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 BEACH EXPLORATION, INC., TO INCREASE THE MAXIMUM SURFACE INJECTION PRESSURE WITHIN THE WEST HIGH LONESOME (PENROSE SAND) UNIT WATERFLOOD PROJECT, EDDY COUNTY, NEW MEXICO

CASE NO. 13,127

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

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

August 7th, 2003

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 7th, 2003, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

August 7th, 2003
Examiner Hearing
CASE NO. 13,127

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E X H I B I T S

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A P P E A R A N C E S

FOR THE DIVISION:

DAVID K. BROOKS, JR.
Assistant General Counsel
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1220 South St. Francis Drive
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

JAMES G. BRUCE
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P.O. Box 1056
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* * *

ALSO PRESENT:

GAIL MacQUESTEN
Deputy General Counsel
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
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WHEREUPON, the following proceedings were had at 1:55 p.m.:

EXAMINER JONES: Call Case 13,127, Application of Beach Exploration, Incorporated, to increase the maximum surface injection pressure within the West High Lonesome (Penrose Sand) Unit Waterflood Project, Eddy County, New Mexico.

Call for appearances.

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

EXAMINER JONES: Okay, any other appearances?

Will the witness please stand for being sworn in?

(Thereupon, the witness was sworn.)

<u>JACK M. ROSE</u>,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence for the record?

A. Jack Rose, and I live in Midland, Texas.

Q. Who do you work for and in what capacity?

A. I work for Beach Exploration, Incorporated, and I'm a petroleum engineer.

Q. Have you previously testified before the Division as an engineer?

A. I have.

Q. And were your credentials as an expert accepted as a matter of record?

A. They were.

Q. And are you familiar with the engineering matters related to this Application?

A. I am.

MR. BRUCE: Mr. Examiner, I tender Mr. Rose as an expert petroleum engineer.

EXAMINER JONES: Mr. Rose is so qualified.

Q. (By Mr. Bruce) Now, Mr. Rose, this case involves Beach's West High Lonesome (Penrose Sand) Unit. Were you the engineer who testified in this case when the unit was organized a couple, three years ago?

A. I was.

Q. Okay. Could you -- Mr. Examiner, when you look at the first exhibit it's marked Beach Exhibit 22. That is actually Exhibit 22 from the original unitization hearing. I haven't renumbered it.

But Mr. Rose, could you maybe take Exhibit 22 and then the underlying Exhibit 1 and give the Examiner a little history of the unit and orient him with the area and the other waterfloods in the area.

A. Yes, this is just northwest of Loco Hills about six miles, and this is a depleted field that has been depleted since 1991. It's a Penrose member, sand member of the Queen sand, and it produces from about 1750 feet, approximately.

This area on primary production produced about 550,000 barrels of oil. And as we'll see on the next exhibit, there are several other Queen units in the area, Penrose waterfloods that have been successful in this area, and they generally recover an additional 1-to-1 secondary to primary, so we expect to recover another half a million barrels, approximately, a little over.

This was the original proposal that was put forth, and that is the unit outline as it stands today. It consists of 27 wells. The idea was to -- and the sweet spot of this reservoir is up in the northern portion, and we're going to peripheral flood that area. And we have two phases of injection.

The first phase was going to be 13 injectors, which are the darker injectors on this exhibit, and the lighter-colored injectors would be Phase 2. And the idea was to produce those wells until they watered out from the bordering injection wells and then convert them to injection. And probably two-thirds of the reserves are up in that northern portion where you see Well Numbers 5, 4, 3 and 4. And so that's the main area we're interested in.

So that's what we went in with as a plan.

The next exhibit, titled Exhibit Number 1, is an area map depicting the other Queen-Penrose floods in the area. The West High Lonesome Unit is crosshached and so designated with nomenclature also. These all are Queen-Penrose sand-member floods, which is the same thing we're flooding here. They've all been fairly successful in flooding this interval, and some of them are quite a bit older than ours.

And we've just been -- They hired me about three years ago, and we got this flood going and I put it in, and that's why they've been a little bit slow in getting going with this one.

The other significance is that -- when we get into it later is, these other waterfloods have typically injected -- and this was out of testimony at a 1981 hearing on the Red Lake Unit to increase the pressure on that unit. But testimony was given at that hearing that these other floods used surface pressures from 1360 up to 1800 pounds to successfully waterflood these.

Q. And what pressure are you seeking?

A. We're seeking 1100 pounds. 1100 pounds was requested at the original unitization hearing, and we were told at that time that they couldn't grant 1100 pounds but, if we submitted additional data, that they would administratively consider that and probably approve it, because they knew we were going to need more pressure.

