia unit, we actually take some water -- that water gets combined at the Washington 33 State tank battery.

So we've got three sources of water: SDX Resources northwest Artesia unit, the Washington 33 State Lease and then the Empire-Abo Unit.

Q. Do you use fresh water for makeup --

A. No --

Q. -- in this project?

A. -- no, no fresh water.

Q. Have you run water analyses to ensure there are no compatibility problems with the --

A. Right, and it's included in the Application, we've done analysis on the mixtures of the water, the water at the Washington 33 State tank battery, the Empire-Abo Unit water, scale analysis, we've done the -- you know, which you'd want to do if you're going to put the lease waterflood in -- we've done the scale analysis, and there's no compatibility issues. We're going to have -- we'll have a little scale-inhibition program, a little chemical injection there at the water injection facility, but there's no compatibility issues. There's no prospect or potential to damage the reservoir, and -- you know, there shouldn't be anything like that.

Q. What injection pressure is BP proposing to use?

A. We'd like to start out at the .2 p.s.i. per foot, to the top depth. And once we -- that should be sufficient to -- we should get -- you know, we expect to get 2000 barrels of water per day, or quite a bit of rate, because you're so under pressure in this reservoir, you've got nice permeability.

And once we get -- we start bumping that pressure and we fill this thing up, we get the -- we start pressuring up the reservoir, and we would like to go out there and do a step rate test to see if we could actually increase the injection pressure.

But for initially, we would just need the .2 p.s.i. per foot, which seems to --

Q. If you need to go above .2 pound per foot of depth to the top of the injection horizon, will you contact the Division and be certain that the step rate tests are witnessed; is that --

A. Right, we'd do a step rate test to determine what the parting pressure is, to make -- based on the results of

STEVEN T. BRENNER, CCR
(505) 989-9317

the step rate test, to see if we could get an increase in the allowable on the injection pressure, to get to -- you know, just for injection operations.

Q. How is BP going to monitor the wells to ensure wellbore integrity?

A. We'll have a pressure gauge on the annulus.

Q. And will you fill the annular space with a fluid?

A. Yeah, it would be an inert fluid, sure.

Q. In other words, you're going to comply with the Federal Underground Injection Control program --

A. Right, and do the mechanical integrity tests as required by the State.

Q. In your opinion, will the proposed injection in these wells pose any threat to any source of underground drinking water?

A. No.

Q. What are the -- Are there freshwater zones in the area?

A. There's the Ogallala aquifer, and it goes from about 250 down to 400 feet.

Q. And there's nothing below -- no freshwater zones below the injection horizon?

A. No.

Q. Are there freshwater wells within a mile of any of these injection wells?

A. We've got one freshwater well that we know of -- Let me see here. It's the Depco Road water well, and we've got -- on this application we've got -- I just hand-wrote on the top of it, it's the water analysis from that freshwater well.

Q. And that's page 9 of Exhibit 2?

A. Page 9, yes.

Q. Have we confirmed with the New Mexico State Engineer's Office that this is the only water well in the area?

A. Yes, we have.

Q. We also in this exhibit have included a water analysis for what we call the Empire-Abo Unit waterline?

A. Yes.

Q. That is not a well; is that right?

A. It's a waterline, right, it's not -- it doesn't -- it's just a waterline that --

Q. For some reason it was included in the Application for the Number 12?

A. Still trying to find out who did that.

Q. And you -- And it was included for that reason; is that right?

A. Yeah, it was included because it was a source of fresh water.

Q. Let's go to pages 9 and 10 of this Exhibit 2.

A. Okay.

Q. And would you just identify those for us?

A. Nine and 10 is the net water analysis report, where the -- Page 9 is the water analysis for the Depco Road water well. That's the single freshwater well, and this has all been confirmed with the --

Q. -- State Engineer.

A. -- okay, the State Engineer. This is a water analysis of that particular well.

And page 10 is the water analysis for the water coming from the Empire-Abo Unit freshwater line.

Q. Mr. Hargrove, you've examined the available geologic and engineering data on this reservoir, have you not?

A. That's correct.

Q. As a result of that examination, have you found any evidence of open faults or other hydrologic connections between an injection interval and any underground source of drinking water?

A. No, this is not a naturally fractured reservoir, water is not going to go through a fracture up into the fresh water or any other hydrocarbon-bearing zones above and below the Queen-Grayburg-San Andres.

Q. Oil Conservation Division Rules require that notice of an injection application be provided to all offset operators within a half mile of each proposed injection well and that the owners of the surface land on which the injection well is located. Does Exhibit Number 2 set out the names of all offset operators?

A. Yeah, we -- there was -- we identified 10 leasehold operators that operated properties within the area of review, and two -- of course the State of New Mexico Land Office, and then Bogle Limited, which I think is a ranching outfit. We sent them a copy of the Application also.

Q. And they actually have a surface lease; is that right?

A. I believe so, yes.

Q. And the names of the offset operators are set forth on pages 51 and 54; is that correct?

A. Yes, that's correct.

Q. Now, have you seen the e-mail that was sent to the Division from Jackie Brewer concerning this Application?

A. I read over yesterday, yes, about their -- they've got the Sandlott Number 1 down here in the northwest northwest quarter of Section 4?

Q. Right.

A. Yeah, let me --

Q. Has BP previously responded to Mr. Brewer

concerning his concerns with our project?
A. Yeah, I've talked to him and --
Q. Have other --
A. -- let me get my notes --
Q. -- BP employees also contacted him and discussed this situation with him?
A. Yes, I've talked to him, we've got a landman that's talked to him. The name of the well is the Daugherty Number 1.
Q. Mr. Brewer proposed the sale of this property to BP, did he not?
A. Yes, he did. He's interested in selling it for, I believe, $400,000, is --
Q. And -- and what really is the going rate in this area?
A. About $160,000 for a 40-acre -- for a 40-acre lease with some drilling potential. I mean, not just throwing out a number, more like $160,000.
Q. So more than two times the current going rate is what Mr. Brewer is asking --
A. Yeah, yeah, it was quite a bit. This well makes one barrels [*sic*] a day, it's --
Q. When was it drilled?
A. Let's see here. Back in 1970, I believe, earlier -- Let me get my -- I'm going to have to get the well data.

Okay, the Daugherty State Number 1 was drilled back in actually 1941, production -- yeah, back in February, 1941.

Q. And when did it first produce?

A. Well, I've got production data back to 1970, so I don't...

Q. In fact, it has been producing for a long period of time?

A. Yeah, it's been producing since 1970. I don't have in front of me any -- I assume it probably produced before 1970, but...

