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:

CASE 15497

APPLICATION OF CONOCOPHILLIPS COMPANY TO MAKE PERMANENT THE AUTHORITY GRANTED UNDER ADMINISTRATIVE ORDER WFX-945 TO INJECT WATER, CARBON DIOXIDE AND PRODUCED GAS FOR ENHANCED OIL RECOVERY WITHIN THE EAST VACUUM GRAYBURG-SAN ANDRES UNIT; TO AMEND THE SPECIAL RULES ENACTED UNDER ORDER NO. R-5897 GOVERNING ENHANCED OIL RECOVERY OPERATIONS WITHIN THE UNIT; TO ALLOW ADMINISTRATIVE APPROVAL OF ADDITIONAL INJECTION WELLS WITH THE UNIT WITHOUT FURTHER NOTICE AND HEARING; AND TO CLARIFY THE SURFACE INJECTION PRESSURES AND INJECTION AUTHORITY PREVIOUSLY AUTHORIZED BY THE DIVISION, LEA COUNTY, NEW MEXICO

REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING
MAY 26, 2016
SANTA FE, NEW MEXICO

BEFORE: MICHAEL McMILLAN, EXAMINER
DAVID BROOKS, EXAMINER
WILLIAM V. JONES, EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, Michael McMillan, William V. Jones, David Brooks, Examiners, on May 26, 2016, at the New Mexico Energy, Minerals, and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

REPORTED BY: Mary Therese Macfarlane, NM CCR No. 122
Paul Baca Court Reporters
500 Fourth Street NW, Suite 105
Albuquerque, New Mexico 87102

A P P E A R A N C E S

FOR THE APPLICANT: Michael H. Feldewert, Esq.
Jordan Kessler, Esq.
Holland & Hart, LLP
P.O. Box 2208
Santa Fe, NM 87504-2208
(505) 983-6043

I N D E X

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P R O C E E D I N G S

(Time noted: 8:50 a.m.)

EXAMINER McMILLAN: Okay. I'd like to call back to order. I'd like to call Case No. 15497, Application of ConocoPhillips Company to make permanent the authority granted under Administrative Order WFX-945 to inject water, carbon dioxide and produced gas for enhanced oil recovery within the East Vacuum Grayburg-San Andres Unit; To amend the Special Rules enacted under Order No. R-5897 governing enhanced oil recovery operations within the unit; to allow administrative approval of additional injection wells within the unit Without further notice and hearing; and to clarify the surface injection pressures and injection authority previously authorized by the Division, Lea County, New Mexico.

Call for appearances.

MR. FELDEWERT: If it please the examiner, Michael Feldewert of the Santa Fe Office of Holland & Hart appearing on behalf of the Applicant.

I have two witnesses:

EXAMINER McMILLAN: Any other appearances?

(Note: No response.)

If the witnesses would please stand up and be sworn.

(WHEREUPON the presenting witnesses
were administered the oath.)

MR. FELDEWERT: Mr. Examiner, we will call our first witness.

EXAMINER McMILLAN: Please proceed

SUSAN BROWN MAUNDER,

having been duly sworn, testified as follows:

EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, identify by whom you are employed, and in what capacity.

A. My name is Susan Brown Maunder, M-a-u-n-d-e-r, with ConocoPhillips Company. I'm a senior regulatory coordinator.

Q. How long have you been a senior regulatory coordinator for ConocoPhillips?

A. Four years.

Q. Ms. Maunder, how many years of experience do you have in the oil and gas industry?

A. Twenty-two years experience in the oil industry. Nine years with a subsidiary of Shell Oil Company in Alaska, where I coordinated compliance and permitting for their exploratory and production operations.

That also included waterflood.

Q. What did you do after you were with Shell Oil

Company?

A. I had ten years experience with my own consulting firm. In that capacity I conducted some compliance audits for the industry up there in Alaska, and a large portion of my time was spent on the oil spill contingency plan for the Prince William Sound tankers.

Q. And in your last four years with ConocoPhillips, have your responsibilities included the Permian Basin?

A. Yes.

Q. In particular, Southeast New Mexico conventional assets.

A. Yes. The conventional assets in Southeast New Mexico, both federal and state units, new well permitting and associated compliance activities.

Q. And as part of your job responsibilities do you regularly work with the land department?

A. Yes, I work with the land department, engineering, and then the operations folks, in addition to the regulatory.

Q. Have your responsibilities included regulatory support for the secondary and tertiary recovery operations in what is known as the East Vacuum Grayburg-San Andres Unit?

A. Yes. My duties include that, in addition to the federal unit waterflood support.

Q. I'm just going to refer to that as the East Vacuum Unit. Okay?
A. Right.
Q. In fact, Ms. Maunder, have you not previously filed administrative applications for approval of additional injection wells for the East Vacuum Unit.
A. Yes, I have.
Q. Have you -- what is your educational background?
A. I have a Bachelor's of Science in Environment Assessment from the University of Washington in Seattle.
Q. And you have been through your work history. Have you previously testified before the Division as an expert in regulatory matters?
A. I have not.
Q. Are you familiar with the application filed in this case?
A. I am.
MR. FELDEWERT: Mr. Examiner, I will now tender Ms. Maunder as an expert witness in oil and gas regulatory matters.
EXAMINER McMILLAN: So qualified.
Q. (BY MR. FELDEWERT) Ms. Maunder, to get us set up would you please turn to what has been marked as ConocoPhillips Exhibit 1 in your exhibit book, and would you please first explain what unit is at issue here, and

then generally what is shown in this particular exhibit.

A. This exhibit shows the unit boundary on the ConocoPhillips East Vacuum Grayburg-San Andres Unit. It's noted as a blue vertical hatch.

Then to the west is the Chevron Central Vacuum Unit.

To the southwest of that is the Chevron Vacuum Grayburg-San Andres unit.

Q. And this is located in Lea County, New Mexico; is that right?

A. Lea County, New Mexico.

Q. Is the description for what is depicted on here as the East Vacuum Unit set forth in the application?

A. It is.

Q. Does this unit currently utilize both injection wells for water, CO_2 and produced gas?

A. Yes, it does.

Q. When did the waterflood operations begin?

A. The first approval was in 1979 and then waterflood started shortly thereafter.

Q. What about the CO_2 and produced gas? When did that gas injection begin?

A. CO_2 injection again in the mid '80s.

Q. If you turn to what has been marked as ConocoPhillips Exhibit No. 2, is that just a write-up containing a brief geologic description of the injection zone underlying this unit?

A. Yes, it is.

Q. Has that been prepared and certified by a geologist?

A. Yes, it has.

Q. Is that offered here today just in the event that the examiner has some -- want some general background about the geology underlying the unit?

A. Yes.

Q. But what is the real purpose of the hearing today?

A. The real purpose of the hearing is to satisfy some of the requirements of WFX-945 to come before the Division for hearing, and we would also like to standardize some of the prior approvals.

Q. Okay. If I turn to what had been marked as ConocoPhillips Exhibit No. 3, is that the Administrative Order issued in 2015 that has resulted in the hearing today?

A. Yes.

Q. Okay. And this particular -- first off, did you prepare the administrative applications that resulted in this Order?

A. Yes. They were prepared under my direction.

Q. Okay. And in fact did it involve two C-108 filings?

A. Yes, there were two separate C-108 filings.

Q. How many wells were involved in these two filings?

A. There was 11 wells in one of the filings and an additional well in the second filing.

Q. And if I turn to the second page of this Exhibit No. 3, this Administrative Order, does it approve the injection of water and CO2 and produced gas into the 12 wells listed?

A. Yes, it does.

Q. And before coming back to this Order, if we go to what's been marked as ConocoPhillips Exhibit No. 4, does this contain -- it's a two-page exhibit. And does it contain the areas of review that were examined by the Division in 2015 prior to approving the injection for these 12 wells?

A. Yes. It shows the half-mile radius around each of the proposed injection wells.

Q. Did ConocoPhillips also bring an engineer today to present any update necessary for this review?

A. Yes, they did.

Q. I want to go back to Exhibit No. 3, which is the Order WFX-945. And I want to go to the first page, and I have go down to the bottom, and there's some language down there.