Q. Okay, and we'll get into that in a minute. Why don't you move on, then, to the Exhibit 2 and discuss a little bit of the unit performance and when it went on line, et cetera.

A. The -- Before we go to Exhibit 2, the second page on Exhibit 1 is a current status of the existing unit, the only difference being -- between the original plan, is, the Well Number 19, over on the western edge, was originally intended to be an injector, and we ran into a casing leak on that well and spent about $80,000 trying to fix that casing leak, and the OCD finally allowed us to just call it a producer, and we're producing that well rather than injecting.

Again, this shows Phase 1 and Phase 2 injectors. We're still in Phase 1 at this time, which are the solid triangles. The dark triangles on this represent what wells we have step-rate tests on right now, and we may refer back to that at a later point in time.

Q. Okay.

A. Going to the next exhibit, Exhibit Number 2 consists of two pages. The first page is a daily performance of the High Lonesome Unit, and it includes water that we've injected, water that we've produced and oil that we've produced on a daily basis.

The second page is tabular information on the monthly injection pressures and volumes, as well as oil production. And we can refer back and forth to these.

But if we'll go back to the performance plot on the first page, the order to form this unit was issued in October of 2001. We installed the unit from basically May through August of 2002. We got all our work done and started injection on September 4th of 2002, and this is a record of our daily history since that time.

We started out producing in the 35- to 40-barrel-a-day range, which is the heavy black line on the bottom, and we were injecting about 1500 barrels a day.

If you look at the second page, what we're really going to be talking about on this performance history is injection pressure and the problems that we've had.

If you look on the top bar of data, we have dates and then we have the title "Unit, West High Lonesome Summary", and we barrels of water injected and p.s.i. And basically that is the pump pressure at the main pump. We have individual pressures that have been recorded on each well and what volume has gone in during each month to each well.

If you look at the unit summary, you see we started out in September at about 550 pounds, and in

October we moved to 750. We drop down to 350 in the period November, December and January. And then at the end of February we're up at 650, March we're 1000, and then in April, May and June we're in the 800 range, and then in July we're back down to 325.

The authorized pressure is .2 p.s.i. per foot in this -- in the original order, which is about 350 pounds at the plant. When we first installed the unit, we have 13 injectors that we hope to get 200 barrels a day per well in. With the additional conversion of five more wells we're actually talking about a potential of 3600 barrels a day. We designed our injection pump to pump 2400 barrels a day, which is about 72,000 barrels a month, into this flood.

We started out, and in order to keep our pressure down we have to bypass. We couldn't get that much water in the ground, so our bypass -- we couldn't get our bypass lined out, this J-100 Triplex that was reconditioned from another flood that we had. We had some problems with our bypass, and it took us a month and a half to get those bypass problems resolved.

So when we started out, you can see at the beginning of this flood we were injecting at higher pressures, approximately 550 pounds up to 750 in October. And we were injecting on a monthly basis, 40,000 barrels a month, which is still bypassing somewhere around 30,000 a month. We finally got those problems resolved and were able to get our pressure down to the 350 pounds.

And you can see in December our injection dropped down to about 900, 800 barrels a day, which translates to, on the second page, 350 pounds. In November it was 34,000 barrels. It started tightening up on us. In December we got 26,000 in the ground, January we got 22,000, and most of February was actually at 350 pounds and we got in about 20,000 or a little less than 20,000.

This is a tight reservoir. The initial completions have to be frac'd with small frac jobs to get these wells to produce. So we knew from other units in this area it was going to be tight and we were going to run into some pressure problems. So we were rocking along at 350, we weren't putting near the water in the ground that we felt like we needed to.

The original calculations in this flood show a free gas saturation of about 1.6 million barrels, so we have to get 1.6 million barrels in the ground before we see peak response, which we anticipate to be 300 barrels a day, and we're starting at about 35.

The original plan with getting 200 barrels per day per well in here was that we could possibly get that done in 21 months, and we could see a peak response. And the economics were based on a 21-month response to peak. And we see other Queen floods that have done that. Queen is a real permeable, it hits fast and it goes out quick. 150-millidarcy-type sands when you run into it.

So we have a long way to go. To date we've cum'd 363,000 barrels of water in here.

What happened in late February is, our bypass blew out on us again, and we recognized the need to -- You know, we weren't going to be able to continue to do this.

