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 NO: 16504

APPLICATION OF NGL WATER
SOLUTIONS PERMIAN, LLC
FOR APPROVAL OF SALT WATER
DISPOSAL WELL IN LEA COUNTY,
NEW MEXICO

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

MAY 30, 2019

SANTA FE, NEW MEXICO

This matter came on for hearing before the New Mexico Oil Conservation Division, Examiners Michael McMillan and Leonard Lowe, and Legal Examiner David Brooks, on Thursday, May 30, 2019, 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: Irene Delgado, NMCCR 253
PAUL BACA PROFESSIONAL COURT REPORTERS
500 Fourth Street, NW, Suite 105
Albuquerque, NM 87102
505-843-9241

APPEARANCES

For the Applicant:	DEANA BENNETT 500 4th St. NW, Ste 1000 Albuquerque, NM 87102
For BC & D:	GARY LARSON 218 Montezuma Avenue Santa Fe, NM 87501

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EXHIBIT INDEX

EXAMINER McMILLAN: Now what I would like to do is call Case Number 16504, Application of NGL Water Solutions Permian to Approve a Saltwater Disposal Well.

Call for appearances.

MS. BENNETT: Good morning. Deana Bennett on behalf of NGL Water Solutions Permian, LLC.

MR. LARSON: Good morning, Mr. Examiner. Gary Larson of the Santa Fe office of Hinkle Shanor for BC & D Operating. I don't have any witnesses.

EXAMINER McMILLAN: Any other appearances?

MR. FELDEWERT: Which number is this.

EXAMINER McMILLAN: 16504.

MR. FELDEWERT: What number is it on the docket?

EXAMINER McMILLAN: 68.

MS. BENNETT: Good morning. I also have with me Dean Coleman from my office, and he'll be assisting me with OCD matters going forward. And I have three witnesses -- four witnesses with me here today.

EXAMINER McMILLAN: If the witnesses would please stand up and be sworn in at this time.

(Witnesses collectively duly sworn.)

MR. BROOKS: Let me state for the record that the decision that was made was to hear this case, and since no one has indicated that there is any -- if there are any parties that had been noticed that it was to be continued who are not here with no -- we are going to continue it at the conclusion of the testimony so that if there is any objection anywhere to having heard it.

If anybody has been told that it's been continued, and they don't know it's not, then those parties will be allowed to present anything they want to present and take any procedural steps they can take at that time, but the order will be deferred until we have given that opportunity.

MS. BENNETT: If I can just ask some clarification for the record. What additional notice are you anticipating? Because I have, as you will see from my Affidavit of Notice, I have sent letters to all affected parties and published.

MR. BROOKS: And you noticed them for the original date for which this was set. What was that day, May 3rd?

MS. BENNETT: May 2.

MR. BROOKS: May 2, that's what I thought. Let the record reflect all parties were noticed for May 2, and a continuance was previously granted from May 2 to May 30 -- May 31 or May --

MS. BENNETT: No, May 30. So I'm not clear who would have notice that would be entitled to present.

MR. BROOKS: Well, the -- the purpose is to be sure -- the purpose is -- and let me explain. I do not know who granted this continuance or how it got in the record as continued. I gather neither of you knows how it got continued.

MS. BENNETT: Yes, I do know, Mr. Brooks. The week before May 2 Mr. Larson and I were in --

MR. BROOKS: No, what I said, how it got continued from the May 30 setting -- how it got marked continued on their sheet to May 30.

MS. BENNETT: I have no idea how that happened.

MR. BROOKS: Nor does anybody else for that matter.

MS. BENNETT: Okay.

MR. BROOKS: Okay? So I don't contemplate giving any further notice because if you noticed the case is going to be on a certain day and you choose not to attend, you may miss out on the notice it's been continued, but that's the risk you take.

MS. BENNETT: I just wanted to make sure that there wasn't any particular concerns that you had about particular parties who may not have been noticed.

MR. BROOKS: No, there are none. There are no such concerns. I have no idea who may have been noticed at this point.

MS. BENNETT: That's all I wanted to make sure about, is if there is a particular issue, then I wanted to be able --

MR. BROOKS: I do intend to find the person who granted that continuance that was on the docket sheet that it was to be continued and ask that person, him or her, if it was her, why it was done, and whether there were any issues that needed to be considered. But assuming we don't find out anything, we're not requiring -- I do not plan on requiring any new notice because I can't see why it should be.

MS. BENNETT: Thank you.

With that I would like to call my first witness.

EXAMINER McMILLAN: Are there any statements that anyone wants to make before we get started?

MR. LARSON: I don't have any.

EXAMINER McMILLAN: Okay, then, please proceed.

MS. BENNETT: At this time I would like to call Mr. Neel Duncan.

NEEL LAWRENCE DUNCAN

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Good morning, Mr. Duncan.

A. Good morning.

Q. If you would, please state your name for the record.

A. Neel Lawrence Duncan.

Q. For whom do you work?

A. Integrated Petroleum Technologies.

Q. You have been retained by NGL; right?

A. Yes, I have been retained by NGL.

Q. What are your responsibilities for NGL?

A. Drilling and development of saltwater disposal wells in Southeast New Mexico.

Q. And you have previously testified before the Oil Conservation Division and Oil Conservation Commission; is that right?

A. Yes, I have.

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

A. Yes, they were.

Q. Does your area of responsibility as a consultant for NGL include the area of Southeastern New Mexico?

A. Yes, specifically Eddy and Lea Counties.

Q. And are you familiar with the Cobra applications that were filed in this case?

A. I am.

Q. And are you familiar with the Cobra Saltwater Disposal Well that's the subject of this application?

A. Yes, I am.

MS. BENNETT: At this time I would like to tender Mr. Duncan as an expert in operations and engineering matters.

MR. LARSON: No objection.

EXAMINER McMILLAN: So qualified.

BY MS. BENNETT:

Q. Mr. Duncan, can you please turn to Tab 1?

A. Here.

Q. And behind Tab 1 is Exhibit A-1, and that is the amended application that NGL filed; is that right?

A. That's correct.

Q. And why did NGL file an amended application?

A. This is for the moving of the location.

Q. And what brought you to change the location?

A. Working with Lewis Energy, an operator of horizontal or plans for horizontal development in the area, they asked us to make sure we don't injure their horizontal development.

Q. Great. And so the amended application includes that proposed change in location?

A. Yes.

Q. And but nothing else would change in the C-108?

A. No.

Q. So the wellbore in this diagram is the same as

well as in the original C-108?

A. Yes, it is.

Q. Great. Let's go ahead and -- what does -- do you know if the change in location changed the parties that were entitled to notice? It didn't, did it?

A. No. We typically notice well more than the rule requires, so we had some leeway to notice that you can move wells as required by operation.

Q. And what does NGL seek in this application?

A. We seek approval to drill and operate a saltwater disposal well in the Devonian -- can't see the codes on your thing, but it's the Silurian-Fusselman group.

Q. And NGL is seeking to have a larger tubing size -- a large tubing size for this well; is that right?

A. That's correct. Seven-inch by five-and-a-half inch tubing.

Q. What's the goal of that larger tubing size? Why is NGL seeking that larger tubing size?

A. It reduces friction, and as you will hear from additional witnesses, it reduces horsepower, gets more water in the ground in one well, so you reduce the number of wells that are required for injection.

Q. And I would like to turn to Tab B now.

A. Okay.

Q. Tab B-1 and Tab B-2 are the administrative

applications for the West Jal Deep well and the order approving the West Jal Deep well; is that right?

A. That's correct.

Q. And is that, to your knowledge, the well that is operated by BC & D Operating?

A. Yes, it is.

Q. And BC & D Operating is represented by Mr. Larson, is that, to your knowledge, right?

A. Yes, that very kind gentleman.

Q. And they protested -- they're objecting to NGL's application; is that right?

A. Yes.

Q. Have you had a chance to review the BC & D order and application?

A. I have.

Q. And what is the authorized injection zone for that application?

A. Let me look at my cheat sheet. As I recall, yes, it's Strawn, Atoka, Mississippian, Devonian and Fusselman, but it's only completed in the upper portion of that.

Q. Through the Atoka?

A. Through the Atoka.

Q. So it's not currently injecting into the Devonian or Fusselman?

A. That's correct according to the records that we have on file at this stage.

Q. And when you, you have reviewed the C-108; right?

A. I have.

Q. And you have reviewed the wellbore diagram?

A. I have.

Q. And does NGL have concerns about the wellbore diagram based on your experience that you have with drilling and operating XWBs and wellbore diagrams and designs that NGL has submitted, do you have some concerns in your experience?

A. I have concerns in that this well penetrated the Precambrian basement when it was drilled and it was originally, I believe, an Ellenburger producer, and they -- they drilled it through the granite.

Q. And when you looked at the C-108 and wellbore diagram, did you notice areas of concern about how the well was --

A. Well, I don't find anything in the records, including, for example, a cement bond log that would give confidence that basement is isolated from the Ellenburger and that they -- that there's no communication path between the Devonian and the basement.

My experience with wells in, in Colorado that have penetrated the basement, I have had experience with three wells there, and there's an area of induced seismicity around those wells, even though they were plugged back after some earthquakes had occurred.

So there, even with plugging back, there is still some risk of communication because the wellbore penetrated the basement, and there is really no way of knowing without a good cement bond log that we have isolation and even that could be suspect.

The NGL went to even Oklahoma, where we have no business in Oklahoma, but we advised the Corporation Commission there to, to ensure that they required plugbacks at least 400 feet above the basement in the Arbuckle, they go 100 feet and they still have seismic issues in Oklahoma.

So there is an issue when you penetrate the basement, and I don't know that I would be -- I still have some concerns about, about injection into the basement if this well is allowed to inject into the Devonian.

Also, in reviewing the records I could not find an injection survey. The injection survey in this case was required within two years after the start of injection. That time has elapsed. The order required a revoke -- a revocation of the injection authority if that was not done. I don't know if it's a records issue at NMOCD, but there is no injection survey for that well in the file.

Q. Anything else that you would like to say on that topic before we move on?

A. I didn't see the record of the squeeze in the Ellenburger, so there's not -- so the isolation between -- if they drill out the bridge plug above the top the only isolation is a cast iron bridge plug with sets of cement.

Q. Okay. Well, if you wouldn't mind then turning to Tab C. And then Tab C affidavit was prepared by me that confirms that notice was sent to all the parties in the case.

A. Yes, ma'am.

Q. Behind Tab C is information about the mailing. March 20 is the date that the amended application was mailed out.

A. Yes.

Q. And behind that a few pages back is a sheet that has a blue header on it, or black header that shows the status of the mailing. Do you see that? It looks like this. (Indicating.)

A. Yes.

Q. And behind that is an affidavit of publication. Do you see that?

A. I see that.

Q. So NGL used that exhibit as proof that NGL notified all affected parties located within a mile of where the well was located and published notice of its amended application?