Is that why we are here today?

A. Yes.

Q. Okay. What does this bolded language require the company to do?

A. It requires that we come back to the hearing -- come back to hearing within one year of beginning of injection and explain our results for our pilot CO2 project.

Q. Is that the WAG operation?

A. It is. It's known as the WAG.

Q. What does that stand for?

A. Water and Alternating Gas.

Q. As I read through this at this bolded language, it also provides that -- they ask the company to amend the -- it says exiting but I think it meant existing Division Orders to accommodate future expansion. Right?

A. Correct.

Q. Is that the second purpose of the hearing here today?

A. Correct.

Q. With respect to the first purpose, will the company bring in-- does the company have an engineer here today to discuss the results of the WAG operations today?

A. Yes, we do.
Q. Okay. And now with respect to the second portion of this requirement, did the company review the governing Orders and the existing rules to determine what amendments were necessary to accommodate future expanding of the WAG operations?
A. Yes, we did.
Q. Ms. Maunder, are you aware that -- so, for example, if you turn to what has been marked as ConocoPhillips Exhibit No. 5, is this the initial Order that -- under which injection operations commenced in this area as a pressure maintenance project?
A. Yes.
Q. We are going to go through this Order here in a minute to address some of the additional amendments that we see, but before we do that I think the last time, one of the last times the company was here, did they not obtain an amendment to the packer setting requirements set forth in this Order?
A. Yes, we have.
Q. So for example if I go to page 7 of this particular Exhibit No. 5, Order-5897 --
A. Yes.
Q. -- and I go to Rule 11, there was a requirement in there with respect to the packer setting?

A. Correct.
Q. And that setting has been amended by a subsequent Division Order, correct?
A. Yes, it has.
MR. FELDEWERT: Mr. Examiner, that would be R-5897A.
Q. We want to maintain that amendment?
A. Yes, we do.
Q. Now, with respect to the other aspects of this Order, first off if I go to page, now page 6, which are the special rules and regulations for what at that time was a pressure maintenance project, there are certain rules here -- and I'm going to list them briefly -- 2, 3, 4, 6, 7, 15 and 16, and they all relate to what they call a Project Area Allowable.
Does the company request that the Division abolish this Project Area Allowable set forth in these rules?
A. Yes, we do.
Q. If I go to -- and I want to keep your finger on Exhibit No. 5, but if I go to Exhibit No. 6, this is an Order that was issued by the Commission in May of 2014?
A. Yes.
Q. And it was for OXY's North Hobbs Unit.
A. Correct.

Q. Okay. If we go over to page 10 of Exhibit No. 6, and I go to page 10 of Exhibit No. 6, paragraph 6, it says the following: No limiting gas/oil ratio or oil allowable applies to this enhanced oil recovery project. Okay?

Now, this was for OXY's North Hobbs Unit, correct?

A. Yes, that's correct.

Q. Are you aware that is a tertiary recovery project?

A. Yes.

Q. Does ConocoPhillips seek the same relief today for its rig, East Vacuum Grayburg Unit?

A. Yes, we seek the same relief.

Q. So the elimination of what under the rules right now is that Project Area Allowable.

A. Correct.

Q. From your perspective, does a -- now let me step back.

This Project Area allowable was put in place when this was a pressure maintenance project, right?

A. That's correct.

Q. Back in 1979.

A. Yeah, that's correct.

Q. And you have now moved through a secondary into

a tertiary recovery project?
A. That's correct.
Q. In your opinion, does an allowable serve any regulatory purpose when you get to a tertiary recovery project?
A. I don't believe it serves the regulatory purpose.
Q. Okay. And that's why you seek the relief that was similarly granted by the Commission for OXY's tertiary recovery project?
A. That's correct.
Q. So that's the first one.
Second. If I am now at Exhibit No. 5 and I go to Rule 9 on page 6 -- I'm sorry, Rule 8 on...
A. Page 7.
Q. Page 7. Thank you.
It provides within that a requirement that wells be located no closer than 10 feet from the quarter-quarter line. Do you see that?
A. Yes.
Q. Does the company seek to eliminate that 10-foot distance requirement for wells within your East Vacuum Unit?
A. Yes, we seek the relief on the 10-foot setback for the quarter-quarters interior to the lease boundary or

the unit boundary.

Q. So just the interior, not the exterior.

A. Not the exterior.

Q. All right. And once again if I go to Exhibit No. 6, which is that Order entered by the Commission for OXY's tertiary operation, and I go back to page 10 again, and I go to paragraph 5 of Exhibit 6 on page 10, it says, "The well limitation for quarter-quarter sections set forth in..." -- and it provides the Division rule -- "...does not apply to active tertiary recovery projects and OXY is authorized to locate wells closer than 10 feet to a quarter-quarter section line or subdivision inner boundary within the North Hobbs Unit."

A. Correct. And ConocoPhillips Company seeks the same relief?

Q. Okay. So you got me.

So first off we want to eliminate the restriction on the 10-foot requirement, right? And then we also seek authority to, as necessary, locate more than four wells within a 40-acre tract.

A. Correct.

Q. So essentially the same relief that's granted here is what you seek for your particular project.

A. Correct.

Q. And in fact will the ConocoPhillips engineer here today confirm that this relief will allow the company to more easily locate wells within the unit for optimal recovery?

A. Yes, we have an engineer for that.

Q. Okay. Now let's go to the third topic. So let's go back to Exhibit 5, which are those special rules that were enacted for a pressure maintenance project.

And now I want to go to page 6 and look at Rule 5.

Ms. Maunder, this particular rule requires a submission of what they call -- a submission annually of a Weighted Average Project Area Reservoir Pressure.

Do you see that?

A. Yes.

Q. Okay. Was the Company able to determine the last time that this annual submission was provided?

A. We were able to find a submission of our annual pressure for 1992.

Q. And it has not been provided since that time?

A. Not that we have been able to determine.

Q. In your opinion, now that you have moved from a pressure maintenance project into a full-scale tertiary recovery project, does this submission appear to serve any regulatory purpose?

A. I don't believe it does.

Q. Are you asking that this Rule 5 requirement now be abolished?

A. We are asking that.

Q. And will the Company's engineer further discuss this particular rule?

A. Yes, the engineer can discuss this.

Q. Then another aspect of relief that is set forth in the application is to allow administrative approval of additional injection wells within the unit area without further notice and hearing.

A. That's correct.

Q. Okay. And if I go back again to Exhibit No. 6, OXY's Order, and I go to page 9, and I go to paragraph 3, again that's -- in that paragraph the Commission issued similar relief to OXY's North Hobbs Unit, right?

A. Correct.

Q. In other words, you could add additional wells without further notice and hearing.

A. Correct.

Q. Will this relief from your unit decrease the regulatory burden both for ConocoPhillips and the Division in moving forward with the development of this unit?

A. Yes, it will.

Q. And in fact this is the type of relief that would appear to be requested in WFX-945, right?

A. Yes.
Q. Where it asks for you to adjust the Order to allow future expansion.
A. That's correct.
Q. Okay. All right.
Now I want to go to a fifth topic of relief. Okay?
A. Yes.
Q. What did you find when you reviewed the various Administrative Orders approving injection wells within the unit since the tertiary recovery operations commenced in the mid '80s?
A. There's been a consistent maximum surface injection pressure for water of 1350 psi; however, there was two different pressures that were acceptable as maximum surface injection pressure for gas, CO_2: 1850 and 1800.
Q. So in some Orders it said 1800 and some Orders that say 1850.
A. Correct.
Q. What uniform surface injection pressure does ConocoPhillips seek here?
A. We seek the 1850.
Q. Will the project engineer presented here today address why the 1850 psi surface injection pressure is

appropriate for CO_2 and produced gas?

A. Yes, the engineer will discuss that.

Q. Okay. Finally, the last topic of relief, okay, has to do with a particular Administrative Order. Correct?

A. Correct.

Q. If I turn to what has been marked as ConocoPhillips Exhibit No. 7, this is Administrative Order WFX-887 that was entered in 2011.

Did you review the administrative application that was filed in 2011 prior to the issuance of this Order?