At that time we investigated bypass, found a better option on the bypass and ordered one, but we couldn't get it until early April. So we got up to a high pressure in March, actually late February. Late February is when we filed the administrative application for the pressure to 1100 pounds. I mailed that out on the 15th of February, and I think the records indicate that you all got it March 4th, or started looking at it.

So we again had bypass problems. We got up to as much as 1000 pounds at the unit. 950 was the highest we sought, individual wells.

At the beginning of April we finally got that bypass. Our only two options when that bypass went out was either shut the flood down or inject at higher pressures. And of course we're violating the higher pressure -- the pressure limits that you all gave us, but we really felt like we were still in line with the frac information that we had.

We got that bypass at the beginning of April and put it in, so we were able to bypass again, although we did not lower our pressure in April, and we still ran. We had the application in to you all for about a month at that point in time. Everything we had heard at the original hearing and contact with Mr. Catanach indicated that there probably was no problem with it, so we continued to inject with the idea that we need to get this water in the ground, we're not going to be able to -- So we continued to inject.

What we did do at the beginning of April is, we ran three step-rate tests on selected injection wells to see in the High Lonesome Unit area what kind of frac pressures we were looking at. The three that we ran those step-rate tests from indicated that the lowest one on the surface pressure frac'd at 885 pounds, and the other two frac'd at about 940 to 950 pounds.

So what we did is, we limited our pressure at the plant to 850 to 875, you know, 25 -- in that range, to stay under what we saw as the frac pressure out there, realizing that we were stepping over our bounds by continuing to inject, but we wanted to keep this thing moving.

The other thing we saw, and what you see in the production plot, is that we started to see a response in

April. And we've gone from 35 to 40 barrels a day, up to 75 to 80 barrels a day, again on that heavy curve.

And when the administrative application wasn't approved and we realized there's some concerns and that we need to not be doing this, we shut it down in July, back to 350 pounds. You can see the production is starting to drop at the end of this plot, and right now we're running about 55 to 60 barrels a day in August, early August, which is one bar down from where we are on our oil plot right now.

Q. Now, Exhibit 3 is simply a copy of the administrative application that you filed on this matter; is that correct?

A. Yes, that's correct.

Q. And it was filed, and then in -- what, early or mid-July -- It wasn't denied, but the Division set it for hearing?

A. Yes.

Q. Okay.

A. And we hadn't heard an answer and we were beginning to get concerned, so we decided, well, you know, please give us an answer or let's set it for hearing, and if there are concerns let's issue those and see if we can satisfy you all.

The original application, there are some pieces in there that are significant to our case. You all have had that and you've reviewed it, but there's reference to this 1.6-million-barrel fill-up number that I've talked to. Also, our original 21 months to our peak volume is critical for our economics.

The other fact is that we overspent installation on this unit by a significant amount, primarily because we had to plug two existing wells that were drilled in the 1940s. And then this Number 19 injector, we spent $80,000 trying to convert that to injection and were unable to. So out of an $865,000 AFE, I think we quote in here like $1.3 million.

Q. Are most of the wells in this area relatively old?

A. There are a spattering. Most of them are relatively new and have had some uncirculated to surface on the surface casing and the production casing in generally 4-1/2-inch or 5-1/2-inch casing. Some of the Iles wells which are on the eastern portion of the unit are older. There's about three wells that are in the unit that are probably prior to 1980. Most of these wells were drilled in the 1980s.

Q. Are there any other -- Besides the item 2 on page 2 of this Application, are there any other particular areas that are important to your Application?

A. There are two on -- The fifth page back is a cross-section on the original application, and that is going to be critical to what I speak about for this 1100 pounds.

Q. Okay, should the Examiner keep that in front of him then, the cross-section?

A. Yes, the cross-section will be good. There's also a frac-height log that was included in the original application that's not a copy here. I have a copy of that in the original administrative application here, and I can -- You all have a copy of it, but I can bring it before you and show you what I'm talking about if I need to here. The frac-height log in that cross-section are something we'll need to talk about when we get into the 1100 pounds.

Q. Okay. Well, why don't we move on, then, to the exhibit -- the primary exhibit, Number 4, and discuss the tests you have conducted and why you believe that raising the pressure to this level will cause no adverse effect on any of the other zones.

A. The Red Lake Unit, which is also our unit, was approved to go to 1500 pounds back in 1991 on a hearing, and for that hearing -- I wasn't with Beach at the time, but they did five step-rate tests on Queen-Penrose wells in that unit back in 1991. They also did four injection profiles at 1500 pounds, and they also had a frac-height log run to estimate what kind of frac growth we're talking about if you go over frac pressure.

