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 EOG RESOURCES, INC., FOR AMENDMENT OF DIVISION ORDER NO. R-11,389 TO AUTHORIZE A PRESSURE MAINTENANCE PROJECT IN THE RED HILLS NORTH UNIT AREA, ESTABLISH PROCEDURES FOR APPROVAL OF ADDITIONAL INJECTION WELLS, AND FOR QUALIFICATION OF THE PROJECT AREA FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE ENHANCED OIL RECOVERY ACT OF NEW MEXICO, LEA COUNTY, NEW MEXICO

CASE NO. 12,843

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

March 21st, 2002

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, March 21st, 2002, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 21st, 2002
Examiner Hearing
CASE NO. 12,843

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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

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By: WILLIAM F. CARR

ALSO PRESENT:

WILL JONES
Engineer, NMOCD
1220 South Saint Francis Drive
Santa Fe, NM 87501

* * *

WHEREUPON, the following proceedings were had at 1:35 p.m.:

EXAMINER STOGNER: This hearing will come to order.

At this time I will call next case, Number 12,843, which is the Application of EOG Resources, Inc., for amendment of Division Order Number R-11,389 to authorize a pressure maintenance project in the Red Hills North Unit Area, establish procedures for approval of additional injection wells, and for qualification of the project area for the recovered oil tax rate pursuant to the Enhanced Oil Recovery Act of New Mexico. This is in Lea County.

At this time I'll 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 EOG Resources, Inc., in this matter, and I have two witnesses.

EXAMINER STOGNER: Any other appearances?

Will the two witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Off the record.

(Off the record)

EXAMINER STOGNER: Okay, resume order.

Mr. Carr?

MR. CARR: Thank you, Mr. Stogner.

PATRICK J. TOWER,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?
A. Patrick J. Tower.
Q. Mr. Tower, by whom are you employed?
A. EOG Resources, Inc.
Q. And where do you reside?
A. Midland, Texas.
Q. What is your position with EOG Resources, Inc.?
A. I'm a project landman.
Q. Mr. Tower, have you previously testified before this Division?
A. Yes.
Q. At the time of that testimony, were your credentials as an expert in petroleum land matters accepted --
A. Yes.
Q. -- and made a matter of record?
A. Yes.
Q. Are you familiar with the Application filed in this case on behalf of EOG Resources, Inc.?

A. Yes, I am.

Q. Are you familiar with the status of the lands in the Red Hills North Unit area and EOG's plans to implement a full-scale pressure maintenance project in this unit --

A. Yes.

Q. -- by the use of horizontal injection wells?

A. Yes, I am.

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

EXAMINER STOGNER: They are.

Q. (By Mr. Carr) Mr. Tower, would you briefly summarize for the Examiner what it is that EOG Resources seeks with this Application?

A. Yes, EOG is seeking amendment of Division Order Number R-11,389, which was dated May 26th of 2000, which approved a one-well pilot pressure maintenance project in the Red Hills North Unit area to authorize the implementation, also a pressure maintenance project utilizing horizontal injection wells to inject produced water and fresh water into the third Bone Springs sand of the Red Hills-Bone Springs Sand Pool.

Also, EOG is seeking to qualify this pressure maintenance project for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act.

Q. When was the Red Hills Unit formed?

A. Effective -- It was approved May 25th of the year 2000.

Q. And that was Order 11,388?

A. Yes, Order R-11,388.

Q. And what was approved at that time?

A. It was approved to -- Pressure maintenance operations were attempted on a pilot project area, pursuant to that order. The initial project involved a vertical injection well and -- to establish pressure maintenance. Those efforts, however, were not successful as we had originally hoped.

And then also part of the reason we're here is, at that hearing we also advised the OCD that we would come back and revisit this when we refile for the entire expanded project after the initial phase.

Q. Let's go to what's been marked EOG Exhibit 1. Would you identify and review that, please?

A. Exhibit 1 is a land plat on Midland Map that identifies, shows the lands in this area. In red is the unit boundary for the Red Hills North Unit that has previously been approved. It shows the offsetting tracts and the area involved in this area, and we'll get into more detail on the wells and so forth later, but it will kind of show you the -- at this point we have one vertical injection well, which was the original pilot well. And we have a total producing wells of -- 42 wells, which we drilled four horizontal producers, and the rest were vertical.

Q. What is the character of the land in the unit area?

A. It is federal and state, with the federal comprising 98 percent of the unit, and state lands approximately 2 percent.

Q. Have you reviewed your plans with the BLM?

A. Yes, we have.

Q. And what response have you received?

A. We've received no objection at this point. They are apprised of it and, to our knowledge, have no objection.

Q. And you talked to them most recently when?

A. This last week, just to verify they had received all the notice and package, and my conversations with Les Babyak at the BLM, and to my knowledge they had no objection, they just didn't state.

Q. Have you reviewed your plans with the New Mexico State Land Office?

A. Yes, we have, we've talked to them and verified they received all the materials subject to the hearing as well.

I talked directly to Pete Martinez, and they advised they had no objection to what we're doing here.

