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:

ORIGINAL

AMENDED APPLICATION OF CONOCOPHILLIPS COMPANY, INC., FOR AMENDMENT OF DIVISION ORDER NO. R-5897 AND SPECIAL RULES FOR THE EAST VACUUM GRAYBURG-SAN ANDRES UNIT PRESSURE MAINTENANCE PROJECT AREA, LEA COUNTY, NEW MEXICO

Case 14775

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REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: WILLIAM V. JONES, Technical Examiner
DAVID K. BROOKS, Legal Examiner

March 29, 2012

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, Technical Examiner, and DAVID K. BROOKS, Legal Examiner, on Thursday, March 29, 2012, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

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APPEARANCES

FOR THE APPLICANT:

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EXAMINER JONES: We'll go back on the record and call Case 14775, amended application of ConocoPhillips Company, Inc., for amendment of Division Order R-5897 and special rules for the East Vacuum Grayburg-San Andres Unit Pressure Maintenance Project Area, in Lea County, New Mexico. Call for appearances.

MR. RANKIN: My name is Adam Rankin, with Holland & Hart in Santa Fe. I'm here on behalf of ConocoPhillips Company, and I've got two witnesses today.

EXAMINER JONES: Any other appearances?

Will the two witnesses stand and state your names?

MS. MNICH: Cheryl Mnich.

MR. NJOKU: Chibuike Njoku.

(Two witnesses were sworn.)

MR. RANKIN: Mr. Examiner, I call my first witness, Ms. Mnich.

CHERYL MNICH

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. For the record, can you please state your name?

A. Cheryl Ann Mnich.

Q. By whom are you employed?

A. ConocoPhillips.

Q. What is your current position?

A. Senior geologist.

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

A. Yes.

Q. Have your credentials as an expert in petroleum geology been accepted as a matter of record?

A. Yes.

Q. What are your current responsibilities for day-to-day operations at the East Vacuum Grayburg-San Andres Unit operated by ConocoPhillips?

A. I provide geologic support to our team for addressing changes in injection and production on a day-to-day basis.

Q. Are you familiar with the application that was filed in this case?

A. Yes.

Q. Have you prepared some exhibits for today?

A. Yes, I have.

MR. RANKIN: Mr. Examiner, I'd like to tender Ms. Mnich as an expert in petroleum geology.

EXAMINER JONES: She is so qualified.

Q. (By Mr. Rankin) Can you briefly state what it is that ConocoPhillips seeks with this application today?

A. We're seeking to amend Rule 11 in Order Number R-5897 that currently requires injection packers to be set within 100 feet of the top perforation. We'd like to amend this for all present and future injection wells, such that the packer can be set as close as reasonably possible to the top perforation as long as it remains within the unitized interval.

And we currently have some injection packers that are already more than 100 feet above the perforations, and we have a number of wells also that will soon be at that depth.

Q. Thank you. Now, just to be clear, ConocoPhillips amended its application to request an increase in pressure injection but you've dismissed that from the case; is that correct?

A. Correct.

Q. Please turn, Ms. Mnich, to what's marked ConocoPhillips Exhibit 1. Would you please review for the Examiners what this shows?

A. Sure. This is a map showing the location of ConocoPhillips' East Vacuum Grayburg-San Andres Unit located in Lea County, New Mexico. The blue outline is our EVGSAU. We are offset to the west by Chevron, who owns and operates the Central Vacuum Unit and Vacuum Grayburg-San Andres Units.

Q. Chevron has recently applied for a very similar application, have they not, where they requested to reset the packer depths for their two units?

A. Yes. And we're requesting the same rule amendment that they applied for and received in Order R-4442-G, where they received a unit-wide amendment to set the injection packer as close as reasonably possible as long as it remains within the unitized interval.

Q. And you're going to provide an overview of the geology of the unit, and the second witness will be testifying as to the engineering issues; correct?

A. Correct.

Q. Please turn to Exhibit Number 2 and review for the Examiner what this shows.

A. Yes. On this exhibit in the lower right corner, it will show a map to orient where the vacuum field is located relative to the New Mexico border in the United States.