Q. Do you know how many individuals have operated the well since 1985?

A. I believe four or five.

Q. And do you know what the current production rate is?

A. It makes about a barrel a day. It's on a timer.

Q. Do you have an opinion on whether or not BP's proposed waterflood project will be able to damage the Brewer well?

A. No, in my opinion our waterflood is not going to have any impact on this well.

Q. And why is that?

A. Well, part of it is analogy. You've got the SDX Resources Northwest Artesia Unit Number 15, which is located approximately the same distance from this well, updip, over in the southeast southeast quarter section. This well has injected a half a million barrels of oil -- of water, as part of this waterflood, and this well has never received any kind of waterflood response from that.

And there's actually no Queen-Grayburg-San Andres production wells between this -- between this Sandlott well and this proposed injection well. So by analogy, we've actually got -- we're going to have Queen-Grayburg-San Andres production wells between our proposed injection well and this Sandlott well.

So not only do we -- I mean, this well has injected a half million barrels of water, this well has never received any kind of response. And this well is completed in an open-hole interval that includes the injection interval for the Number 15 well. We're proposing to convert the Number 23 to injection. We have five Queen-Grayburg-San Andres Unit wells that surround the Number 23, including two in between this well and the Number 23.

And, you know, based on my experience, field development projects, waterfloods and some -- and common sense, honestly, I don't see any way we're going to impact this well.

Q. Mr. Hargrove, have you reviewed the data on the wellbore on the -- on Mr. Brewer's wellbore?

A. Yes, I have.
Q. Any problem with the wellbore?
A. No. This rock is very stable. There's -- I don't see any chance to collapse the --
Q. Is Mr. Brewer's well outside the project area?
A. It's outside the project area.
Q. How are you going to manage this project? I mean, you're going to be injecting in seven injection wells, correct?
A. Yeah, we've got seven injection wells, 22 production wells, and --
Q. If we do the production wells between the injection wells and Mr. Brewer's well, are you going to keep them pumped off?
A. Yeah, we're going to keep them pumped -- we're going to keep them pumped off. We --
Q. In fact, that would create pressure sinks at those wellbores, will it not?
A. That's true.
Q. And so the injection fluids not only are going to be moving toward wells between Mr. Brewer's well and the injection well, but there are going to be pressure sinks around those wells to catch the injection fluid; isn't that right?
A. Right. The way we're going to manage this flood

is, we've got an injection well here, we've got our two Queen-Grayburg-San Andres production wells. Yeah, we --

Q. And by managing the reservoir in this way, in fact, it's not just for Mr. Brewer's well, it's for BP's objective of keeping injected water on the lease --

A. That's correct, yeah.

Q. -- isn't that right?

A. That's just good reservoir management.

Q. And when you do that, you're not posing a risk to an offset well like Mr. Brewer's --

A. No.

Q. -- isn't that correct?

You've identified, I think, for Mr. Jones, the owner, the surface owner, being the State of New Mexico?

A. That's correct.

Q. And Bogle Farms is the only other interest owner, and they just have a grazing lease; is that right?

A. On the surface, yeah.

Q. Have you reviewed your plans for this waterflood with the State Land Office?

A. That's correct, yeah.

Q. And have any objections been expressed by the State Land Office to what you're proposing?

A. No.

Q. Are affidavits confirming that notice of the original application and the addendum herein have been provided to all interest owners pursuant to Division Rules -- are these affidavits included in Exhibit 2?

A. Yes.

Q. And they're on pages 49 through 58?

A. That's true.

Q. Do we have Federal Express confirmations --

A. Yes, we have, yeah --

Q. -- showing that --

A. -- we've got --

Q. -- were received?

A. -- for our tracking numbers, confirmations that these --

MR. CARR: Mr. Jones --

THE WITNESS: -- that these --

MR. CARR: -- we did not put those in the exhibit packet, but we can provide those if you desire.

EXAMINER JONES: As long as you have a --

MR. CARR: We have a --

EXAMINER JONES: -- testimony that you've done it.

THE WITNESS: Yeah.

MR. CARR: We have them, and we can confirm with -- Mr. Hargrove's testimony that we do have them and we will keep them if there's ever a question concerning --

THE WITNESS: For the original application and the addendum, we've got --

EXAMINER JONES: And the addendum.

Q. (By Mr. Carr) Is BP America Production Company Exhibit Number 4 an affidavit confirming that notice of this Application has been published in a newspaper of general circulation in Eddy County, New Mexico, as required by Division Rules?

A. Yes.

Q. Will approval of this Application and the implementation of the proposed waterflood project be in the best interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. How soon does BP desire to commence operations on this waterflood project?

A. We'll start as soon as we get approval.

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

A. They were prepared by me, and I can testify to their accuracy.

MR. CARR: May it please the Examiner, at this time we'd move the admission into evidence of BP Exhibits 1 through 4.

EXAMINER JONES: BP Exhibits 1 through 4 will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Mr. Hargrove, and I pass the witness for questions.

EXAMINER JONES: Thank you, Mr. Carr.

EXAMINATION

BY EXAMINER JONES:

Q. Mr. Hargrove, I just have a bunch of questions written down, maybe kind of back and forth on some of these, but these are existing injection -- existing wells you're going to convert, they're not new-drilled injection wells, right?

A. That's right, they're existing production wells, they average about four to five barrels of oil per day.

Q. You chose to convert existing wells rather than drill new wells, because these are relatively new wells; is that correct? Or the pattern fits?

A. We think that the -- yeah, we've got sufficient well penetration in this reservoir that we didn't need to drill any -- make any additional penetrations. We could utilize these existing seven wells for water injection and effectively flood the Queen-Grayburg-San Andres with these seven wells.

Q. Okay, what spacing will the well be on, and what spacing will the patterns be on? Are these fivespot patterns?

A. Yeah, they -- Well, it's not a perfect normal fivespot, but we tried to create a tight pattern -- Let me see my map here. These are kind of an inverted fivespot, I would describe it.

Q. Okay. Okay --

A. And with what we have -- this is a small -- this is a small lease, so you're kind of -- if it was a larger lease, you know, you could be a little more uniform. But it's -- I think it's a nice -- it's an inverted fivespot pattern, should be able to effectively flood the reservoir with these seven wells.

Q. Okay. I guess speaking of the reservoir itself, you've got this dolomite on the bottom, and then you've got the five sandstones above it.

A. That's right.

Q. Are you going to start out with the dolomite and do the sands later, or are you going to do --

A. We're going to flood it all at one time. We're going to -- we've fleshed out a reservoir management approach. I think it's a work in progress, but we're going to do some reservoir monitoring, see where our injection water is going. We're going to do -- we're going to try to find out where our water is going, see where we're -- once we get waterflood response, see where the -- you know, which zones are being effectively flooded. And then if you've got a thief zone or one zone that doesn't look like it's being flooded efficiently, we'll make -- we'll do some remedial work.