A. Yes, I reviewed the application.

Q. And what did the Company seek under that filed administrative application?

A. We did seek the 1800 psi for the two wells in question. Uhm, in discussing the more recent applications with engineering, the 1850 psi maximum level allowable surface pressure is appropriate.

Q. As part of that application, did you ask for approval of the injection of both water and CO_2 into the two wells that are at issue here?

A. That's correct.

Q. So if I look at the second page of this WFX-887, it lists the two wells, correct?

A. Yes.
Q. They were approved under this particular Order?
A. Yes.
Q. And it provides, does it not, the surface injection pressure of both water and CO_2.
A. Yes.
Q. Okay. But if I go to the first page and I go to the bottom under "It is therefor Ordered" it says the Applicant ConocoPhillips is hereby authorized to inject water into the unit.
A. Right.
Q. It doesn't specifically say CO_2, right?
A. Correct.
Q. Do you think this was an oversight by the Division?
A. Yes.
Q. Because you asked for both the water and CO_2, right?
A. We did, yeah.
Q. And got approved injection pressures for water and CO_2.
A. Correct.
Q. But for some reasons the word CO_2 didn't appear in that first sentence.
A. Correct.

Q. Is the Company here today just to confirm and ask for whatever amendment is necessary to confirm that they are authorized to inject both water and CO_2 into these two wells?

A. Correct.

Q. Okay. And then this would also then be subject to your request that there be a uniform approved surface injection pressure of 1850, correct?

A. Correct.

Q. All right. So we just went through a lot of relief. Is all of this relief requested and noticed under ConocoPhillips's application?

A. Yes.

Q. And turning now back to Exhibit No. 1, in preparation for this case did you instruct your land department therefore to provide notice or to identify the operators and mineral owners within a half mile of the unit boundary?

A. Yes, we did.

Q. Did you also instruct them to identify the surface owners within a half mile of the unit boundary?

A. Yes, we did.

Q. And was the Company able to locate the addresses of record for each of those affected parties?

A. Yes.

Q. If I turn to what has been marked as ConocoPhillips No. 8, is this an affidavit prepared by my office --
A. Yes.
Q. -- with the attached the list of affected parties?
A. Yes.
Q. All of these parties have an address, correct?
A. Right.
Q. And this reflects that notice of this hearing was sent to these individual parties with the cover letter that is included with this exhibit?
A. Correct.
Q. Okay. And did that notice list include Chevron, which operates the units to the west of the East Vacuum Unit?
A. Yes.
Q. And then in addition to that did the Company also provide notice by publication of this application in the Hobbs News Sundown there in Lea County?
A. Yes.
Q. Is that reflected in ConocoPhillips' Exhibit No. 9?
A. Yes.
Q. Were ConocoPhillips Exhibits 1 through 9

prepared by you or compiled under your direction or supervision?

A. Yes.

MR. FELDEWERT: Mr. Examiner, I would move the admission into evidence of ConocoPhillips Exhibits 1 through 9.

EXAMINER McMILLAN: Exhibits 1 through 9 may now be the accepted as part of the record.

MR. FELDEWERT: That concludes my examination of this witness:

EXAMINER McMILLAN: I just want to be clear. The first question I have is: The pressure for water is 1400 psi?

A. 1350 psi.

Q. Okay. The next question I have is I'd like you to clarify the vertical limits of the unitized interval.

A. We have an engineer that can discuss that matter further.

EXAMINER McMILLAN: Go ahead, Will.

EXAMINER JONES: Well, I guess the main question I have would be --

MR. FELDEWERT: May I interrupt you?

EXAMINER JONES: Yes. Go ahead.

MR. FELDEWERT: Mr. Examiner, in our application, in the first paragraph it references Order

5871 and identifies the description of the unitized interval. So it's in our application under paragraph 1.

EXAMINER McMILLAN: Okay. Go ahead.

EXAMINER JONES: Thanks for traveling all the way up here for this.

EXAMINATION

BY EXAMINER JONES:

Q. The 10-foot relief from the quarter-quarter, why do you need that? Are there some wells located closer than 10 feet to the quarter-quarter?

A. It's largely surface infrastructure constraints that we are now facing with the number of wells, various operators, various horizons that are being developed.

So it's surface constraints.

Q. Okay. So you do need to locate wells closer than 10 feet to a quarter-quarter section?

A. In some instances we have had to.

Q. Or is it a case of getting them surveyed, you know, with the well location? You always have that, right?

A. With our -- with our drilling pad layout?

Q. Yeah.

A. Sometimes it can be challenging to locate wells, and the surface constraint in this unit is the more prominent constraint.

Q. Okay. So sounds like we're gonna hear more about that a little bit later.

But the -- one of the issues that we have is we try to locate every well, you know. And so you'd have a footage location, right, with a well.

A. Uh-huh.

Q. But the footage location will basically boil down to -- will it not tell you what unit letter or quarter-quarter section the well is located in?

A. Correct.

Q. So you don't have -- there's not going to be an issue there about knowing whether it's in Unit A or B, for instance? If it's right on the line between A and B we need to know which one it's located in.

A. Right.

Q. Or are you saying that we want relief from that, from reporting a quarter-quarter?

A. I don't believe that we will locate a well so that it's straddling two different drilling units.

Q. Okay. So you want relief from the 10-foot. But how much relief do you want? Like a one-foot relief or a --

A. I'll have to discuss that with engineering.

MR. FELDEWERT: The only thing I can add, Mr. Examiner, is we certainly are not asking to eliminate the requirement to identify the unit particularly in which the well is located.

EXAMINER JONES: Okay.

MR. FELDEWERT: But similar to what they did in OXY. They said you can get closer to the 10-foot, as necessary.

But we are not asking that, you know, it be located on the line in any particular case such that you will not be able to identify where it's located.

Q. Okay. Do you agree with that?

A. Correct.

Q. So it would be a definite -- now, these tracts that these units are made up of, correct me if I am wrong, this is a statutory unit. Is that correct? Or is it a voluntary unit?

It has tracts that were put into the unit.

EXAMINER BROOKS: Right. But that could be either way. I mean --

EXAMINER JONES: It could be either way. It doesn't matter, they're still tracts.

EXAMINER BROOKS: Yeah. Typically almost any unit defines. That's the way people structure unit agreements is they define certain tracts and then come up with a tract participation formula.

MR. FELDEWERT: Mr. Examiner, I think in

answer to your question, I'm looking at Exhibit No. 5, and I'm looking -- so this is Order 5897, and I'm looking at "Findings" on the first page under paragraph 2.

EXAMINER JONES: Statutory unit.

MR. FELDEWERT: Yeah.

Q. (BY EXAMINER JONES) So, in other words, the issue -- there is not going to be in issue of wells located right on the line between tracts, because each tract is allocated based on participation parameters that are agreed upon. So I guess the well will be in one tract or another, it won't be straddling a tract, I guess.

A. It will not.

EXAMINER JONES: So we'll be fine there.

MR. FELDEWERT: Yes.

EXAMINER JONES: Okay. Okay.

Q. Then it seems like this was put on CO_2 in the mid '80s.

A. Correct.

Q. It wasn't back in the'70s, late '70s?

A. That's not my understanding.

Q. Okay. And it's still -- the -- you're not asking for more wells at this time, right? Is that correct? More wells for injection?

A. Not at this time.

Q. Do you have a digital list of all the wells approved for injection and the permits they were approved under, and the dates they were approved?

You're pretty thorough, I've seen your work, so I figured I would ask you that question.

A. Uhm, we do have a master tabulation of data --

Q. Okay.

A. -- that was submitted in conjunction with the 945 application.

Q. Okay.

A. However, we are in the process of extending that to the whole unit.

Q. Okay. For what now?

A. The whole unit.

Q. For the whole unit?

A. And the half-mile boundary.

Q. Yes. We do the same thing, we just -- I know you're really thorough in your work, so I thought I'd ask you to maybe -- sometimes we ask for lists from, through your attorney. You know.

So if you do have something like that you could sent it to us and we could maybe incorporate a hearing Order that includes a summary of all of the wells that are permitted, and then summarize everything in one Order. That way you don't have to research so many of them. You know?