Again, the blue outline shows our unit boundary, and each of the blue circles with the line through it represents one injection well. So this shows the distribution of the injection wells throughout the unit, and we have 116 injection wells currently.

And the A to A prime line is the wells that were selected for use in the cross-section to give a representative idea of what the formations look like across the field east/west.

Q. Now turn to Exhibit Number 3, which is, I believe, the cross-section of the unit. Please review for the Examiners the formations and what this cross-section shows.

A. Sure. Again, it's east/west, and this is showing the relative thickness and depths of the formations from surface down. I'll start from the top. From the surface down to about 1,500 to 1,600 feet, are the Santa Rosa and Dewey Lake Formations; the Santa Rosa around 250 to 300 foot depth is where the shallow aquifer groundwater is.

Below the Dewey Lake is the Rustler and Salado, which is in blue here. And it's predominantly halite or salts with some anhydrite and thin sand interbedded.

Below that is Tansill Formation, which is anhydrite and sand.

The Yates sits below that and is predominantly dolomite and sandstones with some anhydrites, as well. Seven Rivers is predominantly dolomite and anhydrite. The Queen is predominantly sandstone and anhydrite.

And then in green here is the Grayburg, which represents the top of our unitized interval, and it's sandstone. And then below that is the San Andres, which is our targeted injection interval. It's a dolomite reservoir.

And also, I've indicated on here by the red bars, this is the top depth of our -- our top perforation depth in these wells. And you'll see that they're commonly right at the top of the San Andres Formation, since that is our target and injection interval.

And there's roughly 250 feet from the top of the unitized interval down to our top perforation, on average.

Q. Thank you, Ms. Mnich. And so in general, the packer settings are within the San Andres Formation or the Grayburg; is that correct?

A. Correct. They're predominantly in the Grayburg, a few in the San Andres.

Q. Under the proposed amendment, the packers will still be set within the Grayburg and San Andres, and that won't change; correct?

A. Correct.

Q. Please briefly describe for the Examiners the geology of the Grayburg Formation.

A. Sure. The Grayburg again is predominantly sandstone, but it is plugged up with anhydrite, very low permeability. It's really tight. And the vacuum, that's non-reservoir. And the higher up you go in the Grayburg, the less permeable it is.

Q. And what's the significance of the low permeability in the Grayburg as far as the unit is concerned?

A. The Grayburg, therefore, acts as a barrier or seal to our injection interval to prevent vertical migration of our injection fluids upwards.

Q. Are any of the formations overlying the unit considered productive of oil and gas?

A. The Yates is productive at Vacuum Field in small amounts, and yeah, just the Yates.

Q. And are there any other formations that contain salt or carsts or potash?

A. Again, the Rustler and Salado is predominantly the salt section.

Q. Has ConocoPhillips seen any evidence of contamination of injection fluids in any of the overlying formations?

A. No, we have not.

Q. Thank you, Ms. Mnich. Now, turning to notice, can you please turn to what's marked as Exhibit Number 4? Is this a copy of the affidavit prepared by your attorney indicating that ConocoPhillips has filed the prescribed notice requirements under the Division rules?

A. Yes, it is.

Q. Turning the page, is this a list of the operators who were notified of this application?

A. Yes, it is.

Q. How did ConocoPhillips determine who to notify, who the operators were that were notified?

A. We notified all operators within a half mile of the unit boundary.

Q. On the next page, is that a copy of the letter that was sent to all operators within a half mile of the unit boundary?

A. Yes.

Q. And turning the page again, are these the green cards that were received demonstrating that all operators received actual notice?

A. Yes.

Q. Turning to Exhibit 5, is this a copy of the legal ad that ran in the paper notifying of the application and the affidavit of publication?

A. Yes.

Q. Ms. Mnich, were Exhibit Numbers 1 through 5 prepared by you or under your supervision?

A. Yes.

MR. RANKIN: Mr. Examiner, I'd like to tender for admission Exhibits 1 through 5.

EXAMINER JONES: Exhibits 1 through 5 are admitted.

(Exhibits 1 through 5 were admitted.)

MR. RANKIN: I pass the witness.