Q. Has notice of this Application been provided in accordance with the Rules of the Division?

A. Yes, they have.

Q. And is a notice affidavit marked Exhibit Number 2 in this case?

A. Yes.

Q. And to whom was notice provided?

A. It was provided to all offsetting leasehold operators within a half mile of the currently proposed horizontal injection well that we're going to get into here in a minute, in this pool, and also to the owners of the surface of the land on which this injector is located.

Q. Is EOG going to call an engineering witness to review the technical aspects of this project?

A. Yes, we are.

Q. Were Exhibits 1 and 2 prepared by you or compiled under your direction?

A. Yes, they were.

MR. CARR: Mr. Stogner, at this time we move the admission into evidence of EOG Exhibits 1 and 2.

EXAMINER STOGNER: Exhibits 1 and 2 will be admitted into evidence.

MR. CARR: And that concludes my examination of Mr. Tower.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Tower, has there been any new people to notify, other than what -- I mean, new people other than you notified back in 2000 during the initial phase of this project?

A. I don't believe so. Another landman handled this at the time when they put the unit together and took it over from me, and now I've got it back since he left with another company.

In going through all this, I don't believe so, other than we have notified Pure -- let's see, Hallwood Petroleum, care of Pure Resources. Pure recently bought the Hallwood properties, and they operate a well that's just within -- just outside the area. We notified them as an offset operator, but they are a partner in this project with us as well, but we did notify them. And the name change there may catch you where originally it was Hallwood, but it's in the process of being -- now it's Pure.

But other than that, it should be the same people.

Q. Okay, and that unit agreement was a voluntary unit?

A. Yes, it was.

Q. Now, how about the State Land Office? They only have two percent, but were they made aware of the project?

A. Yeah. Oh, yes. Oh, yeah, they received all the material you're seeing today, and we have directly talked to them about it, and they have no objections or concerns with what we're doing.

Q. Have they issued -- either the BLM or the Land Office, have they issued a preliminary approval?

A. Well, the actual unit and operating agreement have previously been approved. This project here is just more of a deviation from what we originally planned to do, and Mr. Cate, our petroleum engineer, will get into the whys with all the wells and the tight rock where we're now going to horizontal wells.

So more of it here is just how we're taking a different approach. All of the unit and the geology, that was approved in the original order and approved by the state, and the federal government blessed and issued approval of the unit and all the contracts. So it's already in place. This is just an expansion to go to the full unit. It was a pilot project initially.

And then also the main thing is, some things have changed, which Mr. Cate will get into as far as kind of a material deviation of how we're going to attack this unit at this time from a technical standpoint.

Does that answer your question?

Q. Yeah --

A. I hope it did.

Q. -- all the questions I was answered more was for if there was an establishment of a unit. This is essentially established, or it is established, and what you're --

A. Yes.

Q. -- discussing now, as far as they're concerned, the people involved in the unit, this is more of a proposal or plan of action --

A. Yes --

Q. -- for the next year --

A. -- that is correct, that is correct.

EXAMINER STOGNER: I have no other questions of Mr. Tower. He may be excused.

MR. CARR: Mr. Stogner, at this time we call Randy Cate.

<u>RANDALL S. CATE</u>,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. My name is Randall Cate.
Q. Mr. Cate, where do you reside?
A. I reside in Midland, Texas.
Q. By whom are you employed?
A. EOG Resources.
Q. What is your position with EOG Resources?
A. My title is project reservoir engineer.
Q. Have you previously testified before this Division?
A. Yes, I have.
Q. At the time of that testimony, were your credentials as an expert in petroleum engineering accepted and made a matter of record?
A. Yes, they were.
Q. Are you familiar with the Application filed in this case on behalf of EOG Resources?
A. Yes.
Q. Are you familiar with the Red Hills North Unit area and EOG's plans to implement a full-scale pressure-maintenance project in the unit by using horizontal injection wells?
A. Yes.
Q. And you've made a technical study of the unit?
A. Yes, I have.
Q. Are you prepared to share the results of your

work with Mr. Stogner?

A. Yes.

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

EXAMINER STOGNER: They are.

Q. (By Mr. Carr) Mr. Cate, when did pressure maintenance operations commence in the unit area?

A. We began injecting water into the Red Hills North Unit Number 302 approximately July 1st, 2001. There has not really been a pressure maintenance as such, because the injectivity of the formation was too low.

The well initially took about 250 barrels of water a day. It quickly dropped to under 100 barrels of water per day. It's currently taking 70 barrels of water per day at the approved pressure, surface pressure, 2375 pounds. And that amount of injected water is not enough to offset the 300 barrels a day of equivalent production from the offset wells, and so the low injectivity has been a problem for us.

Q. What's the total cumulative volume injected?

A. Since that time we've had the well on continuously, and it's only -- it was capable of injecting 26,000 barrels of water, and that's about an average of 100 barrels per day.