A. That's our goal with this master tabulation of data.
Q. Okay. Okay. Are you kind of asking for that here, also, or are you just asking for the relief that you went through?
A. We are asking for the relief that was specified in satisfying the requirements of 945.
Q. Okay. The precedent and example was the North Hobbs? Or South Hobbs, is that it?
A. The north.
Q. It would be north?
MR. FELDEWERT: But I can tell you if you look at the Order of the South Hobbs Unit, it mirrors what was approved in the North Hobbs.
EXAMINER JONES: Okay. Mr. Catanach was involved in those from the word go, I'm sure.
MR. FELDEWERT: Well, I think with respect to the commission hearings that was done at the time when -- yeah, Jami Bailey was the chair.
EXAMINER JONES: Okay.
Q. Do you remember oversee the reporting of the production from each well?
A. I do not.
Q. Somebody else, some other group does the C-115?
A. Correct. We have production accounting that

takes care of the C-115 --

Q. Okay.

A. -- reporting.

Q. Okay. In previous years we've taken one form requirements for reporting and for injection disposal and moved it to the C-115. So I guess the 126. I'm not -- I could be wrong on that.

But anyway, on the right side of the 115s there's a requirement to report pressures on the injection wells. So can you check and make sure OXY's reporting -- I'm sorry, ConocoPhillips is reporting the pressures on that for these East Vacuum?

A. That activity is underway.

EXAMINER JONES: Okay. Okay. I don't have any more questions.

EXAMINER McMILLAN: No questions.

EXAMINER BROOKS: Well, I guess there was some question about whether this is a statutory unit, and I don't see anything that indicates that it is, although I don't know. But in looking at the Order that was done, it seems to me this is approved as a waterflood project. I don't see any provisions nor have I seen any separate Order that deals with the unitization issues. So I am inclined to believe it probably was a voluntary unit but, I don't know.

MR. FELDEWERT: The only thing I can go on is to look at Exhibit 5, and I look at paragraph 2.

EXAMINER BROOKS: Paragraph 2? Which --

MR. FELDEWERT: On the first page of Exhibit 5. It says Division Order 5871 back in 1978, statutory unitization area approved.

EXAMINER BROOKS: Where is this? You said paragraph 2.

MR. FELDEWERT: I am on Exhibit 5, which is Order 5897.

EXAMINER BROOKS: Okay So it was a statutory unitization. Yeah. I thought you were calling my attention to Finding 3, and I didn't look.

MR. FELDEWERT: I'm sorry. I was looking at the first page of Exhibit 5.

EXAMINER BROOKS: I see what you are talking about now. So presumably it is a statutory unit, unless its status has changed in some way.

Thank you. Just wanted to clarify for the record.

MR. FELDEWERT: Call our next witness.

EXAMINER McMILLAN: Let's take a 10-minute break.

MR. FELDEWERT: Sure.

(Note: In recess from 9:33 to 9:43 p.m.)

EXAMINER McMILLAN: Okay. Let's go back on record in case No. 15497. Please proceed.

MR. FELDEWERT: Mr. Examiner, we would call our next witness.

GREGORY FRITZ SALTZ,

having been previously sworn, testified as follows:

EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, by whom you're employed, and in what capacity.

A. Yes. My name is Gregory Fritz Salts. I'm employed by ConocoPhillips and I'm a reservoir engineer. My primary responsibility is reservoir surveillance for the East Vacuum Grayburg-San Andres Unit.

Q. How long have you been a reservoir engineer for ConocoPhillips?

A. For just over two years.

Q. And throughout that entire time have your responsibilities included this particular unit.

A. Yes.

Q. Okay. And have you previously testified have before this Division?

A. I have not.

Q. Would you outline your educational background, please?

A. Yes. I graduated in May of 2014 with a Bachelor of Science in petroleum engineering from the University of Oklahoma.

Q. And then did you start work with ConocoPhillips after that?

A. Yes.

Q. Were you previously employed by ConocoPhillips while you were in school?

A. Yes. I had an internship in the summer of 2013 with ConocoPhillips working on the East Vacuum Grayburg-San Andres Unit.

Q. Are you a member of any professional organizations or associations.

A. Yes. I'm a member of the Society of Petroleum Engineers.

Q. How long?

A. For two years now.

Q. Okay. Are you familiar with -- you said you are familiar with the East Vacuum Grayburg-San Andres Unit.

A. Yes.

Q. That's been your unit.

A. Yes.

Q. Are you familiar with the Application that's been filed by the Company?

A. I am.

MR. FELDEWERT: I would tender Mr. Salts as an expert in petroleum engineering?

CHAIRMAN McMILLAN: The only problem is I have a lot of kinfolk who -- I have two kinfolk who got petroleum engineering degrees from Oklahoma.

A. Oh-oh.

CHAIRMAN McMILLAN: I guess I'm forced to accept him as an expert witness.

EXAMINER BROOKS: Well, I won't object even though I'm from the University of Texas.

MR. FELDEWERT: Okay.

Q. I want now to -- Mr. Salts, if you would look at the WFX-945, which is Exhibit No. 3, and asks that the Company return and discuss the pilot project that has been ongoing?

A. Yes.

Q. Okay. And this particular Order references approval of 12 wells with respect to this particular project. How many of the 12 wells are actually involved in what is referenced here as a pilot project?

A. So 11 of the 12 wells are dedicated to the TZ/ROZ, which is the zone we are targeting with the pilot. The 12th well was grouped in by request from the Division and it is a main pay only injector.

Q. If you look at the second page of Exhibit No. 3, which well is the main pay injector?

A. The first well on the list, No. 400.

Q. And the remaining 11 wells are associated with this pilot project?

A. Correct.

Q. Okay. Now, you mentioned the pilot project being the TZ/ROZ.

A. Yes.

Q. Okay. If I turn to what's been marked as ConocoPhillips Exhibit No. 10, does this assist in identifying what you mean by the TZ/ROZ project?

A. Yes. TZ/ROZ stands for Transition Zone/Residual Oil Zone, and if you look at the graph in the bottom left of this exhibit it explains what we mean by TZ/ROZ. You have a saturation profile that corresponds with the graph to the left.

And our main pay has traditionally been higher original oil saturation. This is a part of the reservoir that we can target with water or primary production, and the transition zone transitions from waterflooding target to residual to water injection, meaning the only way that we can recover oil in the residual oil zone is through tertiary processes.

Since 1985 we have targeted the main pay oil zone with CO2 injection, so we have further decreased the oil saturation from residual to water injection to something close to residual CO_2. So the unexploited target here is the TZ/ROZ, which is what we are seeking with this pilot project approval.

Q. What is the grey box?

A. I was going to get to that.

The cross section seen on the top corresponds to the black line on that map on the bottom right. And this is the portion of the reservoir that the pilot project is in. So we're targeting everything below the negative 700 subsea line which runs across the entire cross section.

The pink faces is the poorer reservoir quality rock, the blue is higher reservoir quality. And our upper San Andres and lower San Andres is bisected by impermeable sandstone layer known as the Lovington.

Notice how there's a higher concentration of good quality reservoir in the lower San Andres, mainly in the TZ/ROZ. This is one of the main reasons we want to exploit this resource.

Q. All right. These guys are smarter than I am but I was confused the first time around. The black line actually is a demarcation between the main pay and the TZ/ROZ zone?

A. Correct. So that's the traditional oil/water contact.

Q. Does that grey box, does that simply identify, at least on this cross section, the geographic area of the pilot project?

A. Yes. Well, the pilot is in Section 33, which is east of the line of section. The grey box denotes what reservoir we expect to see in the pilot area.

Q. Okay. All right. Now, when did this pilot project commence?

A. 2011.

Q. Okay. Then if I go to now what has been marked as Conoco Phillips Exhibit No. 11 --

First off, while I've got my finger on 10, there is a box here outlined in, what's that, orange? Like in Exhibit 11.

A. Yes.

Q. Does that geographic area correspond with the grey box on Exhibit No. 10, roughly?

A. Yes.

Q. Okay. All right. Now, with that said, why don't you explain a little further what is shown here on Exhibit No. 11.

A. So within the gold box there's several wells. We have included both of the main pay injection and production wells, as well as the pilot wells. So the pilot injection wells are the large blue circles within the box and the pilot TZ/ROZ-only production wells are the 3373-500, 3333-508, which is a brownish-green color.