This original Exhibit Number 1 -- or the Exhibit Number 1 that we're talking about now, has a copy of that cross-section. It shows the cross-section that is in that area, and it also shows what wells we've run step-rate tests, both in the Red Lake back in 1991 and in the High Lonesome today, and it shows which wells we ran injection profiles on and a frac-height log. So that's the -- It kind of gives you an areal distribution of the data that we've got and what kind of area that covers, and it covers a pretty good area of the Queen.

Referring back to Exhibit 4, what we have here is a tabular summary of all the step-rate tests that were run in 1991 on our Red Lake Unit and what we've run this year in the High Lonesome. The High Lonesome has six step-rate tests run. The three without asterisks on them were run in early April after we had our bypass problems, and they were run by ourselves, and we ran charts on those and we have those charts. They were not witnessed by the OCD. Again, we ran those tests to satisfy ourselves what our frac pressure was, you know, where we needed to stay away from.

In response to the hearing and getting additional information, we did step-rate tests in July on three additional wells, and those are the ones with the asterisks on them. And those were witnessed by Phil at the OCD in

Artesia, and he -- we were able to show him our methodology on our step-rate tests and what we'd done back in April and what we were doing now.

Q. So you've conducted step-rate tests on what, about half of the injectors in the unit?

A. Yes, currently we're injecting into 12 wells, and we have current step-rate tests on six of them.

Q. And what does that data show insofar as injecting at 1100 pounds?

A. What we have is a -- If you look at the second page, to give you an -- yes, the second page is an example of the step-rate tests that we've performed, and basically we injected increasing rates and pressures until we see a break in the slope of these lines, and where those two lines intersect is where the formation is parting and frac'ing.

We have three sets of curves on these step-rate tests. The raw data that we took in the field are the circled data and have lines drawn through them. We take surface pressure readings, and of course when you get up to significant rates you have friction drop in the tubing. And so we adjust those surface pressures and subtract friction pressure because the bottomhole is not seeing that friction pressure. We go through a calculation to calculate our surface friction, and we adjust the surface pressure down to the triangle lines, which is an absolute surface pressure that would be seen downhole.

And basically, that pressure where those two intersect is where things frac at the surface. Friction pressure at normal injection rates, even at 500 barrels a day, which -- we're not going to get 500 barrels a day in any of these wells; we're probably lucky to get 150 in. But at 500 barrels a day at 1750 pounds, you've only got six pounds of friction drop. You can see on these we had to get up to rates of 5000 and 6000, and you can see those curves depart from each other as rate increases, which indicates friction.

So we take that initial surface pressure, which is what I'm considering my surface pressure limit, and we add a hydrostatic gradient because we're injecting fresh water, and we calculate a bottomhole frac points, and we draw lines from both of those. So we have a surface friction-adjusted pressure, frac pressure, and we also have a bottomhole frac pressure. We've done that for six wells now, and they're tabulated on that first sheet.

And what we're seeing is the range -- in the West High Lonesome area it ranges from a surface friction adjusted frac pressure of 830 up to 1220 pounds, are our frac points.

And we've also listed frac pressures at the bottomhole and calculated with the mid-perforation depths what the fracture gradient is for each one of these wells. And you can see it ranges from about a .9 up to about a 1.17 frac gradient, which are pretty high frac gradients. Most formations frac at about .7, and that's where you all come up with your .2 p.s.i. per foot. .433 is the normal gradient. Add .2 to that and you get about a .65, so that keeps you under a .7 gradient. And that's why you have the 350. These formations frac at extremely high fracture gradients.

What -- From a technical standpoint and a waterflood success, when we approach a 1 p.s.i. per foot in a fracture situation, what you end up doing is fracturing these things horizontally rather than vertically.

If you look at the -- Almost 50 percent of everything above us is salt, the rest of it's anhydrite, some red beds. If you take 2 grams per cc. salt gradient and 2.7 carbonate and you average that out, you come up with about 1 p.s.i. per foot is the overburden. When these things frac around 1 p.s.i. per foot what you're doing is, you're lifting the overburden, and rather than frac'ing vertically you're frac'ing it like a pancake.

And our concern -- not yours as much -- if we horizontally fracture these things, we're not getting out of zone by any means. Everything is staying in zone. But we're opening up that zone and bypassing oil, and we're not sweeping oil. So the ones that frac at 1 p.s.i. per foot I'm pretty sure are frac'ing horizontally, and in no way, shape or form do I want to go over 1 p.s.i. per foot. I don't want to frac those wells, because we're going to bypass a lot of oil.