A. That's correct.

Q. Were tabs -- the exhibits behind Tab 1, Exhibits A, B, and C -- were A and C created by you or prepared under your supervision or direction or compiled from company business records?

A. Yes, they were.

MS. BENNETT: I will say that I pulled Exhibit B from the OCD records myself, which is the C-108 and order for the BC & D exhibits. At this time I would like to move that Tab 1, Exhibits A, B and C be admitted into the record.

MR. LARSON: No objection.

EXAMINER McMILLAN: Exhibit 1, parts A, B and C may now be accepted as part of the record.

(Exhibit NGL 1 admitted.)

MS. BENNETT: Thank you. I have no further questions for Mr. Duncan.

CROSS-EXAMINATION

BY MR. LARSON:

Q. Good morning, Mr. Duncan.

A. Good morning.

Q. The map in your exhibit shows the location of BC & D's West Jal B well, I will just refer to it as West Jal B?

A. Yes, sir.

Q. Have you calculated the distance between the West

Jal B well and the NGL proposed well?

A. I did, and my memory is probably worse than some, but it's -- I think it's about 1.2 miles.

Q. If I said it was 6050 feet, would that --

A. That's close, isn't it?

Q. But in any event, it's less than 1.5 miles?

A. Yes, it's less than one, but greater than one mile.

Q. And have you had communication with Donnie Hill who is the president of BC & D about your initial application?

A. Yeah, a long time ago even before this move.

Q. Would it be within the last year maybe?

A. Yes.

Q. And what did Mr. Hill discuss with you in terms of BC & D's objection to the well?

A. He just asked that we move it.

Q. Because of the proximity to BC & D?

A. Yes, because he had a permit to inject into the zone.

Q. Have you had any subsequent discussions with Mr. Hill?

A. No, sir.

Q. And you talked about moving the well location in response to some concerns from a Lewis. Is the new location

actually closer to BC & D's well than the initial?
A. It may be slightly, but I, I don't -- I don't remember making that comparison.
Q. I'm going to direct your attention to the document marked as BC & D Exhibit B-1, which is the administrative order SWD-1482. And if you look at the second paragraph that's highlighted, what is the approved interval for injection by the BC & D?
A. As I testified, the Strawn, Atoka, Mississippian, Devonian, and Fusselman formations.
Q. And that's 11708 feet to 16439 feet?
A. Yes.
Q. So that does include the Devonian?
A. It does. Yes, that's -- that is what we call the Devonian.
Q. And I'll next draw your attention to the document marked BC & D Operating Exhibit 2 which is a form C-103 for the West Jal B well, dated October 31, 2018.
A. Yes.
Q. And if you look at the highlighted portion on Page 1, does it show that BC & D intended to add perfs in the Devonian and Fusselman formations to increase disposal capacity?
A. Yes, it does.
Q. And if you will go to Page 3 of the exhibit, this

indicates the proposed perfs in the Devonian?

A. I can't really read them, but it's --

Q. It's very small language. I to expand it on my computer.

A. But, yeah, I think the word says perfs, yeah. I can't read it.

Q. Devonian might need a looking glass.

A. It's does not -- it does say Devonian. I can't read the number, yeah.

Q. And if you go back to Page 1, if you look at the bottom there, it shows it was approved by Maxey Brown of the OCD on November 1, 2010?

A. Yes, it was approved at the district level.

Q. And are you aware that the West Jal B well is a commercial disposal well?

A. Well, I don't know fully -- yes, I guess it is a commercial disposal well, yes.

Q. And given the proximity of BC & D's West Jal B well to NGL's proposed well, would you agree there is a potential for interference between the wells?

A. Possibly, but I -- I will not testify that, you know, maybe you can cross some other witnesses on the interference issue with some of the engineers.

Q. That's something that's somebody else's expertise?

A. Yes.

Q. And I understand NGL is seeking a maximum injection capacity of 50,000 barrels per day?

A. Yes, sir.

Q. And assuming that NGL injected 50,000 barrels a day, and BC & D also injects 50,000 barrels a day, could you foresee any operational problems either or both companies would confront?

A. Well, BC & D's well covers a 7000 foot injection interval, so that 50,000 barrels a day. I think the well is quite high capacity now going into the Atoka and the Strawn. It's taking like 50,000 barrels a day now, isn't it?

Q. They are not injecting that much. I'm just saying --

REPORTER: One at a time.

Q. -- that both parties take it to the maximum level of 50,000 -- and I understand you're not qualified to talk about interference, but could you foresee any operational difficulties for either or both companies?

A. Not really, no, I don't see operational difficulties.

Q. And why is that?

A. Well, the only operational difficulty I see is, I am still concerned about the communication with the basement with this well.

Q. Okay. But the OCD approved the C-103 for the additional perfs without raising any of the issues that you have testified to this morning; correct?

A. I don't know that those issues were very high profile back when this order was written.

Q. Well, but the C-103 was put in November of last year?

A. By the district. I don't know -- I don't know what is involved in the -- I'm not going to speculate as to process or anything in the OCD, but I don't know if the RSC would actually look at that approval that was signed by --

Q. Do you think they looked at it in 2014 when the administrative order was issued?

A. I -- maybe, but we've been -- the issue of the injection and this risk around that came to light probably last year in New Mexico. It's been -- it's been a big issue for the OCD to try to manage and ensure there is no induced seismicity created by the sudden increase in injection requirement.

Q. And in light of that, is there any possibility of induced seismicity if NGL's proposed well and BC & D's well are both injecting 50,000 barrels a day?

MS. BENNETT: I will object to that question because we do have a witness here who is an expert in that field who will be testifying. I mean, Mr. Duncan, is qualified to a certain experience, but we have a technical witness.

MR. LARSON: I will direct my question to another witness.

MR. BROOKS: Do you pass the witness?

MR. LARSON: Yes, I do.

MR. BROOKS: What is the distance between the proposed well and the BC & D well?

THE WITNESS: I think Mr. Larson had it at 6000.

MR. LARSON: Approximately 6050 feet.

THE WITNESS: Yes. I had it in my mind 1.2 miles, but that's about the --

MR. BROOKS: More than one mile?

THE WITNESS: More than one mile.

MR. BROOKS: But less than one and a half miles?

THE WITNESS: Yes, sir.

MR. BROOKS: Thank you.

EXAMINER McMILLAN: My first question is the same question I asked, when was that connection to the source, was that done after the proposed location change?

MS. BENNETT: I believe in this case it was done before the proposed location change, but the location was only moved a few hundred feet.

EXAMINER McMILLAN: Well, let's make it clean.

MS. BENNETT: Okay.

MR. BROOKS: When the location was changed, was it changed -- did it change the distance between the -- the distance from the BC & D well?

THE WITNESS: Well, geometry and math would say it would, but I don't know how far. It wasn't that far, we didn't have to move the well that far.

MR. BROOKS: How far did you move the well?

THE WITNESS: We have the two plats.

MS. BENNETT: Yeah. The first plat is behind Tab -- behind A-1, and the original is, in this case is --

THE WITNESS: It was something -- it was just a couple hundred feet.

MR. BROOKS: Okay.

THE WITNESS: It was -- we just had to scoot it closer to the section line to get it out of way of the horizontal well.

MS. BENNETT: Right, so it was proposed at -- if this is okay with the Examiner for me to read it into the record.

EXAMINER McMILLAN: Please.

MS. BENNETT: Originally it was proposed at a surface location 325 feet from the North line and 718 feet from the east line of Section 19, Township 25 South, Range 36 east.

And it's now changed to 325 feet from the north line, so moved one foot away from the change in the north line, and 268 feet from the east line. So the main change was going from 718 feet from the east line to 268 feet from the east line, so about 450 feet closer to the east line.

MR. BROOKS: Does anybody -- do either of you know when was -- what that does to the distance between the proposed well and the BC & D well?

MS. BENNETT: I will represent for the record that it's moved it closer to the proposed well, but I do not know how much closer.

MR. BROOKS: Okay. It takes trigonometry to figure that out probably.

MS. BENNETT: May be somewhat complicated math, but I just didn't do it, and I apologize for that, but we can certainly figure that out on a break if that's meaningful to the Examiner because we have the location of the West Jal Deep well, so we could probably use math and my i-Phone to figure it out.

MR. BROOKS: Okay. Well, that would be helpful to have that part of the record because I'm sure there's going to be a review of this record before an order is entered.

EXAMINER McMILLAN: Okay. Is that everything?

MR. BROOKS: I'm through.

EXAMINER McMILLAN: I wasn't clear what you were stating about the cast iron -- the cast iron bridge plug is 1300 feet above the Ellenburger? Is that right, for the BC & D?

THE WITNESS: It's at 10,000 -- no, I'm sorry. It's hard to read it, but it's 20,000 -- or 12,100 feet, I believe -- no, it's not that -- 17,100 feet.

EXAMINER McMILLAN: The Ellenburger at 18444?

THE WITNESS: Yes 18444 is about the perfs, and the granite is 18920, and the TD is 18965.

EXAMINER McMILLAN: This says 945, but that doesn't really matter.

THE WITNESS: Yeah, that could be a 4.

EXAMINER McMILLAN: It's hard to tell. So you think, based on your experience, even though they are 1600 feet above basement there could still be seismic conductivity?

THE WITNESS: Well, we don't know what the status of the cement is.

EXAMINER McMILLAN: Just for the record, cement where?

THE WITNESS: The annular cement behind that line.

EXAMINER McMILLAN: Because there is no --

THE WITNESS: There is no bond.

EXAMINER McMILLAN: No CBL?

THE WITNESS: Yeah, no CBL, and so there is just no -- don't know the status of it.

MR. LARSON: Mr. Examiner, can I interrupt briefly? What diagram are you looking at?

THE WITNESS: The wellbore diagram that's in the --

EXAMINER McMILLAN: Color display, it says BC & D.

THE WITNESS: Behind the -- behind the C-103.

MS. BENNETT: This is Exhibit 2.

MR. LARSON: Is it the one with the red outline?

EXAMINER McMILLAN: Yes.

MR. LARSON: Okay. Thank you.

THE WITNESS: The well was drilled in the 1970s, so it's an older well.

EXAMINER McMILLAN: Yeah.

THE WITNESS: So I just have a lot of mechanical integrity concerns with older wells, as should the state.

EXAMINER McMILLAN: And we're going to make you do -- would require bottomhole pressure for the well.

THE WITNESS: On the Cobra.

EXAMINER McMILLAN: Well, if it's approved, we are going to require that.

THE WITNESS: Oh, yeah, of course.

EXAMINER McMILLAN: And then would you be willing to come back to a hearing if this is approved, and say, different intervals, say, maybe after five or or ten years and show revised modeling and things of that nature?

THE WITNESS: Sure. Anything you want to require.