Q. And the total cumulative oil production to date?

A. That is 6.51 million barrels for the entire unit.
Q. And that predates this pilot waterflood project?
A. Well, that's current. Since July 1st, the entire unit has produced an additional 520,000 barrels, none of which is attributable, though, to the injection.
Q. And so the pilot project was not successful; is that correct?
A. It was not successful, that's correct.
Q. Let's go to -- You were here two years ago, correct, Mr. Cate?
A. Right.
Q. At that time we were talking and asking Division permission to implement a pressure maintenance project.
A. That's right.
Q. And we were looking at that time at vertical injection wells, and some are between 5 and 7 horizontal producing wells?
A. That's correct.
Q. Today you have a very different plan, do you not?
A. That's right.
Q. Let's go to Exhibit Number 3 --
A. Okay.
Q. -- and let's review for the Examiner how it is that you are changing what you were originally approved to do.

A. Okay, Exhibit Number 3 is a map showing the producing and one injection well within the unit. We have the unit boundary outlined in the black dashed line. And it shows our anticipated plan of a horizontal development which would include approximately five to seven additional horizontal producers, and we have already drilled four horizontal producers to date. But with the lack of injectivity in the pilot project that was approved two years ago, the only chance of a successful pressure maintenance in our mind is to use the horizontal wells also now as injectors, and to be drilled specifically for that purpose.

Those injectors, the proposed injectors, are listed -- are shown in blue. And as you can see, there's seven or eight of those that we have plans in a fieldwide waterflood.

The initial well, however, would be the one highlighted in yellow in the north half of the field. It's the RHNU Number 606. And our plan is to drill it for the express purpose of injecting water into the ground in that area of the reservoir, because it is experiencing high GOR right now. And our model, the Eclipse reservoir simulation model that we run, says that even a delay up to a year could cost us 1.9 million barrels in ultimate recovery. So we're under the gun now to get the pressure maintenance --

enough water in the ground to produce that oil.

Q. If we look at this Exhibit Number 3, the proposed horizontal injection well, the one highlighted in yellow, do you anticipate getting from that well a response that would -- could be seen throughout the northern half of the unit?

A. That's correct. If you notice, I've got a -- I'm not sure what that color is, yellow, brown, magenta, whatever it is, through the middle of the unit. And I ran the Eclipse model with only the Red Hill 606 well as an injector and then monitored the predicted response. And I did see response somewhat down in the south half of Section 12, but the primary response was in this north half. I did look at the far north producing well, which is the RHNU 105, and it received a significant response.

And so therefore the lack of response from that single well in the south half is what directed or guided me in putting a Phase I line at the point that we did, which basically cuts east-west between Sections 12, 7 and into Section 8.

Q. And on the left side of the exhibit you have indicated proposed Phases I and II?

A. Yes. And that, of course, will also have its significance for the EOR tax credit.

Q. Okay. And we look at this, and you intend, in addition to the horizontal injector, the Number 606, you're projecting two additional horizontal injection wells in the north half of that unit; is that right?

A. Yes, that is correct.

Q. And then you've got five or six in the southern portion of the unit?

A. That's right also.

Q. The objective here is, instead of doing what you thought you could do with vertical injectors, you're going to have to get large volumes of water across that large face within the reservoir to effectively implement pressure maintenance?

A. That's right. And even the horizontal wells will not take a relatively large volume of water. I do have an exhibit later that will show the predicted injectivity and oil recovery response.

Q. On Exhibit 3 you also have a type log?

A. Yes, I just included that. That was the log that two years ago we used the RHNU 302 that also --

Q. And --

A. -- unitized interval.

Q. And this is the log that identified the unitized interval and the unit itself?

A. That's correct.

Q. Can you give me or provide the Examiner with a general description of the characteristics of the Bone Spring formation in this unit area?

A. Yes, it is a sand, it's the third Bone Springs sand. On average, it's almost 90 feet thick, with an average of 13-percent porosity and a 38-percent water saturation.

Q. In our original hearing, was the continuity of the reservoir across the unit area established?

A. Yes, sir. Yes, it was, and it's a very continuous reservoir within the field.

Q. And your efforts are at a point now where you're ready to immediately go forward with horizontal injection?

A. That's correct.

Q. And you have reviewed already for the Examiner the problems you're having with the increasing GOR and the need to get this project moving as quickly as possible?

A. Yes, the placement of the 606, if you'll notice, it is directly north by 660 feet and parallel to this horizontal producer that we drilled about a year ago, and that's the RHNU 212, shown in green just south of the projected 606, and it currently produces about 350 barrels of oil per day, but its GOR is now up over 5000. It started at roughly 2000 GOR. And the rest of the field averages about a 2500 standard cubic feet per barrel.

And so on the one hand, the producing horizontal was very successful, but it is drawing us down to the point of bubble point and below, as seen by the rising GOR.