But I think initially -- well, initially we're going to set the packer within 100 feet of the top zone and go in there and pressure up this reservoir and then just do some monitoring, see what -- All these zones have been flooded in the surrounding lease waterflood, so we believe that they can be flooded on this lease too.

Q. So you are -- the BP engineers and you have studied surrounding waterfloods in this same --

A. Yeah, right, we use part of the justification for the project was analogies, field analogies.

Q. Okay. Well, which of these intervals would be the best --

A. Well, yes, it's -- it's --

Q. -- as far as --

A. -- yeah, you know, it depends, the -- like the Lovington in some areas is thicker, and there's some variations on the isopach. The Premier is a pretty nice reservoir, the Penrose A is nice.

The Loco Hills is a little bit thinner, it's more of a 10-foot zone. It might be your least prolific reservoir, but it is continuous. You have 10 feet of pay there, you've got a nice oil saturation, you've got a gassy reservoir. So it's worth flooding, it's continuous.

The San Andres has got more net pay, so it probably has the greatest potential for waterflooding.

But all five of the shallower sands, the 1400- to 2000-foot, are continuous, they're -- you've got good zone -- you should have good zone isolation out there in the rock, in the rock strata, and we expect that this is going to be an effective flood, I think in all six zones, six zones.

Q. Are the gravities the same in all of these -- oil gravities in all of these --

A. Only information we've got, it's all around 34 degrees API, yeah. You've got -- It's fairly gassy crude, too, which makes it good for waterflood.

Q. But the bubble point was 1200; is that right?

A. The --

Q. Original pressure was 1200 --

A. Yeah, but the original pressure out here, if you had to -- I mean, it might be a little bit more than that down in the San Andres, just because, you know, it's a little more -- higher, the deeper you go into the rock sequence.

But if I had to say an average initial reservoir pressure, it was probably around 1200 p.s.i., which is probably around bubble point. You should be around 600 p.s.i. right now. It's well below bubble point, you don't have a whole lot reservoir energy. Luckily, it's a fairly gaseous crude, so even though you're below bubble point you've got some drive just with that gas breaking out.

But from a reserves recovery perspective, you don't want too much of that gas to break out, you want to get it back in the oil, displace it. But you always get it -- you'll get it eventually, but once that gas blows off it's going to be harder to recover this oil.

Q. Okay. Will this ever be a CO_2 candidate?

A. I would never say never. I guess that would depend on oil prices and what kind of -- you know, you might get 20 percent of initial oil in place, 20, 25 percent, depending on how the waterflood goes. I'm not -- Boy, that's a tough question. It could be, yeah. I mean, I mean, I would never say that if oil prices stay where they are and keep going up, I mean, there might be CO_2 potential.

Q. So initial -- so primary, ultimate primary, will be how much oil in place?

A. Ultimate primary should be about 120- -- or 1,150,000 barrels of oil, and that includes about 250,000 barrels of oil that was produced from this 600 acres, from the Queen-Grayburg-San Andres, before ARCO drilled it in 1998.

And the total production from the Queen-Grayburg-San Andres is around 9- -- almost 1 million barrels of oil and 2 BCF of gas.

Q. Okay.

A. We think we can go in there with a secondary recovery -- you're only going to get about 150,000 barrels of oil now at this 120 barrels a day, it's declining 10, 15 percent. So even with the high oil prices you can --

Q. Did you -- Did you do a pore volume calculation? In other words, what would be your ultimate primary as a percent of original oil in place?

A. I think ultimate primary is going to be about 7 percent of --

Q. Seven -- and up to 25 with -- 20 to 25?

A. I'm not sure it would go that high. Let's go 20, I think you could get 20 percent --

Q. Twenty, Okay.

A. -- recovery, yeah.

Q. Okay, so that's -- You're expecting to get more than -- from secondary recovery than you got -- as a percentage, than you got from --

A. Right. A lot of that is, you're going in -- This field was developed, you know -- You're right, I think with secondary we're going to get one -- one to two times primary on this project. The oil is sitting there, the oil is there. You've probably produced 7 -- I don't know, you -- 7, 8 percent of your original oil in place on primary. You might ultimately get 10 if you keep producing this thing for a long time. But with a secondary recovery project I think you can get your 7, 8 percent you've got now, maybe up to 20 percent, at least.

Q. Okay, this -- I guess it will get more attention when it's -- usually when it's a waterflood for workovers and things like that, so maybe you'll do some more stimulation on the --

A. Yeah --

Q. -- producing --

A. -- some of the -- yeah, there's a remedial to really get this. Some of these wells are not completed in all the producing horizons, actually, so we've got some remedial work in some of the production wells, and actually some of the injection wells. We have to go in there, and -- and that's a pretty high skin, when you have casing --

Q. Yeah.

A. -- it's hard to go in there and perforate and fracture stimulate and complete the -- some of the injection wells for injectivity and some of the production wells so all the zones will be open in each of the injection wells and each of the production wells. We'll go in there and start -- if we get the approval, get the gas back in the oil.

And we think that the peak production should be anywhere from 400 to 500 barrels a day, once we start filling up that reservoir, and these things are going to -- you know, we expect something like that, and then -- you know, and probably maybe a 10- or 15-percent decline.

Q. How long will it take to reach the peak, do you think?

A. Two, three -- two years.

Q. So mainly it's -- you're using analogy here. You didn't do a model or --

A. I did use a CGM model, which is a reservoir flood model, to calculate -- determine fill-up. And then beyond that I built a spreadsheet model --

Q. Oh.

A. -- because you have water injection coming -- you have to use different injection wells. You've got production wells, and you've got -- with the CGM model I was able to predict and model the advancing waterflood front --

Q. Oh.

A. -- and so once you had a waterflood response, I built a spreadsheet model. And I layered in -- you've got your primary coming from maybe one direction, and then all of a sudden you've got a secondary hit, so I built kind of a layered spreadsheet model --

Q. Right.

A. -- so it was kind of a hybrid approach.

Q. Okay.

A. And then we -- to justify the project, we took that forecast, and we actually risked it. We brought it -- you know, we risked it and brought it back down to around a million barrels of oil. And I think at the minimum you're going to get a million -- million barrels with this project. And you've got some -- I think some pretty good upside too.