EXAMINER McMILLAN: And I assume you would be -- and also the pressure, like I said, and any modeling you would be willing to work with the state so we can -- so you have cooperative effort beforehand to work with the state to show your modeling, anything of that nature. Would you have any objection to that?

THE WITNESS: No. We would also like to see, you know, something from the BC & D well cement bond log, of that, of that interval to make sure at least there is some cement there and -- and an injection profile because I do -- I have -- I have concerns of, of that water, that water taken getting to the basement which will -- which is bad for anybody the disposal business.

EXAMINER McMILLAN: And are there any other wells, injection wells within a mile, a mile and a half?

THE WITNESS: Not in the Devonian.

EXAMINER McMILLAN: Any questions?

EXAMINER LOWE: One quick question, you were asked to move this well for what reason?

THE WITNESS: Anti-collision with the horizontal.

For the horizontal. When horizontal wells are placed, you have very little control of Azimuth, but very good up and down control. But Azimuth control is weak, and so we have to -- well, what we would like to do is set our wells out into the required setback from the section line, so as long as you're inside that setback, that well shouldn't be drifting that far.

EXAMINER LOWE: Who asked you to move the well?

THE WITNESS: In this case it was Lewis Energy, but we work with all the operators to make sure we place the well so there is no collision.

EXAMINER LOWE: That's all the questions I have.

THE WITNESS: Yes.

EXAMINER LOWE: Thank you.

MS. BENNETT: May I ask a follow-up question?

EXAMINER McMILLAN: Certainly.

MS. BENNETT: I'm looking exhibit, what is BC & D's C-108 with the flat Azimuth from my materials, and I've highlighted a few items for Mr. Duncan to review based on a question from Mr. Larson. And these relate to the plans to inject the maximum amount that BC & D sought for injection, so I've highlighted a few excerpts for Mr. Duncan.

REDIRECT EXAMINATION

BY MS. BENNETT:

Q. And the first one is on the -- it's the third

page behind the administrative checklist, and it has a number of items outlining what BC & D is seeking, and that checklist or that list of items it says what BC & D's maximum proposed injection amount is per day. And what is that?

A. BC & D sought approval to inject 15,000 barrels per day.

Q. And this, if you turn to about ten pages in, there is a Notice of Publication.

A. Uh-huh.

Q. And on the Notice of Publication how much does BC & D seek. It's about ten pages into the document.

A. BC & D sought to inject 15,000 barrels per day.

Q. And that's what date?

A. And that's in the publication.

Q. What they put in the publication?

A. Yes.

Q. And then if you turn to a few pages back, there's what's called a summary checklist, an administrative summary checklist that the Division prepared?

A. Yes.

Q. And do you see from here the bottom?

A. Yes.

Q. That is says --

A. Maximum injection rate of 15,000 barrels per day.

Q. That's down towards the lower one-third of the form; right?

A. Yes.

Q. Could you point to that on the form for the Examiner, where that is? Could you like physically turn the page?

A. In the ADR Hydraulic and Geology Information, or AOR, sorry, hydraulic -- hydrogeologic -- I can't say that -- and geologic information disposal injection rate 15,000 barrels per day.

Q. So it's unlikely, based on what we have in front of us, that this well has been or will be -- it's not permitted to operate at 50,000 per day?

A. No.

Q. And earlier you were asked some questions about the potential for interference between the Jal and the BC & D well, and it's your understanding that the BC & D well isn't currently injecting, although it's approved to inject, but it's not currently injecting in the Devonian; is that correct?

A. That's correct.

Q. And the NGL is supposed to inject into the Devonian?

A. Yes. I can say without modeling that if the injection rate of BC & D well is 15,000 barrels per day over that 7000 foot interval, it probably will not interfere. And in a moment you can ask Scott Wilson.

Q. A moment ago you testified that you were worried about the potential for induced seismic based on the lack of mechanical integrity and the potential to -- for fluids to communicate to the Ellenburger. That has nothing to do with how close the well is based; correct?

A. That's correct.

Q. It has to do with the mechanical integrity and the protections in that particular well?

A. Yes.

MS. BENNETT: Thank you.

MR. LARSON: I have a follow-up question.

EXAMINER McMILLAN: Go ahead.

RECROSS-EXAMINATION

BY MR. LARSON:

Q. Mr. Duncan, referring to Exhibit 1, which is administrative order SWD-1482, is there a provision in that order that limits the daily injection rate for BC & D? You might have to look through it.

A. I do not see it. I would also note that the orders don't always include all the policies.

Q. What's the Division policy?

A. On injection rate, I don't know. I'm not an expert in all their policies, but it's noted there is 15,000 barrels per day injection.

Q. It does have a maximum surface pressure, doesn't it --

A. Yes.

Q. -- in the order, but no limitation on daily injection?

A. Not in the order itself.

Q. And if I understood you correctly, you believe that BC & D is not currently injecting into the Devonian?

A. According to the records, no C-101 has been filed that shows the work has been done. But you presented me with an approved notice signed by Maxey Brown, but -- that's on a C-103, but there is no C-105 in the state's records indicating that the work was actually carried out.

Q. Understood. Thank you.

EXAMINER McMILLAN: Just tell you, I am taking a quick look at SWD-1482, and do you know if BC & D ran cement as required in this order?

MR. LARSON: I do not know.

EXAMINER McMILLAN: Will you check, check into that?

MR. LARSON: Okay.

EXAMINER McMILLAN: And then I guess let's also check, find out what the current injection interval is right now of BC & D. Do you have any objections to that?

MS. BENNETT: No.
EXAMINER McMILLAN: Okay.
MR. LARSON: Can I provide --
EXAMINER McMILLAN: Yeah, as long as you provide it to everybody.
MR. LARSON: Of course.
EXAMINER McMILLAN: No objection to that?
MS. BENNETT: No. Sorry.
EXAMINER McMILLAN: Just want to make sure.
MS. BENNETT: If it pleases the Examiner, I do have the information about how what the difference is between the original application and new application, and it turns up the change in location and proximity, the old distance is 6453 feet and the new application is 6206 feet but even 6250 -- 6050? Is that what you said?
MR. LARSON: That was the calculation.
MS. BENNETT: So it's between 200 and 400 feet closer.
MR. LARSON: I don't know how he did the calculation, I just received that information. I think it's accurate to say it's in a range 200 to 400 closer.
THE WITNESS: 1.2 miles.
EXAMINER McMILLAN: Okay. Anything else?
EXAMINER LOWE: No.
MS. BENNETT: Thank you. With that I would like

to call my next witness.

EXAMINER McMILLAN: Let's just -- okay, so BC & D had Exhibits 1 and 2.

MS. BENNETT: Uh-huh.

EXAMINER McMILLAN: And we aren't -- are you going to accept those as part of the record?

MS. BENNETT: Yes.

MR. LARSON: I would -- they are both public record documents, they're OCD documents. With that in mind, I request the admission of BC & D B Exhibits 1 and 2.

MS. BENNETT: No objection to BC & D Exhibit 1 is the same exhibit that I included in my packet of materials as the administrative order.

MR. LARSON: It's redundant.

MS. BENNETT: So no objection.

EXAMINER McMILLAN: So Exhibits BC & D Exhibits 1 and 2 may now be accepted as part of the record.

(Exhibits BC & D 1 and 2 admitted.)

EXAMINER McMILLAN: So let's come back at 10 o'clock, and we will give the attorneys a chance to get back.

MS. BENNETT: Okay. Thank you.

(Recess taken.)

EXAMINER McMILLAN: Call the hearing back to order. Leonard has some questions he wants answered.

EXAMINER LOWE: I have a question.
MS. BENNETT: Okay.
EXAMINER LOWE: The application here, I'm trying to catch up to where we are at on this -- SWD-1328 has an existing API number; is that correct? Or the old --
MS. BENNETT: 1428, sorry, what are you looking at?
EXAMINER LOWE: The -- I wrote it on my notes.
MS. BENNETT: Oh, sorry, right. Yes, SWD-1328 is the reapplication of BC & D based on the -- and I'm not trying to put words in your mouth, so feel free to correct me if I'm wrong, but my understanding is the BC & D well was maybe proposed as an SWD by another operator, and then Mr. Hill acquired it and reapplied, so there was an SWD order that existed for this well for Unified.
MR. LARSON: It's a previous administrative order from 2012, I believe.
EXAMINER LOWE: Reference API Number 20 -- 30-025-25046, and the -- then there's another SWD reference in the Exhibit SWD-1482, what API is that associated with?
MR. LARSON: Okay. I'm looking at SWD-1328 dated April 12, 2012. That shows API 30-025-25046, and then SWD-1482 has the same API number, 30-025-25046.
EXAMINER LOWE: And on the current situation that's happening now, is there a new API number for this

well?

MS. BENNETT: Well, the Cobra well is not yet permitted. The API number that you are referring to and that Mr. Larson is reading off is the API for the BC & D well, not the NGL proposed well.

EXAMINER LOWE: There's not an API number now?

MS. BENNETT: Not that I'm aware.

EXAMINER LOWE: Thank you. Pass.

EXAMINER McMILLAN: I just wanted to make sure your question was on the record.

EXAMINER LOWE: Thank you very much.

MS. BENNETT: Thank you. With that I would like to call my next witness, who is Dr. Kate Zeigler.

KATE ZEIGLER

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Good morning, Dr. Zeigler. How are you today?

A. I'm fine. How are you?

Q. I'm fine, thank you. Would you mind stating your name for the record, please?

A. Kate Zeigler.

Q. And for whom do you work?

A. Zeigler Geology and Consulting on behalf of NGL Water Solutions Permian.

Q. What are your responsibilities?

A. I'm a geologist, and so I work on developing cross-sections and understanding the stratigraphy and geology of the basin for NGL.

Q. Thank you. And are you familiar with the application filed by NGL in this case?

A. Yes, ma'am.

Q. And are you familiar with the drilling plans for the well that we are here in this hearing?

A. Yes.

Q. Have you conducted a geologic study of the area embracing the proposed location of the well?

A. Yes.

Q. Have you previously testified before the Division?

A. Yes.

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

A. Yes.

Q. And you have prepared studies like the one we are going to talk about today for NGL's prior cases; is that right?

A. Yes.

Q. And those studies have been submitted to the Division in support of NGL's prior applications; is that

right?

A. Yes.

MS. BENNETT: At this time I'd like to tender Dr. Zeigler as an expert in geology matters.

MR. LARSON: No objection.

EXAMINER McMILLAN: So qualified.

BY MS. BENNETT:

Q. Dr. Zeigler, turn to Tab 2, please, in the materials. And could you briefly explain to the Examiners or give them an overview of what's in Tab 2?

A. Tab 2 being?

Q. Tab 2 should actually be --

A. Oh, there's a second tab. It's the second Tab 2. This is a set of exhibits that I prepared on behalf of NGL that includes an overview of the stratigraphy of the area, as well as cross-sections and several Isopachs for the deeper part of the different sections.