Q. Let's go to Exhibit Number 4. Could you identify this?

A. Yes, Exhibit Number 4 is the OCD Form C-108, with attachments for the proposed RHNU 606.

Q. And that's the horizontal injector?

A. Which is the horizontal injector.

Q. And Mr. Cate, you prepared this exhibit?

A. Yes, I did.

Q. On page 1 you've indicated that this is an expansion of an existing project. What did you mean by that?

A. Well, just simply the fact that we have the project approved from the 303, and the expansion is that within this unit and within the approval to inject that we received two years ago -- and that was under our Order Number R-11,389 -- and that in my mind it was an expansion under that same --

Q. That order approved the vertical injector?

A. That's correct.

Q. That has not been successful?

A. That has not been successful.

Q. And you are now getting ready to implement a full-scale pressure maintenance project through horizontal injectors?

A. That is right.

Q. If that's an expansion, that's what you call it, right? That's not --

A. That was my definition. I can be corrected, though.

Q. Let's go to page 3. Would you identify that?

A. Page 3 is the plat as required under part 5 of the C-108 that shows the two-mile radius of all wells around the proposed injection well, and the one-half mile area of review around the injection well.

Q. Behind that on page 4 in tabular form is the information required by Form C-108 on all wells within the area of review; is that correct?

A. That's correct. That would be part 6, and it shows the tabulation of well names and locations. And then we also included beyond that, because there's a lot of data as far as the construction of each of the wells within the area of review and the perforated intervals, et cetera. So we've got the table and the following schematics for the construction and completion of each of the wells.

Q. Now, are those schematics the wellbore diagrams on pages 5 through 21 of Exhibit 4?

A. Yes, 5 through 21. Within there, there is one well on page 21 which was a dry hole drilled to the Bone

Spring, penetrated and then plugged and abandoned.

Q. And the plugging detail is shown on this exhibit?

A. And the plugging detail is shown. The rest of the wells are all producing within that area of review.

Q. And you have schematics in here for the two horizontal wells that are within the area of review as well?

A. Yes, within the area of review we have the RHNU 212, which I mentioned, and then south of that about another half mile is RHNU 211, which is another horizontal producer.

Q. Mr. Cate, let's go to pages 22 and 23 of this exhibit, and I would ask you to, referring to this exhibit, explain to the Examiner how EOG proposes to drill and complete this horizontal injection well.

A. Okay, this well will be completed -- drilled, constructed and completed just as the aforementioned 212 and 211. And we basically set the intermediate strings, two of them, a 13-3/8 and a 9-5/8, down to approximately 5000 feet. And then we'll drill our curve down into the third Bone Springs sand at approximately 12,200 feet.

We case off the curve with 7-inch casing, and then we drill the horizontal lateral and then run a liner, a 4-1/2-inch liner, and tie back into the vertical portion of the hole at approximately 11,800 feet or so.

The completion, then, is like the other wells. We perforate approximately evenly spaced, but depending on our anticipated thicknesses in the -- that we have crossed in the reservoir, we might concentrate the perforations a little tighter for more of the stimulation to go there. Then we'll respond with a saltwater frac to open up the sand above and below, since it is almost 90 feet thick and on average the frac is the way to get vertical communication into the horizontal lateral.

Q. Have you reviewed the data available on each of the wells within the area of review --

A. Yes.

Q. -- for the proposed injector?

A. Yes, I have.

Q. Have you satisfied yourself that no remedial work will be required on any of these wells to make it safe to operate them within close proximity to this injection well?

A. Yes, I have.

Q. What is the source of the water you propose to inject? The source of the water primarily would be produced Bone Spring and Morrow from the Red Hills Unit itself, and the Morrow comes from the Pitchfork Ranch field, which is adjacent to the Red Hills-Bone Spring.

It will be necessary to have makeup water, fresh water, from the Santa Rosa well initially in this project.

Q. You will be using only fresh water as a makeup? You'll use all produced sources first?

A. That's right, all produced sources that we can economically get our hands on right now.

Q. What volumes are you proposing to inject?

A. Well, I'll show this in a little bit, but the initial injection well 606 is anticipated to take 3000 barrels a day of total fluid, but it drops off very rapidly. Within a year it's down to just over 1000 barrels of water per day.

And so we have produced water in the range of 700 barrels per day readily available. So the makeup water initially would require around 2300 barrels per day, dropping to under 300 barrels per day or so, after one year.

Q. Will it be a closed system?

A. It will be a closed system.

Q. You're going to be injecting under pressure?

A. Yes.

Q. And what are the maximum and average pressures that you're requesting?

A. We're requesting a maximum of 3250 pounds surface, with an average injection pressure of 3000 pounds surface.

Q. This is in excess of .2 pound per foot of depth to the top of the injection interval, is it not?

A. Yes, it is.

Q. Would you refer to what has been marked, or what is included in Exhibit 4 on page 26, identify and review that?

A. Okay, this is a step-rate test that we ran on the vertical injector, RHNU Number 302, and it shows the injection pressure versus the injection rate and the corresponding break in the slope, change in the slopes, at the point that the rock is parted.