EXAMINATION

BY EXAMINER JONES:

Q. So the top of the Grayburg is the top of the unitized interval?

A. Correct.

Q. So it coincides with the top of the pool, is that correct, the Vacuum Grayburg-San Andres pool?

A. Correct.

Q. And the bottom of the unitized interval, is it still 800 feet below sea level out there?

A. I would have to double check. But I think it comes out closer to around minus 1,000 feet subsea.

Q. 1,000 subsea?

A. Yes, I believe. I can double check and get back with that.

Q. Okay. I think that it was 800 on the Central Vacuum and the Vacuum Grayburg for years, and then they lowered it because the East Vacuum Grayburg was lower than 800.

A. I think ours was lower, from what I remember.

Q. You're down in the transition zone?

A. Yes, we are.

Q. How is that working out?

A. It's going. We started getting some good tests finally, so 50, 60 barrels a day.

Q. Okay. So the top perfs, you're comfortable staying within the unitized interval just reasonably -- whatever is reasonable above it.

How old are these injection wells?

A. Some of them date back to the 1930s.

Q. So Phillips didn't drill all new injection wells when they put this project in?

A. No. There are wells that were drilled in the '70s and '80s. I'm not actually sure how many are of what vintage. We could go back and find that and provide that information.

Q. That's okay. I'll talk to the engineer about it.

A. Okay.

Q. If you do set your packer up in the Grayburg, it won't affect your water flood at all if you get casing leaks in the Grayburg below your packer? Will it affect your sweep of the San Andres if you have some issues with your casing below your packers?

A. I don't think so.

Q. Because of the --

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A. Because we're not going to lose any fluids into the Grayburg, essentially. There's nowhere for it to go in the Grayburg.
Q. It's too tight?
A. It's too tight.
Q. It's not being produced in the Grayburg?
A. No.
Q. And is it true that you're dismissing the other part of this application?
A. Correct.
Q. Why was that?
A. We needed some more time to get our data together, and we'll be seeking that at a later date.
Q. Okay.
A. We needed to get this taken care of a little more soon.
Q. As far as finding representative wells to do step rate tests, you can talk to us about that in the process?
A. Yes.
Q. You know, your engineer and yourself would know which ones are representative?
A. I believe we received word that any well that we wanted to change the pressure on, we would have to get a step rate test for each individual well.

Q. Okay.

A. So we've been trying to select the ones that are most important to us to get that changed.

Q. Okay. You can listen to your attorney on a lot of this, because what we tell you and what you're going to apply at a hearing -- you can always apply for something.

A. I don't know.

Q. If you can show a reasonable representative sample across the unit --

A. Okay.

EXAMINER JONES: We can talk about that later. But go with what your attorney advises you.

I don't have any more questions. Thank you very much for coming.

MR. RANKIN: I have nothing further for Ms. Mnich.

EXAMINER BROOKS: No questions.

MR. RANKIN: We'll call our next witness, Mr. Chibuike Njoku.

I'm going to call you by your first name, if that's okay, so I don't trip up on my pronunciation.

THE WITNESS: That's good.

CHIBUIKE NJOKU

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. State your name your full name for the record?

A. Chibuike Njoku.

Q. Just a reminder that you're under oath.

By whom are you employed?

A. ConocoPhillips Company.

Q. What is your current position with ConocoPhillips?

A. Production engineer for the vacuum field.

Q. Have you previously testified before Oil Conservation Division?

A. No.

Q. Can you please review your educational background and work experience for the Division?

A. Sure. I graduated from Texas A&M University in petroleum engineering in 2008. Before that, I had two internships in the Permian Basin and Gulf of Mexico shell waters. And since coming to ConocoPhillips -- I worked for South Texas Assets in Alaska, and for the last two years, I've been working the vacuum field as a production engineer.

Q. What are your day-to-day responsibilities working in the unit?

A. My day-to-day responsibilities are being in charge of the basin development, downhole well work projects in the vacuum field and also production surveillance and optimization of our wells in the vacuum field and looking for more ways to increase production.

Q. Are you familiar with the application that was filed in this case?

A. Yes, I am.

MR. RANKIN: Mr. Examiner, I'd like to tender Mr. Njoku as an expert in production engineering.

EXAMINER JONES: He's so qualified.