So we ran these step-rate tests for two purposes. One is to find out which ones are frac'ing horizontally, which ones are frac'ing vertically, so we know which ones to stay off of.

The ones that are vertical, they frac vertically, and we can move water up and down the wellbore in a vertical fracture if we get out of zone. We ran the frac height log -- and we've got a copy of that if we need to look at it -- back in 1991, which indicates that at 200 p.s.i. over frac pressure, the fracture -- and the rock mechanics that we've got in this zone, it will frac up approximately 35 feet out of zone and down maybe 135 feet.

So at 200 p.s.i. over our frac pressures which we have stipulated here now with our step-rate tests, we're staying within, you know, that interval.

Q. Before you get going on that, let's address the intervals.

A. Okay.

Q. The injection interval, the unitized interval --

or I should say the producing interval in the unit, is the Penrose sand of the Queen formation?

A. That's correct.

Q. And from that interval, about how far is it to the top of the Queen?

A. About 230 feet.

Q. Okay. And then how far is it to the base of the Queen?

A. About 430 feet.

Q. Okay. And then before we get into that, when you're going uphole, there's also above the Queen is the Seven Rivers formation; is that correct?

A. Right.

Q. Is that formation productive?

A. No, not in this area. It's generally wet, is what we find, or tight.

Q. Okay. And then above the Seven Rivers formation is the Yates formation?

A. That's correct.

Q. Is that formation productive in this area?

A. No, it's not. Again, we either run into tight or wet sands. All these units -- Penrose is the first productive member that you run into in this area, in all of these floods, in all of these wells that we've drilled, probably 30 -- well, probably 60 wells out here.

Q. Okay. And then above the Yates are the salt beds; is that correct?
A. Yes, salts, actually.
Q. Okay. So with that background, go into the vertical fractures and discuss whether or not there's any adverse upon the zones in this area, the --
A. And what Jim is referring to again is that cross-section in the original application. What we did there is, in that application we show the top of the Queen, we show the Penrose sand of the Queen, which is what we're actively flooding now, and then we also show the base of the Queen. This was all defined in a Red Lake well in our 1991 hearing for our pressure increase.
The only two wells in the High Lonesome area that have penetrated deep enough to see the base of the Queen are our Number 19 and 26, and those on that original area plot are listed on that cross-section, shows where that cross-section goes, and you can see the correlations we've got there.
And basically, this says 240 feet above the Penrose is the top of the Queen, and 430 feet below the Penrose is the base of the Queen and the beginning of the Grayburg.
There are some porous sands in the Queen. Porous sands in this area show up as a hot gamma-ray. They look

more like a shale than normal logs. So we do have some porous sands in the Queen, none of which are productive.

The only production, other than from surface down to the base of the Queen, about three miles to the northwest there's some very marginal production in three wells in the Premier sand. And the Premier sand is basically this sand at the base of the Queen that you see, that hot gamma-ray spike, and there's some question about whether the Premier sand is a Grayburg sand or whether it's a Queen sand. So basically we have no other productive horizons all the way down to 430 feet below our producing interval.

With that in mind -- and what we're talking about on those vertical limits, the frac-height log that we ran, run by Halliburton, and -- if I may --

EXAMINER JONES: Sure.

THE WITNESS: -- can I come up there?

EXAMINER JONES: It wasn't in the original of this application?

THE WITNESS: It wasn't in the original application. Our copies that we made do not have -- and this was run on the Red Lake Number 23, and again that's shown in our area maps.

And what this depicts is, we've got a zero to 10,000 scale here, from here to here, and this is what they calculated from rock mechanics as our frac pressure, which is a bottomhole of 1500. And these are basically 200-p.s.i. bars, over and above.

EXAMINER JONES: Okay.

THE WITNESS: So from here to here is 200 p.s.i., you can see here. This one is zero to 400, zero to 800. And basically, this represents trying to show how much this frac should grow at 200 p.s.i. over frac.

And we're basically -- Here's the Penrose sand, you get 10, 20, 30 feet above, probably a worst case you might get up -- you know, you've got 100, maybe 100 feet above. And then down we're talking about, you know, 100, maybe 200 feet below.

So if you stay under 200 p.s.i. what this says is, if you go over 200 p.s.i., over frac pressure, you're really unlimited and you can get growth.

So our intention in the 1100 pounds is to, in vertically fractured wells, not the horizontally fractured wells, we want to be able to go up to 200 pounds above frac pressure, knowing we're going to stay in the gross Queen interval and still get water -- more water into the Penrose, because these other zones are not going to take water, is really what we're shooting for.