Q. And what does it tell you? Can you safely inject at 3250 pounds?

A. Yes. Yes, we can. The actual pressure here where they cross is 3265 pounds, but up to that pressure the rock is not parted and we can safely inject.

Q. Are there freshwater zones in the area?

A. There are freshwater zones. The Santa Rosa formation is up at -- behind the intermediate casing at approximately 300 feet. I think you get sands from 100 to 300 feet.

Q. And what is page 27 of Exhibit 4?

A. Page 27 is a comparison of the produced fluids that we propose to inject and the fresh water from the well that we operate from the Santa Rosa, that happens to be on the northeast quarter of Section 13.

Q. And what is page 28? Is that a water analysis of water from that well?

A. Yes, it is. It says northwest quarter. I believe the well is actually in the northeast quarter of Section 13. And it is the only freshwater well within one mile of this area.

Q. Will the injection you're proposing, in your opinion, pose any threat to fresh water or underground sources of drinking water in the area?

A. No, it won't. I believe the construction of all these wells and the future wells will prevent that.

Q. Now, what you've done is, you have presented the C-108 for the first of the horizontal injection wells?

A. That's right, so we would seek to have administrative approval to submit and have approved the future horizontal injectors on an as-needed basis.

Q. So you'll go forward well by well with the C-108s for the subsequent wells?

A. Yes, each of these wells takes three to four months to drill and build the curves and complete, and we'll want to flow back and get the frac fluids out of them and then start our injection and get the facilities.

So it will be about probably three months, if we kept one rig just going out there. Three to four months between each C-108.

Q. How much do these wells cost?

A. Each of these wells is costing us over $3 million right now.

Q. Have you examined the available geologic and engineering data on this area?

A. Yes, I have.

Q. And as a result of that examination, have you seen or found any evidence of open faults or any hydrologic connections between the injection zone and any underground source of drinking water?

A. No, I have not.

Q. Let's go to your Application for the enhanced oil recovery certification. That's Exhibit Number 5. Would you initially just identify that.

A. Yes. And just real quickly, though, I was going to say, the remainder of these pages are simply -- I don't think -- but it's the APD to drill the 606, so we just included that.

Q. And that's the remainder of the exhibit?

A. The pages within the C-108, yes.

Q. All right, what is Exhibit 5?

A. Okay, Exhibit 5 is the Application to qualify the project for the enhanced oil recovery tax rate.

Q. And this Application includes all information required by OCD rules?

A. Yes, it does.

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

A. Capital cost of approximately $33.8 million, and that includes the drilling, the future horizontal injectors and producers, building a pipeline to get more produced water, and the facilities, the injection facilities that will have to be built.

Q. And what are the total project costs?

A. We estimate a total cost, including intangibles and perhaps water cost, of $40 million.

Q. And how much additional production does EOG expect to obtain from this project?

A. My Eclipse simulation model indicates that we could possibly yield another 17 million barrels above the primary 15 million barrels that's anticipated to be produced.

Q. And what happens to the gas production with this pressure maintenance project?

A. Well, the gas will actually go down by 2 BCF because of the higher abandonment pressure that's left in the reservoir. So you actually lose a little bit of gas, but you do make up 17 million barrels of oil, so...

Q. And what is the total value of the additional production?

A. The additional production, total value, is estimated to be $369 million, based on a $22 oil price, over the life of the project.

Q. Have you also taken out the value of the lost gas?

A. Yes, I have, I've deducted the value of the lost gas at a price of $2.50 per MCF. And of course, those values are undiscounted over the entire life of the project, which might be 60 years. I would ask Michael back there not to run to the bank yet.

Q. If the project is economically successful, do you have any opportunity of plans to expand this horizontally into any other area?

A. Well, it is possible. There are a lot of tight reservoirs like this in Texas and New Mexico. Now, we don't see this exact area here, this unit, expanding at this point. But it is possible that we could get this to work in additional reservoirs in the Permian Basin or wherever.

But just as an aside, we have contacted DOE. We're pursuing possible funding there because this reservoir is so tight, .2 millidarcies, the only reason it produces is because it was overpressured, original pressure 9500 pounds. I mean, we've got some concerns to whether it will work and the quality of what it will be.

Q. Behind the letter Application, Exhibit 5, and attached to it, do you have an exhibit which contains information on the producing and on the initial injection well on the unit, correct?

A. Yes, as required by the rule.

Q. And then the last page of this exhibit is a production forecast, is it not?

A. Yes, it is.

Q. Could you review the information on that forecast for Mr. Stogner?

A. Okay, this is required by the rule, and it shows the historical production. I've got barrels of oil per day and MCF per day on the left side, and then the barrels of water per day on the right side. And we've also got a forecasted oil and gas production response based on the injection that can be seen and also the forecasted increase of water production in the field. We've got it out approximately 13 years, like from -- or, excuse me, 11 years from current. But the project life should be sixty years.

Q. What you're here today proposing is significantly different than what you were proposing two years ago?

A. Yes. In fact, the vertical well, it's been determined, cannot be used as injectors, that we do have to go with the horizontal wells on this.