Q. The first page is the stratigraphic chart for the Delaware basin from Broadhead?

A. Yes, ma'am.

Q. Let's walk through that really quickly for the Examiner.

If you could first speak from the key feature at the top working down and give a brief overview of each of the features as you work down that chart, that would be

helpful.

A. So what I've done here is taken Ron Broadhead's 2017 overview of the geology of the Permian Basin, and using reference wells in the area have constructed a representative stratigraphic diagram for the area just to make sure that we are all on the same page in terms of our geologic nomenclature for the area because there are various, at times, confusion between driller lingo and geologist lingo, and so just try to keep it all straight as we go through this.

So working from the top down, the youngest strata that we will encounter when we drill through this area are the Wristen and Chinle and they are Triassic in age.

And sitting below that is the Upper Permian, in this area mostly the Rustler and down into the Salado and Castile. And it's in this upper 400 to 700 feet or so that we get the fresh water resources in this part of Eddy and Lea County. And the fresh water resources out there are not great, and their quality, not great, and their quantity that they are in that upper 4- to 700 feet.

As we go down, we move to the Permian down into the Delaware mountain group where there is petroleum production both historic and current. And then moving down into the Bone Spring and the Wolfcamp, also historic and current production.

As you go on down to the Pennsylvanian, we'll encounter some of the units that were mentioned earlier for the potential injections, the Strawn, Atoka, Morrow, Barnett and on down. And as we come down into the Devonian -- and this is where sometimes the geologic lingo and the driller -- historic driller lingo tend to separate from one another, is what I, as a geologist and stratigrapher, would call the Devonian is the Woodford and, where present, the Thirtyone formation, which is not always present in Southeastern New Mexico, and that's simply an age designation.

Many drillers use the term "Devonian" to refer to the Wristen and sometimes the Fusselman as well, so sometimes there's a disconnect between what's called the Devonian for myself as a stratigraphic purist. So from here on out I will attempt to stick with driller lingo.

So we arrive, as we go down a section, we arrive at the Woodford Shale, which is the upper permeability barrier for target injection interval that NGL is interested in.

Below that we have, where present, the Thirtyone formation, the Wristen group and the Fusselman and the Montoya. And below that the Simpson group, which is middle Ordovician, which is going to act as a lower permeability barrier to the injection interval that NGL is interested in.

And then on down to the Ellenburger where present is sandstone in Cambrian and Precambrian.

Q. So there is a permeability barrier above and below the target injection interval?

A. Yes, ma'am.

Q. Let's turn to the next few pages of your exhibit, and can you explain briefly what these next few pages are?

A. So these are a series of Isopach maps that were developed from the Bureau of Economic Geology, Texas Bureau of Economic Geology data sets, as well as data sets from New Mexico Bureau of Geology from Ron Broadhead. And so these show the location of Cobra, and there are two figures for each Isopach map.

There's one that simply shows Cobra on its own. The purple lines are the Isopach lines. The blue and the green lines are estimated locations of fault zones in the area. And we've chosen to show those in two different colors because the Precambrian fault in blue, these are coming from Ron Broadhead's compilation of data from the entire Western Permian Basin, and then the green ones are coming from the Bureau of Economic Geology maps that have been developed over time, so we chose to show both so we are showing all potential fault locations that may be in the area.

I should note that in the years that have passed since a lot of these faults were -- positions were estimated, that better well control in the area has shown that a lot of these predicted fault locations are not accurate. So we're honoring the data that's in these big data sets, but I think a lot of work needs to be done to refine exactly where the fault locations are.

So the first image in the each Isopachs is just the well location. And then the second one shows the line of cross-section on that same Isopach, so I tried to lessen confusion by just showing the well on the Isopach and the well with its cross-section and reference wells so you can see in space where everything sits.

So we are going to start now at the bottom of the section and go up. So we are starting in the Ellenburger looking a little over 500 feet thick or so, estimated thickness for the Ellenburger, and you can see the line of cross-section, the wells that we have chosen to show where Cobra would sit.

And then as we move up a section, the Simpson group, looking at 850 to 900 feet thickness of the Simpson group.

Q. That's one of the permeability barriers; right?

A. Yes. This is one our permeability barriers. It can be anywhere from 40 to 60 percent mudstone within that whole section, so it can act as a quite reasonable Permian barrier.

Continuing on up to the Montoya, which is a little bit thinner, looking at 320 or so feet thick for the Montoya, combined Wristen and Fusselman, at this point no one has attempted to separate those stratigraphic units from an Isopach perspective.

So here looking at significant thickness of the Wristen and Fusselman combined, this also would take into account any Thirtyone formation if it's present in the area. So looking at approximately 1700 feet thickness for the -- that would be the target injection interval.

And then above that, Woodford, showing here about 280- to 300-foot thick Woodford Shale, and above that would sit the Mississippian Limestone which is the next Isopach above that showing approximately 300- to 350-foot thick for Mississippian Limestone sitting above the Woodford Shale.

Q. Thank you. And then the next exhibit in your packet is the cross-section that you created from the well data identified on the line cross-section in your Isopachs.

A. Uh-huh.

Q. And can you briefly explain to the Examiners this exhibit?

A. So what we did here was we took well log data that was available to us through the Oil Conservation Division website and focused on wells that were deep enough to show from the Mississippian Limestone through as much as the Devonian -- and here I'm going to switch to driller lingo for the Devonian -- to show not only the thicknesses of NGL's target injection interval, the thickness of the Woodford Shale and the Simpson, but also to show that -- and this occurs if you look at the Isopachs as well, that in the area where Cobra is located, we don't see evidence of offset between wells that would suggest that there are structural features such as faults that are very close to where the proposed Cobra well location is.

Q. Thank you. Based on your studies and your review of the materials, in your opinion, will the drilling of the Cobra well impact the correlative rights of mineral interest owners?

A. I don't believe it will with the given -- the upper and lower permeability barriers.

Q. How about in the injection zone, is there any productive shale in the injection zone?

A. There is none that have been identified as economically viable. If there are any isolated traps, it would take some pretty significant 3-D seismic imaging to locate them in a way that would make them worth targeting.

Q. And we talked a bit earlier in the start of your testimony about how far up the fresh water resources are. In your opinion, is there a risk to the fresh water

resources if the Cobra well was drilled?

A. No.

Q. And is that again because of the depth difference and the upper permeability barrier?

A. That, and there are also a number of other permeability barriers in the upper part of the section that act to additionally help constrain fluids from the fresh water resources.

Q. A moment ago you discussed the fact that you could look at these and see if there was faulting nearby the proposed well. Are there any faults more generally in this area?

A. If you look at any of the Isopach maps where we've show the faults compiled by Ron Broadhead and the Bureau of Economic Geology, there are faults that are documented as part of the western edge of the central basin platform over towards Jal, so five to six miles to the east of the proposed location. And there is a projected fault about five or six miles to the west of this location, although, how confident we feel about the exact location of that fault is not well constrained at this point.

Q. So, overall, what are your conclusions from the cross-section that you prepared of the Isopachs and the charts that you prepared in terms of the viability of this injection zone as well as the permeability barriers?

A. It's my estimation that not only is there a reasonable thickness of appropriate type for injection in what we are calling the Devonian, quote-unquote, the Fusselman and uppermost Montoya, and that injection interval is a fairly consistent thickness throughout this area, and it's separated both above and below by reasonably thick permeability barriers, the upper being Woodford Shale, the lower being the Simpson group. And that the Woodford Shale, the upper permeability barrier, along with other shale bearing above it also act to protect the fresh water resources at the very top of the section.

Q. Thank you. Were the exhibits behind Tab 2 created by you or compiled under your direction and supervision?

A. Yes, ma'am.

MS. BENNETT: At this time I would like to move the admission of the Tab 2 exhibits.

MR. LARSON: No objection.

EXAMINER McMILLAN: Exhibit 2 may now be accepted as part of the record. Cross?

(Exhibit NGL Tab 2 admitted.)

CROSS-EXAMINATION

BY MR. LARSON:

Q. Good morning, Dr. Zeigler.

A. Good morning.

Q. Were you in the room when Dr. Duncan was testifying?

A. Yes, sir.

Q. And we were talking about the proximity of BC & D's well to NGL's proposed well and the potential issue of interference.

A. Yes, sir.

Q. Are you aware of any geological formation that would act as a barrier horizontally and prevent interference between the two wells?

A. In terms of which injection interval?

Q. The Devonian.

A. They should be laterally continuous.

MR. LARSON: Thanks.

EXAMINER McMILLAN: First question, I would like for your displays, can you label what the different formations are?

THE WITNESS: So it's down in the legend, but we can certainly change it to put the --

EXAMINER McMILLAN: Yeah, that would be more --

THE WITNESS: Yes.

EXAMINER McMILLAN: And how thick do you think the Woodford is going to be?

THE WITNESS: So in looking above the Isopach, and actually this well, the West Jal B Deep Number 1, between the estimated thickness from the Isopach and looking at the West Jal B Deep as the potential reference well, we are looking at 250 to 400 feet thick for the Woodford in that area.

EXAMINER McMILLAN: And you have the -- okay, I'm sorry. So you say this is a shale?

THE WITNESS: It's at least 45 to 50 percent shale in this area. It is a mixed unit. It is lithologically heterogenous of sandstone and shale.

EXAMINER McMILLAN: And it in fact is a barrier?

THE WITNESS: Yes.

EXAMINER McMILLAN: So how thick do you think the system will be?

THE WITNESS: So between the reference well, again the West, West Jal B Deep and the Isopachs, we are looking at a Simpson that is probably around 800 feet thick or so.

EXAMINER McMILLAN: And also the Montoya, the Montoya is a dolomite; right?

THE WITNESS: Yes, sir.

EXAMINER McMILLAN: And it's impermeable?

THE WITNESS: Generally speaking it's considered a pretty tight unit.

EXAMINER McMILLAN: How thick will that be?

THE WITNESS: Between the reference well and the

Isopachs, we're looking at approximately 400 to 500 feet thick for the Montoya, so that would add to the permeability barrier below.

EXAMINER McMILLAN: So there's 12- to 1400 feet of barrier beneath the injection interval?

THE WITNESS: Combined, if we are going to combine the Montoya with the Simpson Group.

EXAMINER McMILLAN: You're going to have 250 -- the Woodford is 300 feet thick?

THE WITNESS: Approximately.

EXAMINER LOWE: I just had a question on your stratigraphic chart.

THE WITNESS: Uh-huh.

EXAMINER LOWE: What did you mean by fresh water resources?

THE WITNESS: So I'm looking at basically what the EPA would call at maximum livestock quality water. So that can -- that can have total resolve solid and salinity contents that are a little bit greater than what human drinking water consumption levels would be, but I was looking at what would be considered your total resolve solids in the range of the 1000s to 1200 parts per million for livestock quality. Because the majority of critters that are drinking in that area are livestock, and so most of the wells that would be targeted in that area are going to be livestock wells as opposed to domestic or municipal water.