MR. RANKIN: Thank you.

Q. (By Mr. Rankin) Chibuike, what are the current well completion requirements for the injection wells in the unit that ConocoPhillips has to comply with?

A. Current requirements are that packer has to be within 100 feet of the uppermost perforation. That's the first.

Next, is that the tubing must be protected with some kind of coating. And then the last one is the casing must be --

THE COURT REPORTER: Can you speak up?

A. The packer has to be within 100 feet from the top uppermost interval. And the second is that the tubing must be protected with some kind of coating. And the third and final requirement is that the casing and tubing annulus must be filled with an inert fluid and a surface gauge be used to measure pressure.

Q. Does ConocoPhillips currently operate injection wells within the unit with packers that are currently set above the hundred-foot limit?

A. Yes. We have a total of 116 injection wells in the East Vacuum Unit. And of those 116 wells, we have about 17 wells that are currently injecting with the packers above 100 feet.

Q. There are currently, as I understand, 10 wells, is that correct, that have been shut in because they're not in compliance with the rule?

A. Correct. We looked at -- over the last couple of years, we've had to do workovers on wells, and we found 10 wells which we were not able to get a good packer seat within 100 feet of the top perf. So we had to shut those wells in per requirements of the OCD. And we did extensive research on all wells in the unit areas that haven't been touched in a long time, and we found 17 wells that are not in compliance, for a total of 27 wells, injection wells, that are above 100 feet.

Q. In addition to those 27 wells that are above the hundred-foot limit, there are a number of other wells that are approaching that hundred-foot limit; correct?

A. Correct. We have 34 of the 116 wells that are within 75 to 100 feet of the -- the packer sits between 75 to 100 feet of the top perforation.

Q. Mr. Njoku, can you please briefly explain why it is that the packers have to be reset at a higher level periodically?

A. Sure. This field, to give just a quick background, was discovered in the late '30s, and a lot of these wells have been in service for a long time.

And to your question, we have a mix of wells. We have injection wells -- about a half of our injection wells were converted from production to injection, and new injection wells were drilled in the '80s. So we have a mix of very old injection wells and new injection wells.

The requirements as to what remediation we do when we find a leak is, per OCD rules, we have to do Bradenhead testing once a year and MITs every five years.

So we get a list from the Division district office in Hobbs that gives us what wells we're going to perform MITs on. And based on those tests, those that fail are put on a list to be worked over. And when we work them over, we have to pull the packers up in order to get a test, an adequate test.

Q. How many wells roughly does ConocoPhillips have to do remedial work on an annual basis?

A. Based on our current failure rate and amount of wells, we work on about 12 injection wells a year. Of those 12 wells -- to give an example, that is a mix of cleanouts, MIT problems and also Bradenhead issues. We have three wells that failed this year. We have an inspection period that runs between February and March, and it has already been done for the year for the whole vacuum field. And three of those 12 wells failed this year.

Q. Once you identify wells that have issues, what's the procedure for resetting the packer?

A. When we identify the wells, we write up a procedure to go and work on the well. Then when we do that, we rig up, clean up the wellbore and try and get a good casing packer seat, a good test.

That involves moving the packer to a position where we can get an adequate test. And we have to -- the packers average about three to eight feet long. If you take the higher side of eight feet, we have to move up eight feet every time to try and get a good test. And if we're near collar, that involves going an extra eight feet, so about 16 feet to get a good packer seat.

Q. The reason we have to move the packers up is because over time, these wellbores get corroded and there's natural pitting that occurs and, therefore, the seal is not good below, so you have to go up; is that correct?

A. Correct. Like I mentioned before, we have a mix of very old wells and relatively new wells. So due to mechanical well life, corrosion and pitting becomes an issue over time. ConocoPhillips' procedure on a new injection well, either conversion or a new drill, is to start from 50 feet above the top perf. And over time, we've had to raise the packers up in order to get an adequate test and be in compliance.

Q. Now, this is a problem that ConocoPhillips perceives as a unit-wide issue? You've got 116 injection wells. Approximately 27 are not in compliance, and a number of others are nearing noncompliance?