Q. You're seeking certification or qualification of this project and the enhanced oil recovery tax rate, correct?

A. Yes.

Q. And you're seeking the opportunity to implement this and qualify it for the lower tax rate in two phases?

A. Yes. And again, that is based on the potential response that was predicted by my reservoir simulator.

Q. In your opinion, will approval of this Application and the implementation of the proposed pressure maintenance project in the Red Hills North Unit be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. Were Exhibits 3 through 5 prepared by you?

A. Yes.

MR. CARR: Mr. Stogner, at this time we would move the admission into evidence of EOG Resources Exhibits 3 through 5.

EXAMINER STOGNER: Exhibits 3 through 5 will be admitted into evidence at this time. Also, I should have done this earlier, I'm going to take administrative notice of the cases that resulted in Orders Number R-11,389 and 11,388, for the record in this matter.

MR. CARR: Yes, sir. That concludes our direct examination of Mr. Cate.

EXAMINATION

BY EXAMINER STOGNER:

Q. Cate, as far as the initial injector, this Number 606, what is EOG's plans? I mean, it's still somewhat of in a pilot phase, isn't it?

A. Well, we -- I guess you could say so, depending on how you define it. But, you know --

Q. Well, let me define it like this. I mean, you don't have any other horizontal injectors out here, do you?

A. No, we do not.

Q. Okay.

A. This will be the first horizontal injector, that is correct.

Q. So that's what I was leading up. What does EOG plan to do as far as testing, seeing the results, what are you looking for, what will determine if any additional injectors get drilled?

A. Well, much the same as the vertical well. We'll have to see, number one, does the horizontal well take the forecasted amount of water that the model will deem is needed to at least make this an economic venture? And then we'll have to take those numbers and, you know, put them into our model and bring that up to date.

But if the model is correct -- and I will say that the Eclipse model did predict that the vertical well would only take about this amount of water. We were hopeful that we might be surprised on the upside, but with .2 millidarcies, frankly, we're not surprised.

Q. I thought I understood you to say the vertical injector failed.

A. It failed from a pressure maintenance point of view. It will not take enough water to overcome the withdrawals in the offset wells, and so -- I mean, that's my definition of a failure.

Q. Okay. So you didn't say that the model predicted failure?

A. No, I didn't --

Q. That's not what you were saying?

A. -- say that, no.

Q. Okay, just wanted to make sure --

A. We spent money, yeah. I wouldn't even have done that.

Q. Okay, so you've already got the Number 212 well; that's already a horizontal producer?

A. Correct.

Q. So that's going to be your main focus after you get this injector in there. Not only are you going to be looking at the injection, you're going to be looking at the results, I assume?

A. Yes, we will. We should see a GOR collapse and eventually some water break through. But even those vertical wells to the north of the injector should see response also.

Q. And when you say those vertical producers, are you talking about all of them, the Number 10, 208, 102, 603 and 602 and 601?

A. Yes. And of course, you know, the wells closest to the injection will see the first response. But like I say, even the RHNU 105, which is a mile away, will see a benefit just from the water going in, in this area.

Q. Have you determined, if this turns out to be a successful horizontal injector, which would be your second horizontal injector well to be drilled?

A. We would respond to the south, the two wells that you see just due south of the 212. And the plan, of course -- I mean, it's subject to change, a lot of the technology. Can we drill horizontal wells this long? Some of our producers we only made it out 1500 and had shale problems, had to stop. I mean, the second one could be just to fill in the -- if we have to stop short on the 606, we may be coming back to try to fill in that area undrilled.

But to answer your question, we would start moving south, because that area between the two horizontal wells, producers, the 212 and the 211, is where we're seeing the greatest drawdown below bubble point and therefore the highest need for pressure maintenance.

Q. Okay. Now just to make sure I'm clear, I'm referring to Exhibit Number 3. Your horizontal producers and horizontal injectors, the ones that have a green dot associated with them, those are existing wells; is that correct? Producing wells?

A. Yes, the ones with just the dot and no line are current vertical producers.

Q. Producers. And then those -- I call them purple, you called them blue --

A. Okay.

Q. -- that don't have a green dot associated with them, those are your proposed new drills, I would assume?

A. That's right.

Q. Okay.

A. Yes, we will actually re-enter some existing vertical wellbores and drill out some shorter 2000-foot laterals. That's our current plan. So we would convert some other current vertical wells into horizontal injectors.

Q. Okay. Now, I'm looking down there in Section 13, the Number 302 well. That has a purple triangle. What does that --

A. Well, we just -- up in the upper right -- it's just to signify that it's the current injection well in the area.

Q. Okay. That was the one that was approved under R-3389?

A. Yes.

Q. Okay, I'm sorry, I thought the Number 6 was the current injector. What is the status of the 606?

A. It's yet to be drilled. We have filed the APD, and I think 30 days we're expecting the APD.

Q. Okay, I'm getting there now.

Does this map denote all the existing wells out in this area, whether deeper or shallower?