In addition we wanted to test what a main pay and TZ/ROZ commingled producing well would look like, and in order to do this we deepened the 3333-008, which is right in the center of the box, to test that commingled concept.

Notice that the injectors and producers are in a line drive orientation from the northeast to the southwest. Preferential permeability direction in the reservoir is from the northeast to the southwest, and over time we have converted the injection wells as we see breakthrough.

So also with this pilot we drilled these wells in locations of 20-acre infills. In case the pilot was unsuccessful we could bail out of the TZ/ROZ and complete in the main pay.

Q. Now this particular exhibit just shows the wells associated with the East Vacuum Grayburg.

A. Correct.

Q. Looking ahead to a request to locate more than four wells and get closer than 10 feet, are there a lot of other wells and other facilities within this geographic area?

A. Yes. In this area of the county there are three overlapping units, East Vacuum Grayburg-San Andres Unit, Vacuum Glorieta East Unit, and Vacuum Poppa (phonetic) Unit, all operated by ConocoPhillips. In addition there is some nonoperated wells that penetrate the San Andres inthis zone and we've identified over 1,000 wells, penetrations through the San Andres.

Q. So there's a lot of facilities, a lot of wells within this particular unit.

A. We have facilities, pipelines, electrical infrastructure, and then of course the wells from all the operations in the area.

Q. Okay. Now, getting back to the pilot project that started in 2011, what did you learn from this initial effort here in the TZ/ROZ?

A. Pilot production results were positive and we deem this a commercial and technical success, and that's why we are seeking approval for the next phase of the pilot.

Q. Okay. If I turn to what has been marked as ConocoPhillips Exhibit No. 12, does this assist in identifying technically what you learned from this initial effort that started in 2011?

A. Yes. So what's seen in this exhibit is a production plot from the three production wells within the pilot area. The production, the actual production is marked by the green line. Our forecasted production prior to the project is shown in the black dashed line and then our well count is the red dashed line, so meaning what wells were on during what month.

So the one thing I want to point out is that the flush production or the large spike in production that we did not anticipate with our forecast, we've attributed that to flush production where we have injected CO_2 below the Lovington Sandstone but within the main pay that has mobilized some of the oil in the transition zone.

After producing that flush the relatively flat production you see is associated with mobilized oil by the pilot.

Over time you will see a dropoff in the fourth quarter of 2014. We started to have gas handling issues. Our gas processing plant can only process so much gas every day, so based on a GOR hierarchy, we will shut in producing wells. And one of the wells within the pilot area was too high of a GOR to make that cut-off.

Q. Do you currently have capacity issues?

A. Yes.

Q. And we will get to that in a minute, but you're working to address those, correct?

A. Yes.

Q. Now, you mentioned that this has been a commercial and technical success for the company. Roughly how much oil has been produced from this initial pilot project that we saw on Exhibit No. 12?
A. So to date with four to five years of production we have produced just over 230,000 barrels of oil.
Q. And are you seeing what would indicate a sustained oil production rate?
A. Yes. The decline rate is within the range of what we would expect with this field.
Q. Now getting back to WFX-945, is this success, is that what caused you to initially come before the Division for approval to expand this pilot project?
A. Yes.
Q. If I then turn to what has been marked as ConocoPhillips Exhibit No. 13, does this assist in orienting the examiners both to the initial pilot project and then the areas in which you seek to expand with the wells approved under WFX-945?
A. Yes. The original pilot is in the pink box in the center of that plot. The 11 injection wells and the nine producing wells in the next phase of the pilot are within the orange boxes. We decided to expand the pilot to the west and south where we saw the most favorable results in production. So we wanted to expand that way

knowing that we would have positive results.

We also wanted to test another portion of the reservoir which is denoted by the orange box in Section 27 to see what the extent of our TZ/ROZ target could be within this unit.

Then the green seen behind all the orange, if this pilot phase is successful, it opens up a lot of doors to expand the TZ/ROZ full field.

Q. Again, this particular exhibit just depicts the wells that are part of the East Vacuum Grayburg-San Andres Unit?

A. Correct.

Q. What is the status now, today, of these expansion efforts that are reflected with the orange boxes and which encompass the wells involved in WFX-945?

A. So of the 11 injection wells permitted we have drilled six to date. We decided to suspend drilling operations due to the industry environment and also to wait for completion of our gas compression facilities.

Q. So of the six that have been drilled, are they injecting yet?

A. No. They are drilled but not completed.

Q. And has the company currently engaged in construction to accommodate a gas plant expansion?

A. Yes, we are currently adding an additional

20,000,000 cubic feet a day of processing capacity to the field. This project will be completed in October of 2016.

Q. With respect to the wells approved under WFX-945, the eleven wells that are part of this project, when does the company hope to complete those, drill and complete those wells?

A. From the results of our 2017 budgeting we will be drilling those wells in the summer of 2017.

Q. Are they actually on your rig schedule?

A. Yes, sir.

Q. And as a result, is the company here then today pursuant to WFX-945 to make the authority that has been granted permanent?

A. Yes.

Q. Will that allow the company to proceed with regulatory certainty as economics improve?

A. Yes.

Q. Okay. And in your opinion will the permit approval of injection authority granted under WFX-945 allow the company to recover additional oil that may otherwise be left unrecovered in this TZ/ROZ?

A. Yes.

Q. All right. Now, keeping a finger on Exhibit No. 13 and then turning back to those bubbles that we saw in an earlier exhibit, which is Exhibit 4, am I correct that the first page of Exhibit No. 4 corresponds to the expansion area shown on Exhibit 13, the larger orange box.

A. Yes, this corresponds to the southwestern orange box.

Q. Okay. And then does the second page of Exhibit No. 4 correspond to the smaller orange box on Exhibit 13 up there in Section 27?

A. Yes.

Q. Okay. In preparation for this case here a year later, did you review the records to determine whether there had been any new wells drilled through the injection zone or any additional plugged wells that had been drilled through the injection zone that were not reviewed at the time that the application was initially filed?

A. Yes.

Q. What did you find?

A. Since last year we have drilled an additional nine wells within the areas of interest seen in these two plots. All wells were drilled by ConocoPhillips. Three of them were in the Vacuum Glorieta East Unit and the six East Vacuum wells were all injection wells associated with this pilot project.

Q. Okay. And with respect to those nine new wells, if I -- separately, outside of this package, there is a sheet that is labeled in the bottom-left-hand corner, Wells in the Area of Review Drilled since WFX-945 Approval.

Has that been marked as Exhibit 14?

A. Yes.

Q. And does this provide a tabulation of information on those nine drilled wells that you referenced?

A. Yes. We documented each casing stream, their casing set depths, their cement tops behind pipe, and of course their legal descriptions.

Q. Okay. Now, did you find that -- did you determine whether there had been any additional plugged wells that had been drilled through the injection zone within those areas of review?

A. We did not find any plugged wells since the last application.

Q. In your opinion are the recently drilled wells within the area of review sufficiently cased or cemented to prevent migration of the injection fluid out of the proposed injection interval?

A. From what I know, yes. However, with the six new injection wells we have yet to run CBLs, which we are doing within the next month. So we will verify casing and cement integrity.

Q. Then I want to go to another topic. We touched on this briefly, and that is the current restriction on the number of wells that can be located in a 40-acre tract and then the requirement that they remain at least 10 feet from the quarter-quarter section line.

You have discussed the various infrastructure that's out here. Do you anticipate that your continued development of this unit will eventually, if not now, require more than four wells per 40-acre tract?

A. Yes.

Q. And I'm going to represent to you, Mr. Salts, that there is a division rule, it's 19.15.15.9A that currently under its text only authorizes more than four wells per 40 acres under the text for quote/unquote secondary recovery operations. Okay?

Is there any engineering reason to allow more than four wells per 40-acre unit for secondary recovery operations but not for tertiary recovery operations?