A. Correct.

Q. So it's something that you perceive as a unit-wide problem?

A. Correct. If you combine the 27 and the 34 wells, we have about 50 percent of our injection wells that are either not complying or nearing noncompliance at this point.

Q. And do you perceive this issue to be something that's very important to ConocoPhillips in terms of maintaining the viability of the unit and the project?

A. Yes, we do. Because we're trying to maintain our reservoir pressure, get it up, and improve oil production, and we need the injection wells in order to do that. We've been injecting CO_2 since 1995. So the injection wells being able to inject is critical to our performance.

Q. Unless you're able to get a unit-wide amendment to the rule, is it true that ConocoPhillips would have to come back to hearing every time to get an approved change to a packer setting?

A. That's correct.

Q. What does ConocoPhillips propose here as a resolution to this problem?

A. As a geologist, Cheryl mentioned, we -- from our top perf to -- from the top of the unitized interval to the average of our top perf, we've got about 250 feet in there.

What we propose is that we -- for us to set the packer as low as reasonably possible within the unitizing interval. That's one point I want to make, is that we don't go above the unitized interval and set our packers.

Q. In doing so, it will give ConocoPhillips the flexibility to maintain its project and still set its packers within the unitized interval and still protect correlative rights and overlying groundwater?

A. That's correct.

Q. Has ConocoPhillips evaluated the integrity of the casings of its injection wells, especially in the formations overlying the unit?

A. We have. We have a program with the OCD where we do Bradenhead tests every year and MITs every five years. And every well that fails MITs is remediated and the problem is fixed.

We do run casing inspection logs, cement bond logs on problem wells and also run, as a standard, cement bond logs on our new drills. So we know the quality of the casing, whether we have Swiss cheese down there or we just have a hole. And we do make attempts to squeeze the wells when we know we don't have Swiss cheese.

Q. Based on your analysis and study of the unit and these wells, will moving the packer setting above 100 feet in the uppermost perforation create a risk of vertical movement of injection fluid out of the unitized interval into the overlying formations, in your opinion?

A. In my opinion, no. Because we set our surface casing below the groundwater zone between 1,600 and 1,700 feet. We are well protected. You know, we cover the groundwater.

And as Cheryl mentioned, we have the Grayburg as a tight, low-permeability formation which protects us.

Q. And ConocoPhillips has seen no evidence, as Ms. Mnich mentioned and your testimony, has seen no evidence of any contamination of the injection fluids in the overlying formations; is that correct?

A. No, we haven't.

Q. Now, has ConocoPhillips reviewed the rules and regulations for the Federal Underground Injection Control Program to confirm that there's no requirement that the injection packers be set 100 feet from the uppermost perforation?

A. Yes, we have. On page 3 of Exhibit 6, it states in there that there are no requirements for injection packers and where injection packers can be set in Class 2 injection wells.

Q. So Exhibit 6, and correct me if I'm wrong, but there are basically two regulations from the Underground Injection Control Program, one that provides for the general provisions for mechanical integrity?

A. Correct.

Q. And another regulation are construction requirements for Class 2 wells, which are those that are related to oil and gas injection; is that correct?

A. That's correct.

Q. And in neither of those regulations does it specify a location for a packer setting; correct?
A. Correct.
Q. Now, as Ms. Mnich testified, she already referenced the Chevron Order R-4442-G. Can you please explain for the Examiners what it is that that order provided?
A. It provided that the injection packers are set as reasonably possible within the unitized interval, the packers in the injection wells.
Q. That order is provided in Exhibit Number 7; is that correct?
A. Correct.
Q. One thing also to point out that the order provides for is, in addition to approving the unit-wide setting of the packers above 100 feet, it also requires that Chevron seeks approval from the Division district office; is that correct?
A. That's correct.
Q. Each time it wants to set a packer above 100 feet?
A. Correct.
Q. Is there anything that would distinguish the circumstances between -- either geologically or engineering-wise between the Chevron units and

ConocoPhillips' unit and what they're seeking and what they've received in their amendment and what you're seeking today?

A. No, not that we're aware of.

Q. Were Exhibit Numbers 6 and 7 prepared by you or under your supervision?

A. Yes.

MR. RANKIN: Mr. Examiner, I'd like to tender for admission Exhibits 6 and 7.