EXAMINER LOWE: Would you mean like protectable waters --

THE WITNESS: In terms of the State Engineer designation?

EXAMINER LOWE: Yes.

THE WITNESS: Uh-huh.

EXAMINER LOWE: And approximately what's at the bottom of that fresh water resource?

THE WITNESS: If you are lucky, you can get, fresh water, quote-unquote, resources down to about 400 feet or so, but then it starts getting pretty brackish and the water quality drops off pretty significantly the further down you go.

EXAMINER LOWE: So would there be a fresh water aquifer in the area?

THE WITNESS: Uh-huh, what the state year would consider the groundwater resources which would include Ogawala, Santa Rosa, and Rustler. Those are your three primary aquifer-bearing units out there.

EXAMINER LOWE: That's all I have. Thank you.

EXAMINER McMILLAN: I don't have any more questions.

THE WITNESS: Thank you.

MS. BENNETT: Thank you.

At this time I would like to call my next witness, Mr. Todd Reynolds.

TODD W. REYNOLDS

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Good morning, Mr. Reynolds.

A. Good morning.

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

A. Todd W. Reynolds.

Q. For whom do you work and in what capacity?

A. I work for FTI Platt Sparks. We are a consulting firm in Austin, Texas. I'm managing director, and my background is geology and physics.

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

A. Yes, I have.

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

A. They were.

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

A. Yes, I am.

Q. Have you conducted a fault slip probability analysis related to this application?

A. Yes.

Q. Have you prepared similar studies for NGL's prior applications?

A. Yes.

Q. Were those studies submitted to the Division in support of NGL's application?

A. They were.

MS. BENNETT: At this time I would like to tender Mr. Reynolds as an expert in fault slip probability analysis.

MR. LARSON: No objection.

EXAMINER McMILLAN: So qualified.

BY MS. BENNETT:

Q. Mr. Reynolds, let's just start, for a moment, with an overview of what the Stanford University Fault Slip Probability Tool is. Can you describe that for the Examiners?

A. Sure. It's a software tool that basically incorporates a number of factors to assess the potential or probability that a fault could possibly slip if there is increased pressure associated with injection.

And some of the things that are considered and some of parameters and inputs are injection volumes, historical, so that we know how much water has gone into the ground prior to running the model, and then future injection volumes that you anticipate to be in the area. That would be one of the factors.

Another factor is the reservoir, the thickness of the reservoir, the porosity, the permeability of the container that you are putting the water into.

Another input factor is the location of any faulting in the area. And there is a number of factors important about the faults, the utmost of which is the orientation of that fault. Does the fault orient in a line itself in a direction somewhat parallel to maximum horizontal stress, or is it 90 degrees off from that. So if a fault is 90 degrees off from that maximum horizontal stress direction, it's very unlikely to slip. It takes tremendous pressure to cause that slip and, conversely, a fault that's somewhat parallel to that orientation would be more likely to slip.

So those are all factored into the model, as well as dip angle of the fault. That's another factor that can cause a fault to slip very easily. A 60 degree fault dipping is the most critically stressed high fault. A near vertical fault, which is common to this area, is much less likely to slip.

So those are some of the factors that are built into the model, as well as viscosity and other factors.

Q. And you collaborated with Dr. Zeigler in terms of this data input that you used in your modeling?

A. Yes, both collaboration and independent analysis, building cross-sections and looking -- doing structural mapping to determine if there is any significant faulting in the area.

Q. Great. Well, let's look first at Exhibit A behind Tab 3, if you wouldn't mind turning to Tab 3. And Exhibit A is -- well, what is Exhibit A?

A. Exhibit A is a diagram that was sourced from the USGS Earthquake Archive website. And what it shows is it just tries to demonstrate and show the differences in, in magnitude of earthquakes. Generally there are much higher frequency of small earthquakes as you look at this chart. Below a 2.0 magnitude there is over a million earthquakes that have that magnitude. And as you get even lower than that, the number is, is in the tens of millions of small earthquakes, one and a half, 1.0. And then as the magnitude increases, the frequency of those types of earthquakes diminishes.

And also to point out that typically earthquakes are felt by humans around the 3.0 level. And so anything typically below a 3.0, it's only recently that we even knew they were occurring. Once more monitoring stations were established, we can see that there are -- there are these small earthquakes that were probably going on even prior to the installation of these monitoring systems.

Q. Now, let's turn to Tab B behind the next tab, Tab B, and this is an -- a study, right, prepared by Mr. -- or Dr. Steven Taylor, cataloguing seismic activity within 50 kilometers of the Cobra well?

A. That's correct.

Q. And you have worked with Dr. Taylor before, haven't you?

A. Yes, we work together, and he passes along this type of information for me to incorporate into my maps.

Q. And Dr. Taylor has testified before the Division before?

A. He has.

Q. If you turn to Page 2, the second page of his exhibit, there is Table 2 that says, "New Mexico Area Reporting Period Seismicity." And, as I understand it, this is evidence or this is data that he's collected from the seismic monitors that he has in place. Is that your understanding of this as well?

A. That's correct. So this would be an example of events that if not for the NGL monitoring system, we wouldn't even know they occurred because USGS had not picked up any of these events, and that's -- that's one area where

NGL seemed proactive is they actually put in monitoring stations out in a broad enough area that they can monitor most of their activity.

And what you see on this chart is dates and times for the events, latitude-longitude of those events, and then next to the last column over to the right would be the magnitude. So you can see that the largest one that they have detected so far was just under a 2.0.

And even here there is still going to be some uncertainty because the monitoring stations are fairly far apart. There is going to be some, not only lat-long uncertainty of the events, but even greater uncertainty on the depth.

Q. Okay. Thank you.

A. But a much greater accuracy than the USGS because their systems are even further apart.

Q. And a minute ago you said the USGS doesn't even report under 2.0?

A. Well, it's not that they don't report it, it's just that the systems are spaced so far apart they don't detect it.

Q. Okay. And then the next few pages of Dr. Taylor's study shows where the Cobra well is in relation to the seismic monitoring locations that Dr. Taylor has installed; is that right?

A. Yes. The next page is Figure 1. This shows where the NGL monitor -- seismic stations are, the yellow push pins, so they have three others down in Reeves County on the Texas side.

Additionally he is showing some -- I think there are locations for either the Texas monitoring system, the green ones, and New Mexico Tech, I believe, are some of the green push pins.

Figure 2 -- Figure 1 didn't have the Cobra on it, but Figure 2 does show the Cobra. And on here we are showing with the red dots the location of the historic USGS seismic points or seismic events that have been recorded in the area.

And, again, you see the blue push pin for the Cobra. There are no historical events within what I would consider the area review, and we typically look 100 square miles around the well. And there is nothing within that radius of the well historically.

Figure 3 would be the events that had been the -- the 13 events that were listed in that table that have been recorded on the NGL system and shown by the red dots. And I believe one of those may just barely be in an area of review. We can look at that a little closer on one of my maps that will come into the record.

Q. Great. Thank you for walking us through that.

Let's turn to Tab C now. And behind Tab C is your fault slip probability analysis; is that right?

A. Yes, that's correct.

Q. What are the first few pages of Tab C?

A. The first few pages basically walk through the exhibit and sort of explain the process. We can kind of skip that and go straight to the exhibits and I will walk through the exhibits, might be the easier way to do it, certainly in the record that will be read later.

Q. Great. That sounds good. Let's go ahead and do that and skip right to the heart of it.

A. So if you go to about four pages in, there is a key, that's Exhibit 1. This is just general information and the data showing the well name, top and base injection depths. We calculate mid injection depth because that's the depth we use to put into the model.

Estimated other parameters, water resistivity, formation temperature, et cetera, those all go into deriving the viscosity of fluid, compressibility to formation of fluid. Aquifer thickness, what I do is take one -- I take 50 percent of the injection interval, based on log analysis in the area that seems to be a, a general porosity development over that gross interval. So I use 50 percent of the designated interval as being porous injectable rock. A very conservative 5 percent porosity and 20 percent -- 20 mD perm, and then the stress gradients are either calculated from logs or derived from the Snee/Zoback paper that was published for this area.

We assume an initial pore pressure of .46, a normal pressure gradient. And then the Azimuth of maximal horizontal stress is shown here. The fault dip angle is assumed to be 85 degrees near vertical. And then we also put a, based on the .2 psi per foot, a max injection pressure or a max Delta P at the wellhead or at the bottomhole of the well.

So if, if I run the model at 50,000 or 40,000 barrels a day or whatever, and it goes above that number, then the volumes need to be ratcheted back because they would be limited by the pressure that you're allowed to inject anyway.

Q.   And just as a reminder, the .2 psi per foot a regulatory requirement?

A.   That's correct.

If we go to Exhibit 2, this shows the location of the wells that were input into the model. The red squares represent a number of proposed or pending NGL locations, so they are all factored into the model for this particular application, the subject well.

There's the well just to the northeast with API 25046 that was discussed at length earlier today. And then there are two other existing injection wells, one to the northeast at 27085 API, and one to the southwest at 42355 API.

And then the one seismic event that manages to barely creep into the area review, and it really wouldn't be in the area review of the Cobra, I've just included the area review for Thunderbolt, Raptor and all of them for running the model since you really need to look at all of them together, that one seismic event is out there at that location marked F12.

So -- and then to the east we see the fault segments, that are the BEG fault segments. It's important to segment the faults because the FSP software basically calculates a pressure at the center point of each segment, so just drawing it as a single line and putting in a center point that's not near the subject wells wouldn't be a valid examination.

So map one is basically the input data, the faults, the orientation of faults and the wells.

Q. And these faults that you outlined on here, that you have identified on here are faults that you previously examined in prior NGL cases?

A. Yes.

Q. So these are relatively well-known -- I mean, as far as you can know them, you have studied -- you've run

fault probability analysis for these same --

These are same the faults, correct. And there is also one other well put in the model. It's kind of sandwiched in between all those faults, 43360 is showing up with a yellow triangle, so that well was modeled, included in the model also.

FSP Exhibit 3 shows where we derive the direction of maximal horizontal stress. The arrow points to the area and we are seeing it be about 75 degrees east of the north there. This exhibit is taken out of the Snee/Zoback paper.

Exhibit 4 shows how we derive the viscosity in the area based on the bottomhole temperature and the resistivity of the fluid and the estimated salinity.

Exhibit 5 is the beginning of the fault slip potential software. And so this first half shows where the wells are located that we discussed in Map 1. Cobra is shown with the arrow and the "Co" denoted next to the well. The BC & D well is the well with a number "1" next to it. And then the fault segments off to the east are shown by the black lines on the map in the center of the page.

On the right-hand side is the injection volumes that were input into the model. The Cobra injection volume was put in at 40,000 barrels a day, and any existing wells were put in at their last current rate and then held flat moving forward.