So that's the frac-height log information.

Q. (By Mr. Bruce) And the frac would stay, then, within the Queen formation?

A. Yes. So our overall strategy -- and if you look at Exhibit 4 again, which is our tabulation of the frac step-rate tests that we've done, the last column on the right is a vertical frac column where we add 200 p.s.i. to the wells that we assume would frac vertically, and we leave the ones that frac horizontally alone, and those would be the pressure limits that we're looking at.

And if you look at those, we have -- The first one is a 1220-pound horizontal-frac-type well. We've got two others that have a .98 gradient, so we don't want to frac those. The others, we've added 200 pounds to the existing, and they're 1030 to 1085. So you can see what we're shooting out of our 1100 pounds.

There are a couple of wells in here, 1100 pounds won't reach frac pressure on them, but they're probably tight anyway, and we're probably not going to get that much in them.

Q. In your opinion is the additional -- or the increase in the pressure necessary to properly produce the unit?

A. Yes, it is. If we stay at 350 pounds, currently we can inject about 600 barrels a day, which is about 18,000 a month. Our pump again is capable of 72,000, which creates a big mechanical problem. But we've injected

360,000; we've got to get to 1.6 million to get a maximum response. And if you divide the difference in those two numbers by 20,000 a month, that's almost five years before we can fill up this reservoir.

The response that we have seen so far is not a response to fill up in the general sweet spot of the reservoir. We're seeing localized response in two or three wells, basically --

Q. What would that -- If you could refer to the Exhibit 22, Mr. Rose, and point out where you've seen the main response --

A. Why don't we go to Exhibit 1 --

Q. Okay, Exhibit 1.

A. -- the second page of Exhibit 1? I think that one is in front of you in the top there. We're injecting into -- in the northeast corner of the flood, that Injector Number 5, that's one of our step-rate test wells, which is shaded. The shaded injectors are the ones that we want to run step rate tests on, and they include our best injector, which is Number 27 down to the south, and our tightest injector, which is Number 25, just to the west of it. So we've included the range of our tightest and our best injectors.

What we're seeing is response in Wells Number 4 and 6 in the northeast to injection in Number 5, and that's primarily because those are very close, very closely spaced. We're also seeing response in Well Number 22, which is kind of in the southern central portion, and there are three very good injectors, 17, 21 and 27, around it, and so I think that's why we're seeing response there.

We've seen no response out of the sweet spot in 8, 9, 10 and 11, and that's the area that we're going to have to fill up 1.6 million barrels in. My estimation is, if we continue to inject, this response that we've seen is probably going to flatten out until we get more water in the ground, and then we'll see a peak response, hopefully up to 300 barrels a day, and that's what our economics are based on.

Q. Okay. And again, you see no harm to any zone below the Queen or above the Queen by increasing the injection pressure?

A. No, I don't.

Q. Finally, Mr. Rose, what is Exhibit 5?

A. Exhibit 5 is a -- the original injection wells, the OCD-approved injection wells on the unitization hearing. There are 18 wells listed there. We have asterisks by the five that are in Phase 2 that have not been converted to injection yet. The double asterisk is by Number 19, which is the one we had casing-leak problems on, and we will not inject into that well until it's either fixed and we can get your approval, or we'll just continue to produce it.

That area of the field is pretty tight, and we probably won't end up spending any more money. We spent $80,000 on that well, and there's not enough oil down there to justify going after that one again, so...

So we're actually asking for a blanket approval for 1100 pounds for all of the injectors that will be utilized on this exhibit, with the knowledge that our intention -- Our intention is not to go above these. If we go out of zone vertically ourselves -- We're paying 22 cents a barrel for fresh water right now. $8000 or $9000 or $10,000 a month is what we're spending on water. If we start frac'ing out of zone and losing water, we're losing money ourselves. And again, the horizontal wells, we definitely don't want to go over frac pressure on those.

So the 1100 gives us the flexibility to be able to monitor that. If we've got a vertically fractured well that we need a couple hundred more pounds to get a little more water in the ground, we'll squeak it up there, depending on how the patterns are performing. But we don't really want to get above that pressure ourselves, otherwise we're wasting our time and money too.

Q. Were Exhibits 1 through 5 prepared by you or under your supervision?

A. They were.

Q. And in your opinion is the granting of Beach's Application in the interests of conservation and the prevention of waste?

A. Yes.

MR. BRUCE: Mr. Examiner, I'd move the admission of Beach's exhibits.