EXAMINER JONES: Exhibits 6 and 7 will be admitted.

(Exhibits 6 and 7 were admitted.)

MR. RANKIN: I pass the witness.

EXAMINATION

BY EXAMINER JONES:

Q. Is this a fun job, monitoring the East Vacuum Grayburg-San Andres Unit?

A. It keeps me on my toes.

Q. How is your foreman to work with out there, pretty good people?

A. Very good people.

Q. I worked out there for three years when I first started in the oil patch in the Central Vacuum Unit.

A. Okay.

Q. We had Texaco's properties out there, which is right next to Phillips.

A. Right.

Q. In fact, one of our inspectors in Hobbs, Maxi Brown, was also -- he started in the vacuum field.

A. Yeah. I know Maxi pretty well.

Q. He's got a lot of experience.

A. Sure.

Q. I'll try to run through these pretty quickly. When you set a packer and it won't hold, how many times can you reset it, pull it up and try to reset it, before you have to redress the packer and pull it out?

A. We run locally made but very durable -- they call them Hudson packers. And we have very good reliability with them.

Most times we try -- we give more than -- at three times, if we don't get a good set, we have to pull it out and get a new packer. Actually, when we work on injection wells, we have to have a standby backup packer just in case we have problems setting the one.

Q. You have CO2. Is it a WAG project?

A. Yes, sir.

Q. Is every well getting some CO2?

A. No, it's not. Approximately, I would say 75 percent of the injectors are WAG. And the northwest part of the field is just more injection.

Q. Closer to the Chevron stuff is all being CO_2 flooded?

A. Yes.

Q. What about north of the Central Vac Unit? That seemed like pretty tight stuff to me. I saw on your map that the East Vacuum Grayburg goes right straight north of the Central Vac Unit.

A. Yes. That's the area where we have just water injection. The rock property is a little tighter. So it's just on a water flood, and a lot of the injection wells take very little to no water.

Q. Your pumps are -- are the pumps emanating water from the -- pretty close to that gas plant out there? Or do you have different pump stations around the unit?

A. We have a central tank battery which is next to our East Vacuum -- EVLRP, East Vacuum Liquid Recovery Plant. And that plant -- the CTB sends water not only to our East Vacuum Unit but also to our Vacuum Glorieta Unit.

Q. I was going to ask you about that. The Glorieta is being produced out there also?

A. Yes, sir.

Q. And the Abo?

A. Yes, sir.

Q. That plant, that recovery plant, your production gas, does it -- do you strip out all of the liquids?

A. We make about 25 million cubic feet of CO_2, about 80 percent CO_2 in the East Vac. And of that 25 million, we strip out about 800 barrels a day of NGLs.

Q. So you take the NGLs out, but do you also take the CO_2 and the H_2S out, or do you re-inject it?

A. We re-inject it.

Q. It's pretty much being re-injected unit wide, or in all of the CO_2 project area?

A. Correct. We buy some make-up gas from the Trinidad line and mix it with our recycled CO_2 and inject it into our area.

Q. So you probably have to have a pretty active corrosion program out there?

A. Yes, sir. We have a very active corrosion program. We have a company, Champion Chemicals, that takes care of our corrosion problem and take, very often, water samples, gas analysis, and make sure we have -- you know, nothing is out of the ordinary, so to say.

Q. Do you notice that your injection tubings, if they're coated, does the coating have to be resistant to

CO2? Will the CO2 go right through that coating?

A. We've done a lot of testing on our coating, and the TK-99, does not get contaminated with CO2. We have very few failures. And we have a very active failure analysis team, and we look at our injection wells and failures and packers.

And our coating, the only time we see problems is when we have insulation problems in the way the coating is put up. When put correctly, we don't see any issue with contamination of CO2.

Q. I imagine it's much more complicated than when it was just a water flood?

A. Yes, it is.

Q. Basically, it's -- you could almost consider it to be a lot of acid gas being re-injected?

A. Correct.

Q. What about water flows? Do you have to re-drill any wells because of all these --

A. We don't have any water flow issues. I know west of us in the vacuum, they have had some water flow issues. But we don't have any water flow issues in the East Vacuum.