Q. Okay. Are we calling this a waterflood, not a pressure maintenance project, then, right?

A. I call it a waterflood.

Q. A waterflood, okay. The -- Your pressure that you want to put on the wells, what would be the optimum pressure? I know what you said about the pressure limit, but what would you --

A. I'd go -- I would go with the .2 -- I'd go with the -- you know, the .2 per foot. And then once this thing starts filling up and you start seeing some pressure at the surface, do a step rate.

Common sense, I'd drop a couple hundred pounds below what -- you know, you don't want to fracture that thing, we don't want to fracture it. We don't want to open up that rock and have that injection water going in some other zone. Even though you don't have a lot of perm, maybe, in these zones, I think you're better off just -- it's easier on our equipment at the surface, keep our water into the reservoir, and I would say -- I'd say 100 or 200 pounds below your fracture pressure --

Q. Okay.

A. -- would make sense to me.

Q. Well, what would you do -- would you say to a production foreman that if you go out there and you do some injection surveys and you find out that some of your zones are cycling water through pretty fast and almost basically fracturing, and the others are not taking any fluid, what are you going to tell them?

A. Like you have one zone that's already maybe flooded out a -- one of your production wells, or increasing -- I mean, what...

You go in there, the permeabilities don't vary a whole lot in these zones. Actually, surprisingly, the perms -- the San Andres is a lower perm, but you've got a lot more net pay. I would go in there and look at -- maybe you've got scale damage, and that's part of reservoir monitoring.

But if you've got one deep zone that's highly permeable, you might go in and acidize the other zones and see if you can do a stimulation. And you can always go in with some valves and mandrels downhole -- it's expensive -- but do an economics and see if it's worth it, and go in there and put some downhole flow control valves and isolate these zones with downhole packers so that you can actually control and monitor them in a water injected -- Let's say the Lovington is taking, you know, its -- more than its -- the lion's share of the water, and we don't want it -- we want it to take 20 or 15 percent of the injection water, and it's taking 40 percent. Then we'd go in there probably with a downhole completion and choke it back so that it doesn't take as much water.

And we've actually -- to justify the project we actually built almost a million dollars in capital, assuming that we may have to do that, just from a risk perspective, say we may have to go in there once we fill up this reservoir, and we're monitoring the injection into these wells, and also the production wells, to maybe go back in and do some -- install some downhole flow-control equipment.

Q. Does BP have basically engineers as production foremen, or do they -- In other words, is an engineer going to be shepherding this project from the start, pretty much, or is it going to be turned over to production --

A. There'll be --

Q. -- foremen that are watching their costs more than they're watching their --

A. Yeah, actually, in -- part of the reservoir management program is, we've got an engineer now dedicated to developing the reservoir management strategy, and there will be one reservoir engineer in the Houston office that -- I mean, we'll take this data, injection data, production data, and you'll have a reservoir monitoring -- ongoing reservoir monitoring program. And then they're going to communicate the results of that program and changes that need to be made out in the field to, you know, increase injection. And I actually have not been working on that as much.

Q. Are you going to use a monitor well here, or just do production profiles, injection profiles?

A. Well, they'll be monitoring the injection rates and the pressures in each of the injection wells, and also --

Q. But no downhole monitoring of different zones or anything like that, in one well or --

A. There'll be -- no, they'll be downhole, they'll be --

Q. Okay.

A. Yeah, Dodie Hecker -- Dodie is the -- she developed the reservoir management program --

Q. That's great.

A. -- and applications and communication with the field and everything. So yeah, there's going to be --

Q. Sounds like you --

A. -- ongoing, yeah.

Q. Sounds like you do have a concern about the different intervals and monitoring them.

A. Yeah, you've got this many zones -- If you have one or two, you may not be worried -- as worried. But we've got five -- we've got six good zones that really need to take water, and they're all excellent candidates for waterfloods, so we want to make sure that they each get -- if you get 500 barrels a day, 600 barrels a day, whatever that stabilizes at, we want to make sure that each zone is receiving, you know, the water.

We'll have initially more monitoring, going with spinner surveys and tracer surveys, things like that, to see where the water is going. And then we'll kind of take it as we go and see what we need to do.

Q. Okay. Okay, and I got your testimony about not having any effect on Sandlot Energy's well. They're not here today, so -- you know, you're an expert --

A. Yeah, that's --

Q. -- so I've got your --

A. They -- We looked at their water production, and they -- yeah, we don't see any adverse effect on that -- on that well.

Q. Most of your production wells, are they -- you say a maximum of 400 barrels a day. With water it would be another 400 or so?

A. Well, we would say that -- initially, we're trying to fill this reservoir up. Even if -- we should be able to get, we hope, about 2000 barrels of water per day, because we've got good permeability, you've got a lot of reservoir thickness with all the zones.

So once we fill it up, you're going to -- you're going to start to -- the pressure is going to come up. And as that pressure comes up above -- to the point where we're at our max, then we'll probably want to go in there and do a step rate test and see if we can increase it, not to fracture the reservoir, but to -- you know, we've just got more resistance down there.

Q. Right.

A. And so this is just based on some basic Darcy inflow calculations, based on the total thickness and the average permeability and what we think we could inject it. Like we use 900 p.s.i. or so, just assuming that your fracture pressure was eleven, dropped a couple hundred pounds off of it, we assume that the res pressure is 1200 p.s.i., or --

Q. Okay.

A. -- and then we just did the calculations that way.

Q. Okay. Your -- You didn't say anything about porosity in the different zones and water saturation in different zones, but I think I've got plenty of stuff for my --

A. Yeah, right.

Q. -- use here. And let's see, the EUR tax credit, I didn't see it advertised that way. You don't project oil is going to --

MR. CARR: We're not requesting that.

EXAMINER JONES: -- ever go down below $30 anymore?

MR. CARR: Well, and also we're already injecting, and so there's a question of whether we would qualify since we've already started injection --

EXAMINER JONES: Oh, okay.

MR. CARR: -- and it may take the project out of that.

EXAMINER JONES: Okay.

MR. CARR: In the Number 12.

EXAMINER JONES: Okay. Could be -- Let's see here. I'm sure Chuck Morgan at SDX is glad to give you some of his water.

THE WITNESS: Yeah.

EXAMINER JONES: He's always trying to --

THE WITNESS: Yeah, we're --

EXAMINER JONES: -- sending us disposal applications.

THE WITNESS: Right. He's actually -- he's interested -- I mean, I think they're actually interested in developing their flood a little bit more extensively, based on our success in this Section 33. He's actually indicated that to me --

EXAMINER JONES: Okay.

THE WITNESS: -- the guys at SDX in Midland, Texas.

Q. (By Examiner Jones) Okay. Hm. The area of review -- can you guys send an e-mail -- You've probably got this all on a spreadsheet. Can you send that to me?