A. No, not -- particularly within the unit, I think there are some shallow dry holes, oh, down in the south part of Section 13 that would not be reflected.

And then there are some deep wells, for instance, the RHNU 601 -- and you'll see the -- since it's in the area of review, you'll see on its schematic that it originally was a deep Morrow gas producer that has now been recompleted into the Bone Springs sand. But all that is tabulated, you know, on that table and the schematics.

Q. And that was leading up, so I need to go -- to show all the wells within the area, I need to go to the area of review map, page 3 of your Exhibit Number 4?

A. Yes, and the C-108s.

Q. That's right.
A. Yes.
Q. And that's the current Midland map depicting the wells?
A. Yes, as far as I know. Pat Tower says it is.
Q. What are some of your oldest wells out there in that area of review? This is a fairly new developed area, isn't it?
A. Yes, the -- One of the deep wells that actually was the discovery for this field, if you go back down into Section 13, the RHNU 301, it was actually an Atoka and Wolfcamp producer back in the 1980s, drilled, I think, 1984. And EOG -- we recompleted that well into the Bone Springs sands at the end of 1992.
And after watching it for a while and seeing that it was actually a commercial discovery, the program ensued. And so the development did start in 1992. Some of the deeper production in the area had been out here, like I say, in the early 1980s.
Q. So relatively speaking, we're going to have 1980s vintage wells and nothing older than that?
A. As far as I know, that's correct.
Q. Okay. So none of the wells within the area of review -- they're all mechanically sound or have been plugged and abandoned in accordance -- that would not allow

any of the injected waters to leave that injected interval?

A. Yes, I believe they are. And then the fresh waters are behind two sets of casing strings, cemented typically to circulate surface on both strings.

Q. Okay. Now, how about -- maybe I'm missing something here -- water wells within the area? Is that page 41 that would indicate that?

A. There was -- I think it says one mile, doesn't it, within -- but we do have the -- there is only one water well in the area, and it is operated by us, and it is a freshwater well that's used for commercial purposes, drilling, when we drill wells, and it's in the northeast quarter of Section 13. I think it's just about 1000 feet from the RHNU 302. So it was pretty close to that one mile, but even if it was outside -- that's the only well that's in this area, and that's why we included its analysis, the water analysis. It's going to be a typical fresh water.

Q. And that water well was also included in the testimony presented two years ago?

A. Yes, it was. Now, it was within the area of review at that time, yes.

Q. Of that well?

A. Same well, yes.

Q. Are there any other freshwater wells, say in the unit area, anticipating additional injectors?

A. The only other freshwater well that we could find is another one that we use up in Section -- I think it's 32, about, oh, one and a half or two miles north of the unit boundary in Section 6, so it would be north and east in the Madera 32, there is one freshwater well.

Again, it was used for commercial purposes, has not been -- I don't even think it's been produced for maybe 10 years. And that's the only other one. I think the next nearest one is one of the ranchers' wells five miles away.

Q. Okay. Exhibit Number 5, your capital costs, additional facilities, let me make this straight, let me get this straight. This is the cost just for the one well, or is this total cost if the whole thing was to break down?

A. That's the total project cost. That would include approximately 12, you know, injectors and producers, the drilling costs and facilities and a water pipeline.

Q. Let's see. So that would be 12 additional horizontal wells, total?

A. Approximately, yes.

Q. At $3 million apiece?

A. Yes.

Q. So some of these million dollars would be just for the cost of the initial dr- -- or -- well, some of them are recompletions, so that would be --

A. That's right, they will be cheap. So on average it might be $2.5 million apiece, for just the drilling and completion costs.

EXAMINATION

BY MR. JONES:

Q. Okay, Mr. Cate, can I just ask you a few questions?

A. Yes.

Q. This permeability of .2 millidarcies, is it a big variation in that?

A. Not a large variation. We've got buildups that have ranged -- and that's effective on an oil buildup -- but from .5 millidardcies down to .1, maybe even .08. But pretty much within that range.

Q. I guess what I'm getting at is the fracturing in the --

A. No, we don't have any evidence of fracturing. It's not a hugely tectonic area. We did cut four full cores out here -- well, we tried; I think we got really one that's actually a full core -- and there wasn't any evidence of natural fractures. There's some microfracturing within certain places, but it's just a very fine-grain sand. The deposition looked like a submarine fan --

Q. Oh.

A. -- it seemed to have, you know, several pulses from whatever source.

Q. So it's a marine sand?

A. Yeah, we think it's a marine fan, and...

Q. Did you run any imaging logs?

A. Yes, as a matter of fact, we did.

Q. Did you continue those logs up above and below your formation of interest?

A. Yes.

Q. Okay.

A. And the shales -- There are some shales and tighter sands up above.

Q. Are there barriers to injection that you can see on those imaging logs above and below -- especially above your injection --

A. Yeah, if you look at this type log right here on Exhibit 3, there is a shale package about 20 or 30 feet above the pay sand, what we call the Z marker, and it shows up as a pretty good shale.