And then that Number 8 well out there, which is a pending well, was input at 30,000 barrels a day. Now, having looked at a lot of wells out in this area, I know that everyone is asking for these high rates, but I'm not seeing many wells that are really capable of that, so it's somewhat invalid to run the model at a huge rate.

But anyway, we did run it at 40,000 barrels a day for the subject well, 30,000 for some of these others, and then what the wells show that they can inject and hold that moving forward for the existing wells.

Q. So you held the injection rate constant for 25 years?

A. Which is another thing that's very conservative. You would not expect those wells to inject constant rate for that long a period of time. You can expect them to decline off, which would even lower the possibility of fault slip. We are running it at kind of a worst-case scenario.

FSP Exhibit 6 shows the fault segments that were included in the model and their associated fault number just to be able to keep track of them, 1 through 13, I believe.

On this page, the color that the fault is represents its, its potential to slip. The green ones are the ones less likely to slip. And you see the color bar down below it shows that you are up in the 4000 pound range to it -- for slip to occur on these faults. And that's based primarily because these faults are oriented almost 90 degrees from the direction of maximum horizontal stress, which is 75 degrees east of north, so that factor alone makes these faults very unlikely to slip.

The next page shows each of those fault slip segments and the calculated pressure, Delta P increase that would be needed to initiate fault slip, and as you can see it's quite high. There is one fault in there that's, I think, segment 12 that's at 4300 pounds, 43, 41 over on the far, far side, and that's where one of the wells is in the model. That's not an NGL well. I'm not sure who it is, but it's a well located over there.

Exhibit 8 shows the fault slip potential for all the 13 fault segments. If you look at the center of the graph you see one kind of sitting apart from the rest that shows when you put some variation in the inputs, there is a 10 percent chance that that fault could slip as low as 3500 psi, but if the inputs are fixed, it's the 4300 pounds that I quoted here earlier. So this, this graph illustrates the effect of varying the inputs somewhat.

Exhibit 9 is the beginning of sort of a pressure plume or a pressure cloud that you would see associated with the injection wells, and so Exhibit 9 is the year 2025, January 1, 2025. And you see values next to the faults, that would be the Delta P increase at each of the fault segments.

And then there is one segment that is placed right at the well, not necessarily to represent a fault, but in order to calculate the pressure right at the well, we have to put the segment there because that's the way the software works.

So the one fault that you see on the pressure plots over in the upper right-hand corner that is considerably higher than all the rest represents the pressure at the well over these periods of time.

Q. And that's purely just for purposes of modeling?

A. Exactly. So Exhibit 10 was the year January 1, 2035. As you would expect you see some pressure increases along the faults off to the east. We are still talking about tens of pounds up to 178 pounds, I believe, is the highest at that point.

And then we run the model on out to 2045, January 1, 2045 with Exhibit 11. And at this point the most critical fault, which was fault Segment 12, has reached 195 pounds, so still well below that 3500 or 4300 that might initiate a fault slip. And as you look in left-hand column all the faults are still green and all still in zero percent fault slip probability.

Exhibit 12 is just a recap of all the fault segments showing the calculated pressure to initiate slip along that fault segment, and then the Delta P that's calculated to be at that fault at the end of the model at 2045. And as you can see, they are all well below the value that would initiate fault slip.

Q. And so to summarize, your study concludes that there is very low likelihood of fault slip based on adding the Cobra well even when injecting at 40,000 barrels per day?

A. That's correct. Simply primarily because the orientation of the faults would not -- well, there is two factors; one, those faults are quite a distance away. They are, as you look at the map again, so distance is your friend in one aspect, they are quite a distance away, approximately four miles away to nearest fault. And then the other is the orientation that they are almost 90 degrees rotated from the direction of maximum horizontal stress, which makes for extremely high pressures to initiate fault slip.

Q. And so it's your opinion that there's very little concern for induced seismicity based on the addition of the Cobra well?

A. That is my opinion. There has not been any historical seismicity in the area, and part of that is there is no fault right in the area. And the faulting that is there is not the type of faulting that would be extremely worrisome.

Q. Thank you. Were the exhibits behind Tab 3 prepared by you or compiled under your direction and supervision?

A. They were.

MS. BENNETT: At this time I would like to move the --

Q. Did you rely on Exhibits A and B when you prepared your -- or in developing your conclusions which are the USGS --

A. Those Dr. Taylor's --

Q. Yes.

A. They are incorporated into the model, and they are so distant from the area of review that they really don't come into play.

Q. Okay.

MS. BENNETT: With that, I would like to move the admission of Tab Exhibit -- the Tab 3 exhibit.

MR. LARSON: No objection.

EXAMINER McMILLAN: Exhibit 3 may now be accepted as part of the record. Cross?

(Exhibit NGL 3 admitted.)

MR. LARSON: No questions.

EXAMINER McMILLAN: Okay. What is the relationship between the vertical and horizontal permeability in the Devonian?

THE WITNESS: I don't know that we know if there is a significant difference between the two. I mean, the permeability that's input into the model is just a general perm.

EXAMINER McMILLAN: So you did not --

THE WITNESS: It's not factored into this model.

EXAMINER McMILLAN: Would you expect to see any difference in the permeability between vertical and horizontal?

THE WITNESS: Natural fractures would certainly enhance vertical permeability over the horizontal permeability, but just the native rock, no. I wouldn't expect to see a lot of differences in just the matrix.

EXAMINER LOWE: I have a few questions.

On Exhibit 2 where it indicates your seismic location, in reference to the Cobra well, I guess, the closest red dot, approximately how far is that away?

THE WITNESS: So on Figure 2 we are dealing with the USGS located points, and it would look like that one in Northern Winkler County, Texas, would be the closest one. But as far as how far that is, let me look at my map. I don't think my map gets as far as Winkler County, so it's going to be considerably outside the hundred mile square area.

MS. BENNETT: Can you say it's something like seven, ten, or 15, can you like hypothesize how far?

EXAMINER LOWE: The scale he has, it says 38 kilometers, and I'm suspecting maybe 20 kilometers is the closest one-ish.

THE WITNESS: Yeah. So my map on Map 1 does not quite get over into that step-up panhandle of Winkler County, and that's over -- and that's already over 20 miles away at the edge of my map.

EXAMINER LOWE: Approximately 20 miles.

THE WITNESS: So it's probably 30 miles.

EXAMINER LOWE: Okay. And for your model that you indicated FSP, your data worksheet.

THE WITNESS: Yes.

EXAMINER LOWE: FSP Exhibit 1, I'm just trying to understand what all of this is.

THE WITNESS: Okay.

EXAMINER LOWE: I'm suspecting this is all your input?

THE WITNESS: It is.

EXAMINER LOWE: And everything else afterwards is your what? This is, what's reflected in maps and charts and so forth, what you are doing?

THE WITNESS: Yeah, all of these data inputs are variables that have to be put into the model.

EXAMINER LOWE: Okay.

THE WITNESS: Not particularly every one of them, but a number of those you have to know to calculate the viscosity.

EXAMINER LOWE: Okay.

THE WITNESS: Such as the resistivity, the formation temperature, the salinity, all of those go into calculating the -- the factors that go into the model are the mid injection depth point up near the top, the density, the viscosity, formation compressibility, fluid compressibility, the aquifer thickness, the porosity, the perm, the vertical stress gradient, the two horizontal stress gradients, the initial pore pressure of the reservoir that you are injecting the salt water into, direction of the horizontal stress, fault dip angle, and friction of coefficient for faults, all of those factored into the model.

EXAMINER LOWE: Okay. And that FSP Exhibit 1, where are the time frames in reference to your 2025 and year 2035, 2045 and different time frames? Is that part of this list here, or is that something separate entirely?

THE WITNESS: No. The models just run out 20 years. Those are just snapshots. I think if you look at some of the graphs from the snapshots you can see the pressure -- let's just go to one of those, maybe go to

2035. If you look at the -- the select fault to plot pressures graph in the upper right of Exhibit 9, that would be -- we're looking at at 2025 there on Exhibit 9 -- that green vertical dash line represents that point in time.

So if you bump, just bump that green line over year by year by year, you can read off the pressure on the faults, so there is just -- we take ten-year snapshots at 25, 35 and 45.

EXAMINER LOWE: As a side note of the exhibits that were submitted, example, for Exhibit A, all of these exhibits that we received from the OCD we have to submit and scan in and show to the world, and there's two areas, Exhibit A, and there's FSP Exhibit 4 seem to be a little blurry. And when we scan these, these items that are submitted to the world, I assure you we will be getting questions from the world asking us what this means when we can't, on our end, we don't have time to enhance that information.

So I guess just for future exhibits, to everybody, if you could make everything clear -- clearer, as much as you can, because we spend -- I spend a lot of time with people telling people what's meant by what we scan in, and we don't have time to explain all of that, so that's just a side note.

MS. BENNETT: Thank you. I appreciate that.

EXAMINER LOWE: That's all the questions I have. Thank you.

MS. BENNETT: Thanks. Before I call Mr. Wilson, I wanted to see if the -- I know there are a couple of other folks in the room who have quick cases to put on, and so before I called my last witness I wanted -- because it might take some time, I don't know how many questions you might have -- I wanted to offer the opportunity, if it's appropriate to allow the other folks to go, or I'm happy to just keep going.

MR. BROOKS: For everybody's information, my luncheon meeting that I usually have on Thursdays is not going to occur today, so I have a more flexible schedule.

MS. BENNETT: Then I think --

EXAMINER McMILLAN: Just keep going.

MS. BENNETT: Thank you. With that, I would like to call my final witness, Mr. Scott Wilson.

SCOTT JAMES WILSON

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Mr. Wilson, state your name for the record.

A. Scott James Wilson.

Q. For whom do you work and in what capacity?

A. I work for Ryder Scott Company on behalf of NGL

Water Solutions Permian.

Q. Have you previously testified before the Division?

A. I have.

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

A. They were.

Q. Are you familiar with application submitted by NGL in this case?

A. I am.

Q. Have you conducted a petroleum engineering study related to this application?

A. I have.

Q. Have you prepared similar studies for NGL's prior applications?

A. I have.

Q. And have those studies been submitted to the Division as part of NGL's prior applications?

A. They have.

MS. BENNETT: I would like to tender Mr. Wilson as an expert in petroleum engineering matters.

MR. LARSON: No objection.

EXAMINER McMILLAN: So qualified.

BY MS. BENNETT:

Q. Let's talk about the study that you prepared.

That's behind Tab 4; right?

A. It is.

Q. As I understand it, your study has two parts; right, a nodal analysis and a reservoir simulation?

A. That's correct. The first four slides involve the nodal analysis and the rest is a simulation.

Q. Can you briefly describe what a nodal analysis is and your conclusions from the nodal analysis that you prepared?

A. Yes. Nodal analysis is the technology where you couple the capacity of the formation to accept injected fluids along with the capacity of the pipes that deliver those fluids. And you take those two systems and set them against each other and identify the balance point where the actual injection will occur.