A. Sure, yeah. We've got that -- the -- the well data table for --

Q. Yeah --

A. -- all the wells --

Q. -- all those tables.

A. -- in the area?

Q. My e-mail is on my -- on our website.

A. Okay.

EXAMINER JONES: Is that kosher, Cheryl?

MS. O'CONNOR: Do you want him to send it directly to Mr. Jones?

MR. CARR: Mr. Hargrove --

EXAMINER JONES: It would be a duplicate of what's --

THE WITNESS: Uh-huh.

MR. CARR: But it will be easier for you to work with --

EXAMINER JONES: Yeah.

MR. CARR: -- in that format, and we'll be glad to send that to you.

EXAMINER JONES: Yeah.

MR. CARR: We can send it directly to you.

Q. (By Examiner Jones) Oh, speaking of that, these wells -- a lot of them are -- I see several of them to 6000 feet. What were they originally going for?

A. 6000-foot well would have been an Abo well.

Q. Okay.

A. You've got -- you've got some Morrow production out there, you've got Abo, because the Empire-Abo units -- you've got Abo, you've got a little Yeso, spotty Yeso, you've got some -- I mean, you've got some Seven Rivers, and then of course the Queen-Grayburg-San Andres.

Q. So the original target out here in this area was the Abo?

A. Well, you had some -- you had some wells from the 1920s to the Queen-Grayburg-San Andres --

Q. Okay, that's --

A. -- you know. Usually you --

Q. -- that's --

A. -- start kind of shallow and you go down, I think, so I imagine the initial target was probably more shallow.

Q. Okay, that's --

A. Yeah.

Q. The reason I'm asking that is to make sure that this interval you're looking at is -- was a concern when they drilled any wells out there, as far as covering it with cement --

A. Uh-huh, right.

Q. -- for placement of DV tools and things like that.

A. Right.

Q. Okay. Okay, let's see, so Number 2, 4, 10, 16, 23, 18, plus 12 is already approved, so --

A. Right, 12 is approved.

Q. -- seven wells, 22 injection wells -- or production wells.

A. Part of the -- when we amended the application, revised the injection pattern, one benefit of it also is, we tightened up our injection, and we've got -- we've got our production wells that -- basically along the perimeter of the lease. So we -- from a reservoir -- it all came together, really, when Dodie was looking at it from a reservoir management perspective. It just made more sense, and from a water -- from a water injection efficiency perspective it makes so much sense to replace those other three wells with the 4 and the 10 and the 18. And then, you know, we keep our water on our lease, keep the water on the lease and produce the reserves there.

Q. I don't know if this is really pertinent, but is the royalty interest from the State Land Office -- is that uniform all through the holding?

MR. CARR: Yes, it is, it's one lease and the royalty is uniform.

EXAMINER JONES: It's like 1/8 or whatever --

THE WITNESS: Yeah, it's --

EXAMINER JONES: Whatever it is, it's --

MR. CARR: Carr.

EXAMINER JONES: -- uniform?

MR. CARR: Right.

THE WITNESS: Right.

Q. (By Examiner Jones) Okay, if you did -- if this was a bunch of different leases and you had to do a -- participation parameters, which ones would you use?

A. Like a co-op?

Q. Yeah.

A. Which lease --

Q. No, which would you use? Remaining primary at a certain percent? Would you use -- In other words, I'm just --

A. Uh-huh.

Q. -- trying to get at --

A. Yeah.

Q. -- what phases would be --

A. I would probably look at the reserve -- the remaining recoverable reserves after you put in a flood. And as far as if you wanted to divvy up the interests from the adjacent lease, if you expand it into a co-op I would -- that makes sense to me, if you're going to flesh out a co-op unit operating agreement --

Q. Okay.

A. -- yeah.

Q. Okay. The area of review -- one more time, I guess. You drew the bubbles around all these six wells, I guess, for this --

A. Right.

Q. -- current -- And is that outlined, the bubbles around all six that's on this Exhibit Number 1?

A. Exhibit Number 1. Okay, yeah, this is just the -- this is the composite, because we had a lot of circles, just -- it got kind of messy inside the lease with all these circles, so we just had the -- our mapping technician in Houston take out that part. And so when they came in and they started to cross, if you will, she just pulled that out for clarity, because we had a lot of circles. So this is our net area of review, I guess --

Q. Okay.

A. -- and we have wells, obviously, on Number 23, and 18 had -- you know, we had overlapping wells. So we just -- we thought for clarity it would be better to just take out those middle lines, so --

Q. Okay. Did you ever -- Did you ever anticipate converting wells closer to the lease line boundary than these wells that you've got?

A. Initially we did. We had 6 and 8 and 27. But we really felt like from a, you know, reservoir-management, reserve-recovery perspective BP was really better -- we had a better chance for covering these reserves with this tighter pattern. We've got these wells out here on the border.

And also, you know, we're putting -- we're going to be injecting water, I think, to protect the offset operators. We've got -- We've got these wells here that are pressure sinks, like Bill -- Bill referred to them. And so we don't -- We've got a lot better -- do a lot better job of keeping our water -- keeping the pressure on the lease and recovering those -- recovering those reserves with these production wells, and not going over and getting into the Sandlott Number 1, that kind of thing.

Q. The -- I guess what I was getting at is, you didn't do a half-mile beyond the lease boundary in this initial area of review?

A. No, no -- well -- because the area of review is supposed to be from the well itself --

Q. Right.

A. -- we didn't base it on the lease line.

Q. So if in the future you guys send us a proposal to add some injection wells, what we were trying to get away from doing was having to do a rigorous area of review --

A. Yeah.

Q. -- all over again, you know, and so --

A. Yeah.

Q. -- I guess what we'll have to look at then is whether the well is beyond the limits of these wells as far as closer to the lease line --

A. Yeah, we --

Q. -- just have to do --

MR. CARR: You know, and it would be possible to identify those if the --

THE WITNESS: Yeah.

MR. CARR: -- new -- if the area of review for a new injector extends beyond what you could identify --

THE WITNESS: It would --

MR. CARR: -- what is within and what outside the prior review --

EXAMINER JONES: We can make that as a finding.

MR. CARR: -- but it would seem like with each new application, administrative application, you would need to include, if it extends beyond the boundary of this, the full area-of-review information, so you would have that with the application.

EXAMINER JONES: Yeah.

THE WITNESS: Yeah, we could probably separate that, say this is the data table from this application, and this is the new eight or 10 wells that were part of the area of review with this -- with this new application. That's a good question, though. We -- but we had so many wells in the area of review just for this application --

EXAMINER JONES: Yeah.