A. No, sir.

Q. In your opinion, would the allowance of more than four wells per 40-acre tract allow ConocoPhillips tertiary recovery operations to proceed more efficiently?

A. Yes.

Q. Then with respect to this 10-foot setback on quarter-quarter lines, have there actually been occasions in your development of this unit and with your tertiary recovery operations where the desired well location was impacted by this 10-foot setback?

A. Yes.

Q. Okay. And will the elimination of that 10-foot setback requirement provide the flexibility that the company needs to efficiently and effectively locate wells for optimum oil recovery?

A. Yes.

Q. All right. Then I want to go to Exhibit 5, which is the current Order R-5897.

And we know there's been one amendment to these rules, and we are seeking some additional amendments.

A. Okay.

Q. So first off, if we go to page 6. And were you here for the testimony of Ms. Maunders where we are discussed the project area allowable that is set forth in Rules 2, 3, 4, 6, 7, 15 and 16?

A. Yes.

Q. And you're aware that those were established when this unit was first approved for initially a pressure maintenance project.

A. Yes.

Q. You now moved beyond that, right?
A. Correct.
Q. You are in a tertiary recovery operation to try to recover whatever oil remaining that you can get out of there, right?
A. Right. We are on a very mature tertiary process.
Q. In preparation for this hearing did you take the time to actually calculate the allowable that would be afforded under this formula in these rules?
A. Yes.
Q. What did you find?
A. I found that based on the allowable calculation and the amount of the unit we have developed, current production is less than 30 percent of the unit allowable.
Q. So it's currently not serving any purpose?
A. Correct.
Q. And do you anticipate that your production will ever get to the allowable level?
A. With the aggressive full-field development of TZ/ROZ and infills in the main pay it would be a stretch to get to that allowable number again.
Q. I guess you wouldn't mind if you were able to recover that additional oil?
A. I'd have no complaints.

Q. In your opinion, does a project area allowable serve any purpose when you've got to the point were you are engaged in tertiary recovery operations?

A. I don't believe it does.

Q. Okay. All right.

Then if I stay on this same page, page 6, under Rule 5 there is a requirements in here to annually submit a Weighted Average Project Area Reservoir Pressure. Do you see that?

A. Yes.

Q. And as you read through it actually requires the operator and then the Division's Hobbs office to select 10 representative wells in the Unit, and then from those 10 wells determine annually this Weighted Average Project Area Reservoir Pressure.

A. Yes.

Q. Now, again when this was put in place this was a pressure maintenance project, right?

A. Yes.

Q. And there has also been testimony that the last time that this was done was back in 1992.

A. From what we could find in our internal records the last submission was 1992.

Q. Now, knowing this was initially put in when it was a pressure maintenance project, and knowing nobody has done it since 1992, do you have an opinion as to the possible purpose for which this requirement was put in place in 1979 when this was a pressure maintenance project?

A. Yes. In my opinion when they enacted this rule in 1979 it was in order to track the progress of ConocoPhillips in repressurizing the reservoir for tertiary area operations. In order for CO2 to be efficient, an efficient form of tertiary flooding you need the reservoir pressure to be above a term known as ** minimum miscibility pressure, in which case our Unit minimum miscibility pressure is about 1350 psi in the reservoir. So with the Pressure Maintenance Order we waterflooded until we were confident that our minimum miscibility pressure was greater than that, and then at that point in time we began CO2 injection.

Q. So does it appear to you that this was in fact a tracking mechanism to determine when you would be ready to do the CO2 flooding?

A. Correct.

Q. And then thereafter to determine that you maintained sufficient pressure to get that -- what was that term you used?

A. Minimum miscibility pressure.

Q. Today are you able to maintain the -- is there any doubt about your ability to maintain the minimum miscibility needed to effectively maintain this tertiary recovery project?

A. I don't have any concerns. The previously granted maximum surface injection pressures for both water and CO2 allow us to manage the reservoir pressure adequately without exceeding the parting pressure. In addition we constantly monitor our surface injection, pressures, and also we have some bottom hole pressure gauges on downhole submersible pumps, and as we come across pressure issues we remediate them and answer any questions we have at that point.

Q. So in your opinion does this Rule 5 serve any purpose given the project's status today?

A. No. We have every incentive to manage our reservoir pressure.

Q. So the company therefore requests that this particular rule, like the Project Area Allowable, be abolished?

A. Yes.

Q. Now, you talked about surface injection pressure, so I want to talk about that topic now.

Are you aware that the Division at some point determined that surface injection pressure of 1350 psi for water posed no threat to the reservoir?

A. Yes.

Q. If I turn to what has been marked as ConocoPhillips Exhibit No. 15, is this a letter from the Division, signed by Joe Ramey back in 1983, authorizing within the East Vacuum Grayburg-San Andres Unit a 1350 surface injection pressure for water?

A. Yes.

Q. Now, since the movement of this project to a tertiary recovery project -- you were here for the testimony where there has been some inconsistency with respect to the approved surface injection pressure for CO2 and produced gas?

A. Yes.

Q. For example if I turn to what has been marked as ConocoPhillips Exhibit No. 16, it contains three Orders, Mr. Salts, PMX-176 which was entered in 1995, PMX-228 which was entered in 2005, and then PMX-246 which was entered in 2006.

And each of these Orders approved a surface injection pressure of 1850, right?

A. Yes.

Q. Okay. And some of these reference CO2 and others reference produced gas. Is there any reason to treat -- in terms of the surface injection pressure, is there any reason to treat CO2 any differently from produced gas?

A. No. Our injected stream is a blended process produced gas and pure CO_2. Our processing system is set up where all produced gas from the producing wells flows through the East Vacuum Liquid Recovery Plant where we extract natural gas liquids and compress the residue gas, which contains over 90 percent CO_2, a little bit of H_2S and nitrogen and a small amount of methane.

So that gas stream is compressed, and then downstream of the discharge of the plant, we blend that with our CO_2 which is purchased off the Trinity pipeline.

Q. So you no longer inject pure CO_2.

A. No. The stream that leaves that blend goes to all injection wells.

Q. In your opinion, is the approved surface injection pressure of 1850 psi for CO_2 and produced gas, is that consistent with an approved surface injection pressure of 1350 psi for water?

A. Yes.

Q. If I turn to what has been marked as ConocoPhillips Exhibit 17 -- first off, is this your work?

A. Yes.

Q. And what do you -- what did you do here?

A. The goal of this was to determine what surface injection pressure for CO_2 and produced gas would be necessary to match the bottom hole injection pressure equivalent to 1350 psi on water.

Q. All right.

A. So with that calculation, we determined that 1850 psi on CO_2 and produced gas is necessary to equate to that same bottom hole pressure on the water.

Q. Now, is it important that you have the same bottom hole pressure for water and CO_2 and produced gas?

A. Yes. Since we are in a WAG process we inject both water and CO_2 in our injection wells, so one month we will inject water, at which point we will then switch the injection well to CO_2. And if the bottom hole pressures are not equivalent or if the CO_2 injection pressure is not enough to sustain that bottom hole pressure, we won't be able to inject any CO_2 in the reservoir.

The same goes with water if we are switching the other way.

Q. Now, is therefore the company request that the Division clarify by Order that the approved the surface injection pressure for CO_2 and produced gas is 1850 for this unit?

A. Yes.

Q. And in your opinion is a surface injection pressure of 1850 psi for CO_2 and produced gas necessary to efficiently and effectively operate this tertiary recovery project?

A. Yes.

Q. And in your opinion, will the approval of 1850 psi for CO_2 and produced gas pose any threat to the formation?

A. No. All step rate testing that I've seen has shown a parting pressure greater than that injection pressure.

Q. And those step rate tests were made in part for when the Division determined the correct psi for water?

A. Correct.

Q. Mr. Salts, will the overall relief that's sought under this Application allow for the recovery of additional wells that may otherwise be --

A. Yes.

Q. And will the granting of this application be in the best interests of conservation, prevention of waste and protection of correlative rights?

A. Yes.

Q. In your opinion does the relief requested under this application post an unreasonable risk to the public health or the environment?