Q. It doesn't show a bunch of fractures in it --

A. No --

Q. -- in your imaging log?

A. -- it sure does not. And then below that is typically a little bit of a -- kind of a carbonaceous

interval. We've run frac-height logs which are a --
Q. Yes.
A. -- sonic look --
Q. Right.
A. -- and based on that, I mean, the net pressures to frac up and out are astronomical. We really believe all our frac jobs have been staying, you know, very close within zone. So I haven't seen any evidence --
Q. Okay, I was just -- the reason I'm getting at that is for future pressure increases on your injection, if you're going to need them. That would be further evidence for that, besides the step-rate tests.
A. Yes. Yeah, the original bottomhole pressure out here was 9500 pounds, which corresponds to about a 4000-pound surface pressure with a full column hydrostatic of water, so...
Q. Is that good caprock?
A. It's pretty good. And so it has come down as we've completed the pressure in the field, as you can see by the data that we just submitted on the 302, and that phenomenon occurs. But even after drawing the pressure in the reservoir down, you know, 50 percent or more, I mean, we only saw an 800-pound drawdown on the parting pressure, you know, from the original. So...
Q. Right. Now, the reason you want to go on your

injection horizontal well, are you going to go on the upper part of the formation? Is that what you're targeting?

A. We typically do, because we can -- we have found out here that the shales -- I mentioned that some of the shales caught us in the southern part. They tend to come up from below. There's a Wolfcamp shale that this third sand sits on, and you can see the shales on the type log.

Q. You want to stay up not only for injection purposes but to stay away from your shales on your drilling costs?

A. That's correct. And we see that Z marker when we're cutting our curve, so we know right where we're at. But like I said, and then the frac-height logs and the net pressures, we run a FRACPRO, and Halliburton does those for us and says that they're going to be well contained, the stimulations are well contained within the zone, especially now that we've drawn the pressure down, even --

Q. Right.

A. -- from original.

Q. Now, the reason you're going the same direction on your injection well as you're going on your producing wells, are you trying to follow the natural horizontal stress?

A. Yes, exactly.

Q. So you're trying to drill with the least possible drilling costs, and your frac go along the wellbore?

A. That's correct. And that is one of the things that the imaging log told us --

Q. Okay.

A. -- was the borehole breakout, and gave us the primary stress direction, exactly.

Q. Okay. Any other similar reservoirs to this that run through this way, as far as pressure maintenance? Do you have any similar --

A. I don't know of any. If you do, I'd like to know --

Q. -- on the Eclipse model, yeah.

A. Some heavy oil up in Canada, or -- What do they call it, taller sands or something?

But it's a real fine-grained sand, and -- so there was some risk that it, you know, may not respond well. But our only chance is the horizontal injectors at this point.

MR. JONES: Right. That's all I have.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. Actually, that leads me up to some additional questions. What is the stimulation techniques you use out here on the vertical producers?

A. They are typically -- Well, they're perforated in approximately the middle of the sand, 30 or 40 feet of perforations, and then a fracture stimulation. They average probably 130,000 gallons of the saltwater, or the water, and then 200,000 pounds of sand.

Q. How about your horizontal injector or your horizontal producers? How do you plan to stimulate those?

A. Well, one of this length -- We can only can only pump enough rate to do -- like a long one like this, which would be almost 700 feet, would require two stages. The RHNU 212 required two stages. We frac'd the toe end first, seven sets of perforations, almost equally spaced. And each stage carries about 400- -- I've listed it in here, but I think it's 400,000 gallons and half a million pounds of sand. It's in that range.

MR. JONES: And no gel?

THE WITNESS: Oh, it is gelled, yes.

MR. JONES: It's 30-pond gel?

THE WITNESS: Yes, it sure is. Yeah, I think it is a 30-pound gel. But yeah, the stimulation is listed on page 25. 400,000 gallons and 500,000 pounds per -- No, I'm sorry, that's for both stages. So each stage is half that.

And so we'll do the toe end first, clean it up and get the treating fluids off the formation, because it is a sand and susceptible to damage. So we try to -- We'll flow them back, and then we set a bridge plug and come in and frac the heel end and clean it up, flow it back, and then we'll knock the bridge plug out and start injecting, would be the plan.

EXAMINER STOGNER: Any other questions? Okay, you may be excused.

THE WITNESS: Thank you.

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

EXAMINER STOGNER: Mr. Carr, I'd like a rough draft --

MR. CARR: Yes, sir.

EXAMINER STOGNER: -- whenever it is convenient with you.

MR. CARR: I'll need a week.

EXAMINER STOGNER: If you need additional time you can contact me.

MR. CARR: I will.

EXAMINER STOGNER: If there's nothing further in Case Number 12,843, then this case will be taken under advisement.

(Thereupon, these proceedings were concluded at 2:40 p.m.)

* * *

12843
March 2002
Oil Conservation Division

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL March 29th, 2002.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002