THE WITNESS: -- yeah, we thought we would just, you know, keep it at this and get this thing in, yeah.

Q. (By Examiner Jones) Can I ask you about the production and the production facilities that you are going to go ahead -- What production facilities are out there now, and what ones are you going to be adding, and how are you going to control the pressures on the wells? Is it going to be a manifold or a wellhead of the well itself? That kind of thing.

A. Okay, and I'm going to tell you everything I know about the -- you know, about that. But there'll be -- my understanding is, on the injection wells there's -- there'll be an injection well panel and like a reservoir-monitoring -- like a SCADA system, if you will. So we'll -- with telemetry. And you'll have an injection -- on the wellhead you'll have a pressure monitor and a rate monitor, and basically you could be monitoring rate and pressure. And there'll be a panel, probably a -- I don't know -- I guess it's probably electrified, actually, it's not a solar panel. And then there'll probably be a central -- that data will be sent to a -- probably a database system.

I don't know as much about the reservoir monitoring, but I can tell you that the rates and the pressures we've monitored at the wellhead, and that that data will be transmitted via satellite, some kind of telecommunication -- some kind of communication system to a database that brings in all that data and slots it into spreadsheet or some kind of access database for the reservoir management.

If a well -- you know, you started scaling up and the pressure went up, there would be, you know, like an alarm-type -- I understand some kind of, you know, alarm system or something, you know, something like that, that triggers it, Hey, this well's got scale damage. There's -- there -- probably be a shutoff. There'll be a valve on these wells, so that if your pressure went above the allowable injection pressure then you shut the well in, I mean, until we go out there and see what -- what's wrong with the well. But -- So the wells will be monitored at the wellhead.

And you're going to have the water injection facility. It will be right there at the Washington 33 State tank battery facility. And it's located just maybe less than a mile southwest of this Number 12. It's in the central part of the lease. That's why the Number 12 was an ideal well to convert initially to water injection. One, it's in the centroid of the lease, if you will, it's right there next to the battery.

So we'll have a -- as far as the production facilities right now, I think you've got a tank battery, you may have a heater treater, separator -- there'll be a heater treater, because you're going to have probably more water to separate your oil and your water. There's water tanks, settling tanks.

And I don't know if the lease is -- I guess it's probably trucked off. I don't think it's a -- it's probably trucked off. But it's just a basic --

Q. Okay.

A. Is that wrong? Okay, I'm --

MR. CARR: I mean, Ms. Hecker is here if you need additional information on this part of your question.

EXAMINER JONES: No, that kind of goes beyond the scope of what you're asking for, so it's just kind of my own...

MR. CARR: Sure.

Q. (By Examiner Jones) I guess I could ask one more thing, is -- The production wells, are they -- what size pumping units, that kind of thing?

A. I think they've got 320s or 456 --

Q. Are they electrified? Is it all electrified out there?

A. Yeah, it's all electrified. You've got a -- you know, you've got -- you've got -- we're going to have probably three triplex plunger pumps, you'll have two pumps working full time once we go -- once we expand, you'll have a backup pump. One of those goes down, you maintain your injection operations with the backup. You'll have, you know, the wellhead monitoring, monitoring at the wellhead. It'll be a pretty basic injection facility right there that's on the grounds at the tank battery facility.

Q. It's probably going to require quite a big of -- re-look from engineers, I guess --

A. Right.

Q. -- to re-do that, but --

A. They've been working on that. I mean, it's -- it got the -- the basics of it now, because we're injecting into the 12, so we've got a -- and then we'll just expand. You've got the footprint, you've got the bases, you'll just expand with the two additional pumps, once we get approval, if we get approval for this project.

(Off the record)

EXAMINER JONES: Okay, I'm sorry, we've just got a -- I think Cheryl has a couple of questions for Mr. Hargrove, and I think for just a second maybe we can --

MR. CARR: We are going to call --

EXAMINER JONES: Okay.

MR. CARR: -- Ms. Hecker to review how they monitor this project.

EXAMINER JONES: Yes, and so we'll finish up with -- and I think we have Mr. Brewer in the back of the room. So Cheryl will say -- what? And you guys can talk about that.

EXAMINATION

BY MS. O'CONNOR:

Q. Yes, I have just a couple of questions. I've listened to your testimony about why you believe that these injection wells are not going to affect Mr. Brewer's well. But because you're in a slightly different location, in the event that you are incorrect and that there is some repercussion to Mr. Brewer's wells, or this one well for Sandlott Energy, what effect would you anticipate there being?

A. From my impression, it would be a positive impact. He's got a source of pressure maintenance to the north, probably going to get -- if anything, if there's any impact at all, it would be, I would suspect, positive. He would receive some type of pressure support right -- from this -- just north of -- you know, north of his well, possibly, and if anything an increase in oil production, is what I would expect.

Q. And you had testified earlier as to what the going economic value was of Sandlott's wells or of the wells in this area, and what are you basing that on?

A. The land person, the landman -- and I'm not involved too much in acquisitions and divestitures right now, that sort of thing, but I believe it was like $160,000 for a 40-acre section. And I could be wrong, but I think

$160,000. And that's based more -- probably more on acreage that has not been drilled.

This acreage has actually been drilled and produced. You know, you had reserves production on this lease. I don't know what mineral interests are owned, I don't know if it's just Queen-Grayburg-San Andres or if it actually goes deeper than that, but that was the number that I was given. So the price that was asked was considerably higher than that. But $160,000, I think, is what Mr. David Lawrence, which is BP's landman, indicated to me.

Q. Okay, so you're just relying solely upon the landman's -- what he has advised you; you have no independent --

A. Yes, we --

Q. -- estimate to use on the value of this --

A. Yeah, I would have to go in and really look at what's -- you know, the remaining reserves, what's remaining there, you know, and how it would even fit with this lease. You know, it's not something we --

Q. So has BP -- is it considering purchasing this well if it was for sale?

A. I think that's correct. I mean, yeah, certainly we would consider it. But I think that's as -- probably as far as I could go. I'm really not qualified to answer that question, to tell you the truth, because I don't work in acquisitions or land, but I think we'd entertain -- I think that we'd listen to a proposal. I think that was as far as it went.

MS. O'CONNOR: That's all the questions that I have.

But before you step down, Mr. Brewer, what would your participation -- what are you anticipating your participation is going to be at this hearing?

MR. BREWER: Just the -- you know, the fact that I'm -- I'm a small producer, and I'm just -- I can't afford the increased water or -- you know, it's just going to -- if I increase that water it's going to mess me up, you know. The well's --

MS. O'CONNOR: Excuse me, I don't want to interrupt you, but why don't we save your statement for later? So what you're anticipating is just to make a statement?