Q. As far as monitoring the pressure on your injection wells, do you do it at a satellite or do you do it at the well head?

A. We do it at the well head. All our new injection system -- actually, we're going to a program to put in automation on all our old injection systems, which gives us casing pressure, flow rates and flow line pressure. So we monitor -- without the MIT yearly testing, we will have pressures on what the casing is on a regular basis on our injection wells.

Q. On a minute-by-minute basis?

A. Yeah. It takes a screen shot on a daily basis and averages it out and gives you a number, what the pressure is.

Q. Are you two stationed in Midland?

A. I'm in Odessa. She's in Houston. Our operations group is out of Odessa.

Q. From your office in Odessa, you can dial in and watch your wells?

A. Yes, sir. From Houston, from home. I can do it right now. I can see exactly what the pressures are.

Q. Okay. And if you wanted to run some step rate tests out there, do you do it yourself, or do you get a commercial service to come and do it?

A. We get a commercial service to come do it, and we just give them what rates they should go by.

Q. Is it pretty disruptive, pretty expensive?

A. The pump truck -- using the -- it's not expensive at all. It's about $4,000. If we have to use a downhole gauge and whatnot, that increases the cost.

But right now, the main issue is availability. All these pump trucks are working on acid jobs and new wells and whatnot. So trying to get one lined up to be able to get the wells done is an issue. That's why I want to just focus on an area, get a package and get them done all at once.

Q. Can you get by without bottomhole gauges, a bottomhole readout somehow on step rate tests?

A. They can monitor surface pressures from the well head while they're doing step rate tests. I believe the guidance we got was we needed to have downhole gauges for our step rate tests.

Q. We like downhole gauges, but I just wondered how much more inconvenient they are.

A. It's just a cost issue. It's not an inconvenience. It would be good data for us, as well.

Q. Do you have to continuously check your bottomholes on these wells? Do you have to clean out some wells?

A. Actually, we just did our release review earlier in the week. We look at our wells and see how much rate it's taking and pick candidates to go clean out.

First, we go with a slick line TAG and get a sample of the scale and give it to our chemical team and see if we can come up with an acid to dissolve it. And if it doesn't work, we go back with a rig and clean it out.

Q. Do you do a lot of injection profiles?

A. We do about -- I would say last year we did about 10 wells out of the 116. A lot of the wells aren't taking much, so we're trying to get more active with that. So getting tagging and cleaning out the wells will be first.

Q. What about production profiles?

A. We don't do much production profiles. We have a couple of wells that flow which we've run some production logs on. We have a lot of ESPs in the field, so we run downhole sensors on the wells to get an idea of the pressure. And we can run it up and down to give us a grade. In terms of where it's coming from, we don't do much of that.

Q. So you have downhole monitors on your pump units?

A. Yes. And we have downhole pressure sensors for the ESPs which give us real time on intake pressures and temperatures.

Q. And you start at 50 feet or as close as you can, and then you move up if you have to?

A. Correct.

Q. You don't think this is going to result in you having to re-drill some of your injection wells? Because you always try to squeeze them if they're not Swiss cheese, you said.

A. Correct. We do spend money on casing leaks and isolating them if we find one and reporting to the OCD and mitigating those.

Q. Do you have annuluses on all your injection wells, or have you cemented the tubing in the hole?

A. We have annuluses. We don't have any tubing cemented in the hole.

EXAMINER JONES: Thank you very much.

EXAMINER BROOKS: No questions.

MR. RANKIN: Nothing further, Mr. Examiner.

EXAMINER JONES: Thank you both for coming. We'll take case 14775 under advisement.

* * *

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

______________________, Examiner
Oil Conservation Division

REPORTER'S CERTIFICATE

I, JACQUELINE R. LUJAN, New Mexico CCR #91, DO HEREBY CERTIFY that on March 29, 2012, proceedings in the above captioned case were taken before me and that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with any of the parties or attorneys in this case and that I have no interest whatsoever in the final disposition of this case in any court.

WITNESS MY HAND this 10th day of April, 2012.

Jacqueline R. Lujan

Jacqueline R. Lujan, CCR #91
Expires: 12/31/2012