EXAMINER JONES: Beach's exhibits should be admitted to evidence.

EXAMINATION

BY EXAMINER JONES:

Q. Mr. Rose, can you talk a little bit more about the frac-height log that was run in 1991?

A. Yes.

Q. Was that run after a frac job, or --

A. No, it was run as a portion of the 1991 hearing in order to determine what kind of frac growth we're talking about. So it was run for the pressure-increase hearing at Red Lake, which was done in 1991.

The reason we didn't want to run one now is, we're probably talking $12,000, and --

Q. Okay. But it's a -- Can you talk more about the logs. Does it have a tracer, radioactive tracer and --

A. No, actually these frac-height logs are rock mechanics.

Q. Oh, okay, so Poisson's ratio --

A. Right, that's correct, they're Poisson's ratio, and density calculations and rock mechanics, basically, and it's a calculation. So it's a theoretical -- It's not an actual frac that they measured, it's a theoretical growth. It's a design consideration on how far these fracs will grow.

They did, in the 1991 hearing, inject into five wells and did injection profiles with radioactive tracers in five wells, and those are also listed on that are, are shown on this Exhibit Number 1.

Q. Okay.

A. They are -- We ran five tracer surveys on wells that we were injecting at 1500 pounds with tracer surveys.

Q. Oh, 1500.

A. They all showed to be staying within zone, within the Penrose actually.

Q. Okay.

A. So they didn't show any evidence of frac'ing in the near wellbore. What they were looking there is for communication in the casing also, and all five of those profiles showed within five to ten feet of the Penrose sand.

Q. What's the injection withdrawal ratio out there now?

A. Oh, it's pretty small right now -- or it's pretty large right now; we're injecting a fair amount and we're drawing very low. I don't have that exact number --

Q. That's all right, I just -- Is it over 1 or less than 1?

A. Oh, it's over 1 by a large -- We've injected 363,000 barrels, and we've pulled out 32,000 barrels. So that's since -- You know, that's in about a 10- or 11-month period.

Q. So you attribute most of that to just the permeability slowing down the injection?

A. Yes. These are -- The Penrose sands are an evaporate. What controls permeability and porosity is anhydrite and salt. This is a silicate sand that's cemented with salt and anhydrite. This thing pinches out to the northwest on us, and it dips off to the southeast. And the permeability pinchout is probably salt inclusion in the reservoir and limiting our permeability.

Q. So it's not meaning that you're losing water out of zone or even beyond the unit somewhere?

A. No. Again, we've put -- You know, we calculated fill-up volume, to get this thing back to original saturation and fill it up, as 1.6 million barrels, and we've only got 360 in the ground.

Q. Okay.

A. So we've got 1.3 million barrels to go before we even start pressuring up the reservoir.

Q. Okay.

A. Most of this is -- The resistance that we're seeing is permeability and trying to show a lot of water in a tight zone.

Q. So your wells in the middle are not showing a pressure increase either?

A. The producing wells?

Q. Yeah.

A. No, we're not seeing any response in the wells 8, 9, 10 and 11 up in the middle in the sweet spot, we're basically seeing no water breakthrough, no oil response in that area yet, and don't really expect to until we get more water in the ground.

Q. And you're committed to this peripheral-type injection scheme, you're not going to --

A. -- go back to a pattern?

Q. Yeah, move -- convert some of the real -- higher-permeability wells in the center to injection?

A. That's an option. Our Red Lake Unit did not perform as well as we would have liked to. Most of these units get 1-to-1 secondary-to-primary ratio; that one got about a .5-to-1.

And they imposed a standard fivespot on that unit, and looking back on it, what I think is the -- these evaporates, the permeability tends to pool and vary, and you get sweet spots and you get tight spots in the reservoir. And if you -- there may be localized areas where if you don't set your injection up right, you may not get any water into that area, or you might get breakthrough immediately to another well.

So what we did to make this one successful is start out with this peripheral pattern in the north and in the east. We actually have a fivespot pattern in the southwest. That's a very tight area in the southwest --

Q. Yeah, okay.

A. -- and if at a later point in time we're seeing response, we may convert one of the middle wells to injection and create a little bit more of a pattern up in the north.

Q. Okay. You've got the Yates above you, and is it like the Yates in some areas of the southeast that had a lot of nitrogen, high-pressure nitrogen in it originally when it was drilled?

A. No, the only problem we have drilling these wells is setting surface plugs on surface casing, getting surface cement.

When we plugged -- We plugged two wells in here that were drilled in 1939 and 1940 and were -- basically had no casing in them at all. They were just open holes with plugs in them. We drilled those out. We ran casing in those in order to work on them to clean them out, to replug them, and we didn't have any trouble cleaning them out to 1700, 1800 feet and putting plugs in the bottom.