A. No.

Q. Were ConocoPhillips Exhibits 10 through 17 prepared by you or compiled under your direction or supervision?

A. Yes.

MR. FELDEWERT: Mr. Examiner, I would move the admission into evidence of ConocoPhillips Exhibits 10 through 17.

CHAIRMAN McMILLAN: Exhibits 10 through 17 may now be accepted as part of the record.

MR. FELDEWERT: That concludes my examination of this witness.

EXAMINER McMILLAN: Go ahead, Will.

EXAMINER JONES: First of all, thank you for coming. And I like the Sooners, too, so...

THE WITNESS: I got someone on my side.

EXAMINATION

BY EXAMINER JONES:

Q. I guess I'll kind of work backwards here.

So the surface injection pressure for CO2 of 1850 will get you to where you need to be for minimum miscibility pressure? It's fine, you're above the minimum miscibility?

A. Correct.

Q. What about -- and for water, did you determine you don't even need 1350? Is that correct? You could go less than that for water?

A. In my opinion no. So if we were to decrease water injection pressure at this point and we didn't decrease CO_2, when you WAG a well your near well bore reservoir pressure is going to be that of what you just injected. So if you're switching an injection well to a product that cannot have the same injection pressure down hole, then we won't be able to establish injectivity.

Q. You can't get enough water in the ground either; is that correct?

A. Correct.

Q. Okay. So you're fine with a permit that says 1350 and 1850?

A. Correct.

Q. And for the -- just specifically for the 12 wells we are talking about here?

MR. FELDEWERT: No. No, as you will see with some of the prior Administrative Orders, for whatever reason some said 1800, some said 1850. So what we are asking for here and what we have requested in the applications is a unit-wide basis so we have consistency across the unit.

EXAMINER JONES: Okay.

Q. The temporary tests that were run, they are run on the whole main pay, though, right?

A. Correct.

Q. So they would be probably fracturing at a lower pressure, you think, than the residual zone?

A. It's the same San Andres Formation. As you get deeper your fluids in the reservoir are also at a higher pressure so your rock has additional support. So your parting pressure should be pretty linear.

Q. Yeah. You got geologists in the back. I can tell they're grimacing right now. Because when you get down in that residual zone you may have differences in the amount of fracturing going on, too; is that correct?

A. I don't think I can answer that.

Q. Okay. Okay. Yeah, it's just -- do you have any stress logs up and down the hole, like Dipole sonics or FMIs on any new wells drilled?

A. So with these 11 injection wells, we plan on running FMIs on a few of them to understand what type of fractures we may have or may encounter.

Q. Okay.

A. So that is in our data collection plan.

Q. It's still pretty expensive to run FMIs.

A. I can't answer that question, either.

Q. It used to be expensive to run it and expensive to process. The processing was about as much as running it. So...

A. Yeah. It won't be in every well, it will be in few where we think we may encounter seismic issues.

Q. That Lovington Sands, does that -- your model, your cross section, I guess Mike will probably ask you about that, but it doesn't cover the whole unit; is that correct?

A. Can you repeat that?

Q. That Lovington Sands is a boundary, and -- well, actually there's some main pay below those Lovington Sands, correct?

A. Correct.

Q. Before you get to your transition zone.

Right. So, yeah, so as you -- the East Vacuum is -- the depositional environment was along the shelf margin of the northwest shelf, so as you're moving towards the shelf margin and, you know, where the geology was prograding over, the Lovington sandstone pinched out.

Q. Okay. So how much further down is the Glorieta from --

A. The Glorieta is --

Q. From where you're injecting.

A. The Glorieta is almost 1,000 feet.

Q. Oh, okay.

A. So it's pretty far down. There's a large section of San Andres below our TZ/ROZ target.

Q. Which is 100 percent water?

A. Yeah.

Q. Or high water?
A. Yeah. Not commercial.
Q. Okay. Not commercial.
No horizontal drilling out here?
You are aware of Apache's new units that they formed to drill horizontally in the low productivity San Andres to recover some -- you know, where you couldn't recover it from vertical wells?
A. Yeah. I'm not aware of any of that.
Q. But you are not doing any horizontal drilling?
A. So in 2003, or 2002 to 2003 we drilled 17 horizontal wells, horizontal sidetracks.
Q. Okay.
A. And that was to try to capture oil out of not the worst reservoir quality but actually our best reservoir quality section.
Q. Oh, okay.
A. So the zones where we were able to get a lot of CO2 and mobilize oil we wanted to try to capture that resource that was trapped between the vertical well bores.
Q. Did you find areas that were original pressures between -- or areas that were varied pressures where the waterflooding hadn't contacted?
A. We had quite a variation of results in those wells. So actually the ones that existed as good vertical

wells before we built the sidetracks would normally perform poorly as horizontal wells, meaning we were able to sweep oil better in those portions of the reservoir.

So the horizontal wells that performed better contacted oil that wasn't being swept very well but had been mobilized by CO2.

Q. Okay. You said something about 20-acre well spacing. Are you not on 10-acre well spacing out here?

A. Well, it depends on what orientation you're looking at. So the way we are -- if you go to actually Exhibit 13, you'll see that, uh -- when we talk about spacing a CO2 flood we are talking about the spacing between the injectors and the procedures.

Q. Okay.

A. So that right now, if you look at two injectors and two producers would be about 40 acres, but if we split that line with another producer, another injector, that's what we're referring to as a 20-acre infill.

Q. I was looking at well density.

So overall well density, do you have the same number of injectors as you do producers?

A. No. We have an injector/producer ratio -- or sorry, procedure-to-injector ratio of about 2:1.

Q. Oh, really.

A. Yeah.

Q. Okay. So you've got kind of a line drive from the northwest to the southeast --
A. Yeah.
Q. -- oil injectors, but you've got actually more procedures in between the lines than you do injectors.
A. Right. So we call that a semi line drive orientation.
Also, in the northern part of the unit where we don't inject the CO2, the poorer reservoir quality, we are not on a line drive, we're on an inverted five-spot pattern. So that also brings up your injector/producer ratio.
Q. So within these pilot areas did you say something about maybe changing the density in some of those areas to -- is that for help with your model or is that with an actual field test?
A. So let's see if I can answer that.
So we drilled those TZ/ROZ-only injectors and procedures in those -- meaning if they weren't successful we could use them as 20-acre infills in the main pay.
Q. Okay.
A. But as far as in the TZ/ROZ, they are less dense.
Q. Okay. Are you using any analogy between

Chevron's residual zone or the Wasson field, or do you have your own waterfloods you're looking at for analogy for residual?

A. Yeah. So the East Vacuum Grayburg-San Anders Unit is the only CO2 flood within ConocoPhillips portfolio. However we have nonoperated interests in the Central Vacuum Unit and the Wasson Denver Unit.

Q. Okay.

A. So in addition to my role as reservoir surveillance engineer for East Vacuum, I also manage those nonoperated projects in the Denver Wasson.

So all future developments, technical justification, we are vetting through how they determine their development potential in those two units.

Q. So you talk to --

A. We are in contact with those engineers, and I reads all the AFEs, and run economics on everything like that.

Q. So do you maintain the model for the water for this project?

A. No, I don't.

Q. You got modelers in Houston or somewhere that keep track of it?

A. Well, we did.

Q. Oh, we did. Okay.

A. However, all modeling done for justifying this TZ/ROZ project was done in the 2013 time frame, and that was what we used to develop the AFE flow stream.

Q. Okay.

A. So after the fact as far as post projects learnings and understanding, we'll do some more modeling efforts.

Q. Okay. These wells that are on this WFX, at the time it was written there was only one of them permitted for drilling, so it had an API, the others didn't have APIs. And you went through all that in your testimony, so I can read it again.

But it says in there at 12 months of the date of the first injection. Do we know the date of first injection in any of those?

A. So, because the 3308-400, which is a main pay injector, was included in that list, it was already drilled and completed.

Q. Okay.

A. So that's what started the clock for one year from injection.

Q. And you made the application within a year, so you have met the obligation.

MR. FELDEWERT: Yes, sir. We were very careful about that.

EXAMINER JONES: Yeah, yeah.

MR. FELDEWERT: Because that's the one thing we checked. We checked the wording of the Order, and they did want the application filed within a year. So we met that and got the hearing here today to present the results.