Q. And when you did the nodal analysis here, did you take into account the West Jal Deep well, or would that be more in the reservoir simulation?

A. The specifics to that well would be represented in the simulation work. The nodal analysis work is fairly generic for any wellbore at this depth and this formation.

Q. And so what is the reservoir simulation? What is a reservoir simulation?

A. Reservoir simulation is a system of grid cells where each cell represents a piece of the formation, and if you couple a multitude of those cells together, you can model pressure and fluid flow through the reservoir and represent future events and saturation and pressure.

Q. And that's the study that you undertook for this Cobra well?

A. Correct.

Q. And that's the part of your study that includes input from the West Jal Deep well?

A. Yes, it is.

Q. Add before we look over the exhibit, could you briefly summarize your conclusions of your nodal analysis and your reservoir simulation?

A. The summary of the nodal analysis is that on injection wells at this depth there is a significant benefit to using a larger pipe, you just experience a lower friction drop and lower waste of horsepower on friction drop. So that's the conclusion of the nodal analysis.

On the base conclusion of the reservoir simulation work, the pressures and saturations surrounding these wells due to the thickness of the formation and the porosity and the other parameters is such that over a 20 -- 20-year -- say 20-to-25 year life span they don't reach maximum injection pressures, so there is a high injection capacity in this formation.

Q. Thank you. Let's turn now to the pages of your

study, and can you sort of walk through those pages for the Examiners?

A. Sure. Exhibit 1-A is a classic nodal analysis plot. The Y axis shows the bottomhole pressure on injection while the X axis shows the total liquid rate injected. With the larger tubing size, that's the red curve there with the triangle, it shows that this well -- well, a typical well could potentially inject as much as 48,000 barrels a day because you were basically delivering all the pressure all the way to the bottom of the formation.

With the smaller tubing size, say you use five and a half, you can only inject 37,000 barrels a day, so that is in order of magnitude -- well, it gives a representation of the difference between those two tubing sizes.

So along the same lines, Exhibit A-2 is -- describes the total injected liquid rate along the Y axis. X axis shows the tubing ID, the average tubing ID. And there is two points there, there is one case where it was a large tubing size and another case where it was the smaller tubing size and basically the intersection points from the prior graph.

So here it says with the larger tubing size you can inject 48,000 barrels a day. The smaller is 37,000 barrels a day. The blue inset table shows if your larger goal is to inject say 400,000 barrels a day, in that area, it says if you are using a smaller tubing size, you will need 11 wells to inject that amount; whereas, you only need eight wells to deliver -- to inject that amount for the larger size tubing. That's Exhibit 2.

Exhibit 3 shows a little more detail on where the friction is used up on these various wells. The larger tubing size is represented by the orange curve where it shows the pressure difference based on different injection rates. And as the injection rates come up to 50,000 barrels a day, the frictional drop is still below 1000 psi, so you are not using up a lot of horsepower fighting friction.

The five and a half inch tubing shows roughly the double friction drop. In that case at 50,000 barrels a day, you are probably losing 1200 psi., So the horsepower loss there is significant. So that's Exhibit A-3. So that's actually the end of my nodal analysis.

Q. Great. We will go to the next few exhibits. What do they show?

A. The next set of exhibits are more aerially based. Exhibit A-4 shows the location of Cobra well in relation to other NGL wells in area and the West Jal Deep well. The area shown here is roughly 25 miles wide by 18 miles tall.

A. Okay.

Q. That's Exhibit A-4.

A. A-5 shows the geologic map as provided by Dr. Zeigler for the Cobra well. And you need to visually interpolate that there is a 1400 foot thick contour to the northeast and there's an 1800 foot contour to the northwest, so the Cobra well is roughly 1700 feet thick at that location.

Exhibit A-6 shows the first of the simulation grid exhibits. To get your bearings on these exhibits, this is that grid mesh, and this one shows depth. So the red color on the top of the figure is roughly 13,000 feet deep. The yellow color is 15,000 feet deep, and the green in the lower right-hand corner is more like 18,000 feet deep. So the depth of the formations are mapped to match up with the geologic work from Dr. Zeigler.

Now for scale, you can kind of look at each of the well locations, and knowing where they are, like the Cobra and the West Jal, you can kind of see the distance between those and know it's roughly one 1.2 miles.

Also, these grid cells are four miles per cell, so if that's helpful in terms of getting scale here, that's what those do.

Q. Four cells per mile?

A. Sorry, four cells per mile. All right. Also the fine grids, you see those patches where the little grids are tighter, those are put there to add more resolution to those specific wells. And those have double the spacing, so there those are fine cells, and they are eight cells per mile.

Q. And this does identify the West Jal B well; right?

A. It does. It's immediately to the northeast of the Cobra well.

The next slide or the next page is Page A-7, and the thickness here -- the goal of showing this image is it's a side view of the grid, and it shows the structural relief and the thickness of the formation.

There is an inset there that shows an additional detail from east to west of the thickness of the formation. It also highlights the location of the Cobra well in the fine grids.

Exhibit A-8 is the -- is the, again, the thickness of the formation. So the thickest section here is roughly 1800 feet, that dark blue color. The yellow color is 1400 feet, so you get a vision that the zone gets thicker to the southwest.

So the Cobra well is actually a very good location. It's in a thick formation. It's also kind of isolated if you look at the clusters of injection wells in the grid, and it's by itself except for four or five wells within a few miles.

Exhibit A-9 shows the initial pressures in the grid, and the pressures are set based on the hydrostatic gradients in the area. So I set the pressure at one location and rest of the grid it closes by itself based on the hydrostatic forces and capillary pressures and things like that.

Now, this image is at time zero, that's before any injection starts. So A-9 is before any injection. A-10 is after 20 years of injection. And flipping back and forth between those two images you can see the colors have changed moderately where there is a higher pressure around the areas of injection. It hasn't changed the entire grid. there are sections of this grid that remain at urgent pressure, but it does show where the pressure near the injector increase as you would expect them after 20 years of injection.

Q. And when you say that this is -- you sort of turned on the wells to model the injection here, the injection volumes, what volumes are you modeling?

A. For the wells in this simulation, I turned them all on at 40,000 barrels a day.

Q. And that includes wells that are proposed and wells that are active; right? You ran them both, all, all of the wells at 40,000?

A. That's correct. It takes a lot of work to, to basically enter the exact rates that each of these wells is actually performing, so I just took the worst-case scenario and injected 40,000 for each of them.

Q. And you input 40,000 per day for the West Jal Deep well?

A. I did. So Exhibit A-11 shows the saturations around these wells after 20 years of injection. And the word "saturation" is meant to represent the injected fluid saturation, so it's kind of tracking the area of influence of each of the wells over time.

And so after 20 years of injection, due to the thickness of the formation, you can see at the Cobra location it's only moved out five or six cells away from the center of the injection point. And again, the fine grid cells are eight cells per mile. You can see the West Jal on there as well, it's up in the kind of northern edge of that grid. They haven't really intersected each other yet at 20 years.

You go to A-12 is effectively the same image but with the background color removed to show additional detail as to what the saturation looks like. So it's just a zoom in on that same area.

A-13 shows kind of a mechanistic approach of identifying when wells are closer together or farther apart, what the net impact is, and there is three different cases here. There a case where wells are two miles apart, a mile and a half apart, and one mile apart, and those three cases are all shown on the flow rates on the top section of the graph.

So when they all start injections at the same time, they're all injecting 40,000 barrels a day. And they all continue to inject 40,000 barrels a day until roughly 2000 days.

After that period of time the pressure interference does start to affect the wells, but you can see after 20 years, which is the right edge of the graph, 7000 to 8, the net effect of that interference is still fairly small. There is only a 3000- or 4000-barrel-a-day difference due to the interference, even when the wells are closely spaced. And that's 3000 barrels a day out of 40,000, so the net impact is fairly small. That's Exhibit A-13.

So Exhibit A-14 through A-18 is a time series, and so I will go through them quickly. It basically shows where the water is and what the pressures are in this entire grid over time. And the time series starts with zero years. In A-14 you can see a fairly flat pressure profile and no color on the upper left graph because there is no injection yet.

Once injection starts, we are on Exhibit A-15, after one year of injection all of the wells show a saturation profile change, but very few show the saturation has moved outside of the cell they are in. It only moves one grid cell in one year.

Q. Is this saturation that you are talking about the pressure saturation or the fluid or some combination?

A. That's the fluid saturation.

Q. Okay.

A. Now, the pressures are shown to the lower right, and you can see that's a more uniform trend because you can push pressure farther than you can push fluids. And each barrel of water that gets pushed into the formation will push another barrel of water out of the way, it goes somewhere else, and that barrel that gets pushed out of the way raise the pressure at a distance away from the formation.

So you can see on Exhibit A-15 in the center of the lower, right graph, there is a little pressure pump there, that yellow color, where the pressure in that cluster well is going up.

Now, at the same time, the Cobra well, you can see it, it's kind of in the middle, and it's not showing much of a pressure increase because it doesn't have much injection around it other than itself.

So Exhibit A-16 is after two years. You can see more of the same. The pressure starts to spread.

Exhibit 17 is after ten years, and you can see the pressures are moving outward from here.

Now, just to note, in case you were wondering, Exhibits 14 through 20 -- or through 18 do not have the West Jal in them, but you can see the Cobra and visualize what it would look like if you had another well off to the side that looked similar to that one.

Exhibit A-18 is after 20 years, and you can see in certain cases where the wells are very, very close to together and there is lots in a cluster, they may start to interfere at 20 years. But the area we are talking about for the Cobra is fairly lightly drilled, so there is not much impact there.

And actually Exhibit 19 is a detail of that area, and I've had to rotate the grid so you can kind of see it a little better. But in this case the Cobra and the West Jal are in the graph that's in upper left are the far right-hand side of the graph, and those two, even after 20 years, have not had their influence -- the fluids have not effectively hit each other at that point.

The pressures are shown on the right-hand side, and the Cobra well is shown there with that green color, and the West Jal is shown also with the green color right next to it. You can see that cluster of wells to the right of it, the Maverick, the Javelin, the Patriot, the Moab, those have slightly higher pressure with the concentration with that cluster of wells in that area. So that's A-19.

Exhibit A-20 is a time-based plot that shows the bottomhole pressures for a selected -- a selected set of wells that were all on injection at this time. The goal of this image was to show how the pressure increased on injectors and whether the entire grid pressure changes.

So I have noted there with the callout that says, "Observation well pressure changes are not noticeable," there is three lines there that don't change throughout this entire time period, and those are the -- those are the three observation wells that were placed on the grid to identify what the overall pressure regime looks like in the grid that's away from the injection point.