MR. BREWER: Yes, ma'am.

MS. O'CONNOR: Okay.

(Off the record)

EXAMINER JONES: Mr. Carr, do you have any follow-up questions?

MR. CARR: I have no redirect.

EXAMINER JONES: Thanks, Mr. Hargrove --

THE WITNESS: Thank you.

EXAMINER JONES: -- appreciate it. We asked you more questions than probably necessary here.

THE WITNESS: Oh, no, I -- My pleasure.

EXAMINER JONES: Thank you.

THE WITNESS: All right.

MR. CARR: May it please the Examiner, at this time I'd like to call Dodie Hecker. And I think she could testify from where she's sitting, if that's all right with you, for just a couple of questions that are a follow-up on things that were raised in your examination of Mr. Hargrove.

And so with your permission we'd like to call Dodie Hecker and ask that she be sworn.

EXAMINER JONES: Okay, will the witness please stand to be sworn?

(Thereupon, the witness was sworn.)

DODIE HECKER,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Dodie Hecker.

Q. Ms. Hecker, where do you reside?

A. Houston, Texas.
Q. And by whom are you employed?
A. BP America.
Q. And what is your current position with BP America?
A. I'm a reservoir/production engineer for Permian Basin, so I have -- I'm over Corrigan waterflood, Washington waterflood and a couple other properties in the Permian Basin.
Q. Have you previously testified before the Oil Conservation Division?
A. No, I have not.
Q. Could you review your educational background for Mr. Jones?
A. I have a BS in petroleum and natural gas engineering from Penn State University.
Q. And when did you receive your degree?
A. In 2002.
Q. And since that time for whom have you worked?
A. I've worked for ExxonMobil for three years and then BP for the past year.
Q. Are you familiar with the Application filed in this case on behalf of BP?
A. Yes, I am.
Q. And have you been involved in developing the

waterflood proposal that has been presented here today by Mr. Hargrove?

A. I've been involved in the addendum process. I was not involved in the original application.

Q. You, in fact, made recommendations concerning the adjustment that has been made to the injection pattern, did you not?

A. I did.

Q. And your role has been related principally to reservoir-management issues and efficiency issues; is that fair to say?

A. That is.

Q. And Mr. Jones had questions for Mr. Hargrove concerning how BP is going to manage this property to assure that wells are properly operated, and really to assure the water stays on the lease; is that fair to say?

A. That is correct.

Q. Could you explain to Mr. Jones how you intend to accomplish that?

A. We have -- I'm going to go on to two separate things. We have a reservoir-management/surveillance plan which we've met out in the field and gone through, and that's involving -- that's going to involve such things as the surveillance of it, which would be the information-gathering, such as the frequency of production testing, the actual production testing method, the water testing at the producers to watch for chloride changes.

We're going to have dynamometer and fluid levels, and where that's going to actually be accomplished -- which I'll go into what little I know about the surface facilities -- each of our wells have a communication.

So on each of our producers we can manage -- we can actually see real-time what the wells -- like the pump rate, the fluid level, the pressure, backside pressure, and that's actually communicated to a central computer -- I don't know networking very much, but we have a dedicated -- what -- he's called an optimizer, who'll be looking over each of these wells. So it's actually his job to pull up the wells every morning and make sure that the fluid level is at where we want it to be, and make sure that the wells are pumped off properly and make sure the pumps are, you know, not having problems in the lifting process.

And so that -- he would be the person that would say we either need to decrease or increase our pump size or rod, you know, stroke length and all that kind of stuff. And so we have a dedicated person in the field.

And so we've set up a pretty -- I wouldn't say intensive surveillance plan, but we have frequencies, we have concerns, we've set up rules and responsibilities for each of the field people. And as a matter of fact, next week I'm going out to the field to ensure that we have staffing, to ensure that we do this properly, deplete this reservoir properly. And so that's been my role.

And on the injectors also, we do have pressure, and we're actually adding more testing facilities to make sure that we get at least two days of tests on each of our producers. Currently we have two small -- well, one testing production tank, and then we're actually going to be adding another one to ensure that we're testing them at a proper frequency.

And each of our injectors, we will have pressure and -- I don't know about -- if each of them are going to be able to measure rate, but we do have total flows on -- because we're getting water from the Empire-Abo water lines, we have a total flow on that pump to go over here, then we have a total flow on -- and that's going to actually be able to separate because we have another measurement for SDX water, so we're going to know how much SDX water, we're going to know how much Empire-Abo water.

And then we're going to have a total flow on each of the pumps to make -- and then we could do, obviously, a subtraction and figure out how much the Washington is contributing. And so we're going to be able to measure all of our water, and it's going to be primarily at the pump.

And then at each of the pumps we're going to have pressure and shutdowns and pop-valves, whatever is required by State at our injection facilities.

And so each of our injectors we're going to be doing -- our frequency for doing -- we were talking about our conformance profiling. Currently we have it set up that we're going to do an initial conformance profiling, and then once a year -- and the first one is going to be a tracer tap, and then probably the next year is going to be just a temperature survey, and then -- So it's going to be every other year we're going to run a tracer survey to ensure that we're putting the water -- you know, because a tracer survey is a lot more accurate. And so that's our plan currently.

And then we're going to tag the wells and all that kind of stuff, to ensure that our fill is not above the formations.

Q. Ms. Hecker, what you've generally reviewed here is how BP intends to manage this waterflood project?

A. Yes.

Q. And by doing that, is it BP's belief that they will be able to keep producing wells pumped off?

A. Yes.

Q. And by keeping those wells pumped off, is it BP's intention to keep the water that is injected on this lease waterflood?

A. It is for BP and surrounding offset operators. I mean, we have no want to let our water that we're paying for to go into the ground and go off lease.

Q. It makes no sense for BP to operate a pressure maintenance or waterflood project for the benefit of the offsetting tracts?

A. That's exactly correct.

Q. And so to the same extent that Mr. Brewer is concerned about there being an impact on the project -- on his well as a result of your project, you're also concerned that you're not going to be making this investment to benefit offsetting leasehold?

A. That is correct.

Q. And is it your belief that the water you inject will stay on your lease?

A. Yes, I do.

MR. CARR: That concludes my examination of Ms. Hecker.

EXAMINATION

BY EXAMINER JONES:

Q. Ms. Hecker, the SCADA system will send data to -- also to you in Houston; is that right?

A. Currently it's a special program that we don't have -- I could get it if I were to go out to Midland, and I can actually, you know, net conference so I can actually see someone else's screen. But currently the communication does not go into Houston. But we have field engineers in Midland, Texas, that are also involved on this project.