EXAMINER JONES: Okay. So I was just trying to think if there is any other timing issues that's going to put us up here on Saturday nights real late.

Maybe not.

MR. FELDEWERT: No. No. In other words -- no, there's not, because --

EXAMINER JONES: Well, we won't let it languish.

Okay. Well, let me go down the list here, make sure I've...

Q. At one point I thought Phillips totally had a Ryan/Holmes situation out there --

(Note: Reporter inquiry.)

A way to process. Gas processing where they totally split out everything like they do in the Seminole-San Andres Unit. I don't know if the Denver Unit does that anymore.

A. Yeah. So we do employ the Ryan/Holmes technology, their EVLRP, however we don't have a deep methanizer, so we extract all the heavies, but we compress.

Q. Okay. Methane and ethane are still together.

A. Right. That actually helps our minimum miscibility pressure.

Q. Oh, does it?

A. Keeps it low, because we are reinjecting some hydrocarbons.

Q. Okay. And everything's a SCADA system out there? You can see it from your -- are you living in Hobbs or...

A. I wish. No, I'm in Houston. But we have a good SCADA system that shows us all the meters and pressure transmitters throughout the field, and we also use a program called XSPOC, which links directly to the wells that have pump off controllers and water injection controllers.

So we are almost fully automated.

Q. Do you -- what's your injection withdrawal ratio that you have out there? Is it 1:1, about, or...

A. Yeah. So as a unit we produce about 25,000 barrels a day from the unit, but we inject about 40 into East Vacuum.

Q. Okay.

A. We are also tied into the Vacuum Glorieta's East

Unit injection system, so with their water they produce goes through our central tank battery for repressurizing so that they can inject.

Q. Okay. So do you look after the Glorieta, also?

A. I do not, no.

Q. What about the lease line wells between the Central Vacuum and the East Vacuum? Is that every other well is -- you know, one is yours and one is Chevron's? Is that the way it works?

A. I'd have to look at the lease again, but I believe we operate four and they operate two.

Q. And they're not going down as deep in the transition zone, are they?

A. Those are all main pay. The lease line is dedicated to main pay.

Q. So there's also some upside there, maybe.

A. Absolutely. That is one of best portions of the reservoir.

Q. Just make sure we got everything covered here. I think Mr. Feldewert usually covers everything, but...

Basically you want on order that summarizes everything, and you need the 10-foot -- 10 foot.

Can you -- we already talked about that enough, I guess, but do you have any comments on it?

A. So we don't anticipate ever straddling one of the drilling units.

Q. Okay.

A. However, as close as we can get would be optimal.

Q. Okay. So you want your wells to be reservoir driven and not driven by land issues.

A. Right. And with CO_2 floods, because CO_2 is so mobile in the reservoir, and location of wells and the development of patterns makes a big difference in overall recovery.

Q. Okay. Do you have anything -- these guys probably need to ask questions, but do you have anything else that you want to say about this?

A. No.

EXAMINER JONES: I'll turn it over to these guys.

EXAMINER McMILLAN: Have they satisfied all this?

EXAMINER BROOKS: I'll make it easy. I have no questions.

EXAMINER McMILLAN: Okay. I just want to make sure --

EXAMINER JONES: Contingency plans? Do you have that?

COMMMISSIONER McMILLAN: (Reading) The

installation of automatic shutoff equipment at the wellhead to prevent the outflow of gas due to mechanical failure at the well.

Do you have something like that?

THE WITNESS: Could you say that again?

EXAMINER McMILLAN: The installation of automatic shutoff equipment at the wellhead to prevent the outflow of gas due to mechanical failure.

Do you have something like that?

Q. (BY EXAMINER JONES) If your wellhead -- if something happened -- if your wellhead, where you control -- this arose from acid gas wells where we started requiring 100-feet deep in the well a sort of a check valve.

But what kind of well restriction equipment do you have? Can you describe it?

A. On the injection site?

Q. Yeah.

A. So we have pressure-limiting devices at our header system, so at the discharge of the plant and at the discharge of our water injection turbines. And those are set by Operations, and as they start to reach that maximum allowable pressure, Operations will either WAG wells to keep the pressure down or we'll start shutting in water production, as necessary.

In addition, on each wellhead we have chokes and pressure gauges and pressure transmitters on the upstream of the choke at the well tubing, and also on the casing. So operators are in the field throughout the day, and the wells that we have outfitted with water injection controllers they can watch from the office. The SCADA system shows all of our emergency shutdown valves on the CO_2 injection system throughout the field.

Q. Okay.

A. So...

Q. And you don't put any fresh water in, or if you do, you put oxygen -- take the oxygen out of it?

A. I know we have some fresh water that we'll use for plant operations, but as far as injection it's all produced water.

Q. Okay. Any scaling problems that you have to deal with?

A. Always.

Q. Always?

A. Yeah. We're -- one of my main responsibilities is trying to diagnose what's going on with our injection wells, and attempting to remedy that. And that's vital to managing our injection withdrawal ratio, keeping the minimum miscibility. I mean keeping our pressure above minimum miscibility.

Q. How do you separate the main pay from your residual zone in wells that are going to be dually completed? Do you have a packer system or...

A. No. So we're currently for the next phase of the pilot still sticking to the TZ/ROZ only.

Q. Okay.

A. However, in that one well that we commingled in the original pilot, we deepened open hole, which is similar to how OXY does it in the Denver Unit Wasson Field.

Q. Okay.

A. And known injection conformance issues, we would not want to commingle injection between the main pay and the TZ/ROZ, but we would want to commingle production at some point if it's commercial.

Q. Okay. So that's kind of in the future.

A. Yeah.

EXAMINER JONES: Okay. Does that...

That may be everything we have. We are going to get questions on the 10-foot deal, but I think we can explain it to the Hobbs district.

MR. FELDEWERT: Well, I guess what I would point out is that the Commission granted that relief at both hearings, both for the North Hobbs and the South Hobbs. Basically the testimony was the same. We are going to keep it within the unit but just need that flexibility because of the environment.

EXAMINER JONES: Okay.

EXAMINER McMILLAN: The only question I have is about the heterogeneity of the reservoir, and you described that with your description of the horizontal wells.

EXAMINER JONES: We have a geologist here.

MR. FELDEWERT: Unless you have more questions, let me kind of bring us back here, because I don't want -- there's a couple of things I want to keep in mind, and that is: If you look at our application there is really two things going on. Okay? The fact that the application has an A and a B.

There's two things going on. We had to come back under that WFX-945 to meet the requirements of that Order, which we believe we have done here today, to make that injection authority permanent. So that was the first aspect of this application. And so questions dealing with that project and then those, you know, 11 additional pilot project wells in the 400, that is kind of one package of relief.

The next package of relief deals with the entire unit. Not just these wells but the entire unit.

And you will see that we've identified

certain governing rules that, at least we believe we show don't serve any purpose here, in fact create a hindrance to the development of this unit.

One of those rules, Rule 11, had already been addressed by amendment to this Order, 5897, and you will see it's even referenced on page 3 of Exhibit 3, which is WFX-945, because it, at the top, cites that Order R-5897A dealing with what the packer is supposed to be set.

So that has been addressed.

But as we went through this, there were other aspects of these rules as set forth in 5897 that we ask be abolished and eliminated, and then there's certain clarifications that we asked for with respect to prior Orders.

My point is all that applies to the entire unit, not just the pilot project.

So I wanted to make sure I made that clear.

EXAMINER McMILLAN: Okay. With that in mind, Case No. 15497 shall be taken under advisement at this time, and thank you very much.

MR. FELDEWERT: Thank you.

(Time noted: 10:04 p.m.)

STATE OF NEW MEXICO)

) SS

COUNTY OF TAOS)

REPORTER'S CERTIFICATE

I, MARY THERESE MACFARLANE, New Mexico Reporter CCR No. 122, DO HEREBY CERTIFY that on Thursday, May 26, 2016, the proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the proceedings set forth herein, and the foreoing pages are a true and correct transcription to the best of my ability and control.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with (unless excepted by the rules) 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.

____

MARY THERESE MACFARLANE, CCR
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