It took us nearly 600, 700 sacks to cement the surface casing. Cement just goes away, it goes away. It will finally frac out of the ground. And when it fracs out of the ground, it balances our plug and we can get a plug to hold. We drilled one well in here as a portion of the unit, and we had problems with our surface casing on that one. We were able to cement them, but it takes a tremendous amount of cement.

And that's probably what ran in -- we ran into that problem on the Number 19 injector that we tried to convert. We had a casing leak at about 60 feet, and we pumped 1200 cubic feet of cement and never could get it. We tried ten different times, specialized Halliburton cements and some regular cements, and weren't ever able to get it. You would think you could go in there and just pump 50 sacks of cement and you'd be done, but -- so...

That's the only problem we've had in the area. And drilling these wells, we don't get any shows out of the Yates or the Seven Rivers or any of the other Queen members.

Q. Is there a little anhydrite layer right around the Yates, between the salt and --

A. Yes, there are some anhydrite layers on top of the Yates. There's a mixture of anhydrite, and generally you get into salt down to about 500 to 550 feet here. Of course you have red bed shallow. You set your casing at around 300 to 400 feet. You're in pure salt from that down to about 550. And 550 down to the Yates, which is -- well, you get a mixture -- a combination of salt and anhydrite alternating and you get anhydrite right on top of the Yates. When you get back down into the Queen you get salt and anhydrite mixed again.

Q. Yeah. Now, the wells that you said are identified as being controlled by horizontal -- or vertical stresses --

A. Uh-huh.

Q. -- are they identified on here anywhere?

A. No, other than the tabulation of the frac. If we pull out Exhibit 1, on the second page, which shows the wells, and this tabulation which is Exhibit 4, the West High Lonesome Number 1, 5, 17, and 25 range from .98 to 1.17 p.s.i. per foot.

Q. And that was discovered on the -- just on water injection, or was that during a frac job or an acid job?

A. No, those were -- we ran step-rate tests.

Q. Okay.

A. I was out there, and we took our injection water and had a chart recorder and recorded pressures and pumped at continuing rate increases and plotted all that data, and that's --

Q. Did you run bottomhole pressures, memory gauges, on this --

A. No, we did not.

Q. You didn't need to because you could see the break?

A. Yes, you could see the break definitely, and we knew we were using fresh water, .433 p.s.i. per foot, Carlsbad freshwater system, Eagle --

Q. Oh, okay, so --

A. -- is what we're using.

Q. -- it looks like you're paying some money for --

A. Yes.

Q. Okay.

A. All these floods have used Carlsbad fresh water because there's no water up here. You can't -- There is no water. That's the other thing, there's very -- intermittent water at 75 feet, a few windmills, but that's about it. There's no aquifer in this area.

Q. Do you have to control your iron and your -- some of your solids in these injections?

A. Not so far, not initially. We are treating for oxygen initially in our injection water. We've seen some calcium sulfate scale and a little bit of iron sulfide to begin with. Mostly it's calcium sulfate scale that we're beginning to truck-treat some of our producers for. We are putting some scale inhibitor in the injection water also, and we have a closed system on our injection.

Q. So a little bit of -- So you back-flowed some wells and you've seen what's in the --

A. Yes, we -- You know, we have good clean water right now. And of course once the water passes -- We're injecting fresh water, and once that water passes through the Queen formation we pick up a lot of salt, and taking water samples on producing wells tells us what kind of front we've got coming through.

Q. Okay. So I don't -- it was set to hearing -- but there's an awful lot of data you have in here already, and -- I guess you wanted to go 200 pounds over what the step-rate tests show?

A. That's correct, on vertically fractured wells.

Q. Okay.

A. Or have the capability to do that, not that -- before you get enough water in the ground -- we're not going to go any higher than we need to, but if we've got a critical pattern and we need to get water in the ground, if it's a vertically fractured well, we want to be capable of moving up to 200 pounds over, as a limit.

EXAMINER JONES: Okay, that's my questions.

Mr. Brooks?

MR. BROOKS: Nothing.

EXAMINER JONES: Okay. Well, thanks very much.

THE WITNESS: Okay.

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

EXAMINER JONES: Okay. With that, Case 13,127 will be taken under advisement.

(Thereupon, these proceedings were concluded at 2:50 p.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 ______________ 19____.

______________________, 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 11th, 2003.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2006