So how BP sort of sets it up is, I do reservoir and make recommendations. The production engineer out in the field, the Midland/Odessa office, is actually the person responsible for carrying out the recommendation. So he would be the person that I would call up and we could conference. But yes.

Q. Okay, yeah, the pressure limit on each one of these wells, even if they're a little bit different on the top perforation, is it -- is it to you all's advantage to have a set pressure limit instead of just a different one for every well?

A. Yes, we would try and make this as simple but as efficient of a process, since this is a new waterflood, and we'd want to make it as efficient.

Q. So whatever we come up with in the relation of .2 p.s.i. per foot, it would be better if it was the same --

A. Correct.

Q. -- over all of them?

A. And we've looked at -- I have a couple spreadsheets on the surrounding waterfloods, and I see what they've asked for in their pressure limits, and we probably -- and we know what formations they're injecting into, so we would perform it as a step rate test and also bound it by what other waterfloods in the area are doing too.

Q. Okay. So right now you've got 320 units on them out there?

A. You know what, I do not know.

Q. That's okay. But you're going to have dynamometers on all the rod strings in the wells, and they're going to go into the SCADA system, and you'll have rates and pressures on the injection wells and --

A. Yes.

Q. -- shutdowns on your injection wells, or at least at the manifold or something, you'll have that?

A. Yes.

Q. Okay. I know you're concerned about keeping the water on the lease, and I understand that you might have a little trouble sometimes with that, but I think we're more concerned with you getting the maximum amount out of secondary recovery that you can get than you are -- totally keeping the water totally contained on this lease, so -- I hope I'm not speaking out of turn here, but that's -- I think we're for prevention of waste and also protection of correlative rights, but the San Andres and the others --

MR. HARGROVE: -- Grayburg --

Q. (By Examiner Jones) -- Queen zones or --

A. -- Grayburg --

Q. If they're a good waterflood candidate on this lease, they may be good right off the lease also. So anyway I thought I'd better say that.

That's pretty much -- I think we've -- Now we can turn it over to Cheryl. Cheryl, do you have a question?

MS. O'CONNOR: I don't.

EXAMINER JONES: I don't have any other questions.

MR. CARR: That concludes our presentation in this case.

EXAMINER JONES: Okay. Thank you, Mr. Carr. Thank you, Ms. Hecker and Mr. Hargrove.

And Mr. Brewer, would you like to stand and make a statement?

MR. BREWER: Yes, sir. My final -- my main concern is, you know, this is a very old --

MS. O'CONNOR: Mr. Brewer, could you introduce yourself for the record, please?

MR. BREWER: Oh, I'm sorry, Jackie Brewer, Sandlott Energy.

But my main concern, it's an old well, it's -- I think it was drilled back in 1948 and, you know, we've got open hole on so much of it. And if it was to get any, you know, water from the flood, we would -- you know, I can't -- I'm a small-time operator, I can't afford, you know --

we all know the cost of pulling units nowadays. This well hasn't been pulled in 16 years, it's been a -- you know, it's just daily, you know, three barrels a day.

Now I have had trouble with pumpjacks, you know, tanks, occasionally, stuff like that. But as far as the downhole, I have no problems at all. And if I was to get water over there to it, you know, it would scale up, it -- corrosion, there'd be all kinds of problems. With hauling the water off, it would be a problem.

You know, I'm sure increased production would help me, but I don't think it would be that much increased compared to what water would be increased.

And I'm just -- you know, I don't want to get in no more bind than what I'm, you know, already presently in with, and trying to prevent that from, you know, getting this -- I mean, I understand their, you know, their plan there, it's -- should it go that far. But then, you know, if we inject water into that, we'd never know what's going to happen, you know. This formation, something could bust loose, and it could -- you know, it could -- the casing, we'd have casing problems, you know, from corrosion, scale, just a number of things, you know.

And I got thinking once, I thought, well, I'll just leave it alone, you know, I shouldn't have to come back. But the more I thought about it, the more I thought, you know, this could be a problem. And, you know, if -- whatever BP decides, if they want to, you know, go in here and, you know, if the water increases, help me out there, you know, we can work something out.

But you know, I haven't had any kind of promising results from going -- anything that they've said hasn't helped me out, you know.

EXAMINER JONES: Mr. Brewer, how much does your well make? Water and oil, right now?

MR. BREWER: It doesn't make any water unless I go under and pump water down there, like with soap or something. But it -- when the well runs pump, you know, maybe eight hours, it'll make three barrels a day when it's running constantly.

And so it's not big well and it's not a big producer, but it is a good well. It doesn't make, really, any water -- well, to speak of, maybe, you know, an inch or two out of the month production. But that's, you know, just condensate, more or less.

EXAMINER JONES: The -- Have you got a pumping unit on it or --

MR. BREWER: Yes, sir.

EXAMINER JONES: -- are you just flowing it?

MR. BREWER: It has a pumping unit.

EXAMINER JONES: And how much does it cost to get rid of your water, if you ever made any water?

MR. BREWER: Well, I'd have to have it hauled off, so I really don't have any -- I know what, you know, the price of hauling water is, it's skyrocketing right now.

EXAMINER JONES: Do you already have a tank there?

MR. BREWER: No, it's not even set up, the separator or -- it's got a water tank sitting there. There's no separator, you know, it's -- just all goes to the oil tank. There's no water to speak of, so there's no need for a separator at this time.

EXAMINER JONES: Yeah. Do you agree with the waterflood concept in this reservoir, that it's been successful in other wells, other waterfloods?

MR. BREWER: I don't understand your question.

EXAMINER JONES: Do you see any beneficial use whatsoever with BP injecting water in their wells?

MR. BREWER: Do I see any benefits for me?

EXAMINER JONES: For you?

MR. BREWER: No, I don't.

EXAMINER JONES: Okay.

MR. BREWER: I see just hazard.

EXAMINER JONES: So you look at it as a hazard -- hazardous --

MR. BREWER: Yes, sir.

EXAMINER JONES: -- potential hazard to your well?

MR. BREWER: Uh-huh.

EXAMINER JONES: Okay. Okay, that's all of my questions. Appreciate you coming up here and making a statement anyway.

Okay, with that we're done. We'll take Case 13,750 under advisement. Thank you all.

MR. CARR: Thank you, Mr. Jones.

EXAMINER JONES: That being the last case on the docket, the docket is --

MR. BREWER: Thank you.

EXAMINER JONES: -- closed.

(Thereupon, these proceedings were concluded at 10:00 a.m.)

* * *

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 ________________ ______.

______________________, 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 August 4th, 2006.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2006