So Exhibit A-21 shows injection rates for all these wells. And some of them in this particular scenario came in lower than 40,000 barrels a day. There is a cluster of wells down in the lower end that were old injectors that I operated at the rate that they were currently producing.

The new injectors came on at 40,000 barrels a day. You can see they produced up until day 6000, roughly, where they started to hit the maximum injection pressure, and only the Striker and Alpha wells hit that maximum injection pressure, and they happened to be to the far northeast where the zone is the thinnest. So in the thinner zone, it's tougher to inject for long periods of time without the pressure starting to kick back.

And my last exhibit is 22. It shows a little bit of detail on the area around the Cobra well, and these are four wells that the pressure is showing them over 20 years, and you notice they all kind of increase slowly as you would expect them to at 40,000 barrels a day injection.

The one outlier was the Raptor well, and it did not increase in pressure as quickly as the rest. The reason for that was it was kind of to the southeast of all the rest of the wells, so it's basically looking at Texas for the next injector over, so it didn't increase quite as fast, but these wells are all injecting at the maximum injection rates. Again, worst-case scenario.

Q. Thank you for walking us through all of those slides. Based on your slides, and your opinions, and your studies, is it -- what's your conclusion about the thickness of the injection zone?

A. This zone is very thick in terms of history historical standards. 1500-foot thick zone is world class in any case, and so it's a very good injection zone because it's low pressure and thick and high permeability.

Q. And does your study show or did you reach any conclusions about the impact on reservoir pressures overall?

A. At these injection rates, even though they are high, the area is large, the vertical and horizontal permeability is there, and so overall fluid pressures will dissipate through the greater structure. And another case I run is to shut in a while and watch happens to the pressure after that, and the pressure dissipates very quickly once the well is shut in. It basically means the fluids spread out and move away from the injectors as time goes on.

Q. In your testimony you talked about the formation fracture gradient or the frac pressure, and the wellhead pressures are all set below that formation fracture gradient; is that right?

A. That's true. My understanding is the .2 psi per foot surface pressure gradient is set such that the net injection pressure at the bottomhole location is below the fracture pressure. So as long as that maximum injection pressure constraint is honored, it's physically impossible to go above the fracture pressure.

Q. So stating that another way, it's physically impossible to, at least under what we know, to cause fractures in the formation as long as they keep that psi at the point is honored?

A. That's correct. A typical fracture gradient, just a default fracture gradient is .7 psi per foot, and that constraint with the hydrostatic gradient is .65, so it's effectively starting below what a normal frac rating would be. So if you stay within or, you know, below that pressure at the wellhead, you should effectively stable pressure.

Q. And were the exhibits behind Tab 4 prepared by you or under your supervision or compiled with company business records?

A. Yes, they were.

MS. BENNETT: With that, I would like to ask that the exhibits behind Tab 4 be admitted into the record.

MR. LARSON: No objection.

EXAMINER McMILLAN: Exhibit 4 may now be accepted as part of the record. Cross?

(Exhibit NGL 4 admitted.)

CROSS-EXAMINATION

BY MR. LARSON:

Q. Direct your attention to Exhibit A-19. And did I understand you correctly to say that after 20 years there will be some level of interference of waters injected from surrounding wells including the West Jal B 1?

A. The -- the left-hand note that says Cobra there --

Q. Uh-huh.

A. -- shows the Cobra water saturation around that well, and the West Jal is immediately to the left of that, and I actually see no connection between the two. So that would mean for this particular time frame those two have not effectively touched each other.

Q. And I believe you testified that for your modeling you used 40,000 barrels a day for both the Cobra and the West Jal B?

A. I did.

Q. Are you aware that NGL's application asks for a maximum of 50,000 barrels?

A. I am aware of that, and I could rerun everything at 50,000 and the results would be very similar. It would just be 20 percent faster everything would happen, basically, but this is 20 years, and they haven't touched each other yet.

Extrapolating it forward it might be 30 years before the injection profiles touch each other, and so -- like Todd Reynolds mentioned earlier, the actual injection rate that these wells are being fed tends to be lower than maximum injection rates that are in the file, so I wouldn't expect them to run at 50,000 barrels a day continuously for 20 years.

Q. Let's assume that they are, a scenario where Cobra well is being injected at 50,000 barrels a day and the West Jal B at 50,000 barrels a day, are you able to testify that there would be no interference between those wells over a 20-year period?

A. The term "no interference" is a very strict guideline. Any well in this basement interferes with every other well in the basement if it's a continuous formation, so it's all orders of -- it's all measurements. It might be 1 psi at 20 years. It might be 100 psi at 20 years. And the work I did implied it would be on the order of a couple hundred psi at the most at 20 years.

It would not be an interference to the effect of depth of causing a detrimental injection in either well. Those wells will continue to be injected into at roughly the same rates as if they weren't next to each other or near each other based on my evaluation of the gradient.

Q. Within your engineering expertise, has that interference caused any operational difficulties for either or both of the wells?

A. No, not -- not in the -- not in the scope of -- operational difficulties, to me, would mean driving a well above maximum injection pressure, fracking into it, things like that. Those are the kinds of operational difficulties that one would have to work around, and none of those would be relevant here.

Q. Even at 50,000 barrels a day over 20 years?

A. Yeah. Those two wells are kind of off by themselves. Granted they're 1.2 miles apart, but the next well away from them is pretty far, so basically the pressure profile away from those wells will start out as two little circles and will grow, and then when they do interfere 30 years or 40 years, then those profiles will just grow together and spread out away from that direction.

Q. I assume that -- out?

A. The model represents radial flow, typically, and so they will go in all directions away from both wells, and the fluid seeks the lowest pressure available. So the injected fluids will first inject radially around each well, and then once interference does occur, 30 or 40 years, then the fluids will then distribute themselves accordingly away from the other wells. But by then, after 30 to 40 years of injection at 50,000 barrels a day, that's an extreme case, and by then they will have other issues like casing pressures and the facilities will need to be repaired, and there is a lot of things that happen in 30 years of injection.

Q. That's all I have. Thank you, sir.

A. Sure.

EXAMINER LOWE: Good morning.

THE WITNESS: Good morning.

EXAMINER LOWE: I have a question for you on your Exhibit A-3, the NGL, the increasing tubing size will decrease friction loss and conserve horsepower.

THE WITNESS: Yes, sir.

EXAMINER LOWE: I just want to -- I got lost.

What are you trying to explain on this chart here? What's your point?

THE WITNESS: This chart is designed, or the intent of showing this chart is to show the various pressures that the well will see. And the .2 psi there is the green line that's horizontal shows the surface pressure for this particular well.

This isn't the Cobra, but it shows that if the well were 13,275 feet, you would have a 2600 psi wellhead pressure, that's the maximum injection pressure.

And it shows that of that injection pressure, if you have five-and-a-half inch tubing, you will be eating up half of that pressure in friction loss because the red curve increases up to about 1200 psi at roughly the same injection rate.

And so the intent of this graph is to show, first of all, we never approached the fracture gradient, which is, in this particular well, 8629 psi, and the injecting bottomhole pressure is only about 7500 at 50,000 barrels a day, and then it shows the other pressures that are relevant to the well.

EXAMINER LOWE: And that fracture gradient, is that specific to the study you did here or is it a generalization of the area?

THE WITNESS: This one is specific -- it's a general example. In this case it was 13,275 feet, and the Cobra well is actually deeper than that, so all of these pressures will be higher for the Cobra.

EXAMINER LOWE: And then on your graph, on your left-hand side it says, "Surface or bottomhole pressure." So basically I can choose which number can be surface and which can be bottom?

THE WITNESS: Yeah, I think -- yes, sir. The way I would approach that is only one of these is a surface pressure, and that's the approved wellhead pressure, the green line. The rest of these pressures are either a position independent, which would be the friction pressures, or bottomhole pressures which is the blue curves, those are all referencing bottomhole locations.

EXAMINER LOWE: So you might want to kind of distinguish that somewhere --

THE WITNESS: I agree.

EXAMINER LOWE: -- maybe later on. I was trying to get at what you were trying to say here. Also in your little, I guess, diagram that identifies the color of the lines, your 5.5 it says OD friction DP.

THE WITNESS: Oh.

EXAMINER LOWE: What's DP?

THE WITNESS: Delta pressure, change in pressure.

EXAMINER LOWE: And it says for the yellow line, five times 5.5. Is that what you are looking at, or is that 5725.5?

THE WITNESS: That's a tapered string with seven inch down the majority of the wellbore, and then the five and a half goes into the line near the bottom.

EXAMINER LOWE: Okay. So that diagram you indicate there and the graphing, the actual graph indicates ID tubing.

THE WITNESS: Yes.

EXAMINER LOWE: And this chart indicates OD tubing.

THE WITNESS: You are correct, and OD is the correct term.

EXAMINER LOWE: So it should all be OD?

THE WITNESS: It should all be OD.

EXAMINER LOWE: Okay. And then as what the graph said, at 5,000 barrels per day, the pressure will be about 200 surface hole location pressure, or bottomhole location pressure? Is that my choice, or how would I read that?

THE WITNESS: Okay. So you are referring to --

EXAMINER LOWE: The seven, the yellow line.

THE WITNESS: Yellow line.

EXAMINER LOWE: At 5,000 barrels per day.

THE WITNESS: Yes.

EXAMINER LOWE: Would that be approximately 200 psi?

THE WITNESS: Yeah, that's barely off the axis. It's just negligible pressure.

EXAMINER LOWE: Okay. Okay. I just want to kind of clarify what you're trying to say.

THE WITNESS: Sure. The grand scheme of this graph is the two lines, the red line and the orange line indicating the friction pressure that's lost based on smaller tubing sizes.

EXAMINER LOWE: Okay.

THE WITNESS: And I guess if there is another take-home from this, it shows that at 50,000 barrels a day, you are still below maximum injection pressure.

EXAMINER LOWE: Okay. That's all I have for questions. Thank you.

MR. BROOKS: No questions.

EXAMINER McMILLAN: All I'm getting out of this Exhibit 3 is just basically the lower, you have lower pressure with a bigger tubing.

THE WITNESS: Yes.

EXAMINER McMILLAN: I think Leonard asked all the relevant questions. Okay. What is Exhibit A-13 supposed to mean?

THE WITNESS: A-13 is an image that represents the magnitude of the injection pressure loss based on putting wells far apart or close together. And this -- the intent here was to quantify the interference effect because we say the word "interference," but it's difficult to put a dollar value on it or an injection value on it.

In this case it says these wells all interfere with each other. You have three different scenarios there, a one mile apart, a mile and a half apart, and three miles apart, and the difference in between those three cases can be seen in the red and blue lines up there at the top.

It says the worst case scenario you've lost 3000 barrels a day of injection. Best-case scenario, two miles apart and you've lost a thousand barrels of day of injection.

MS. BENNETT: After 20 years?

THE WITNESS: After 20 years.

EXAMINER McMILLAN: I don't have any more questions.

THE WITNESS: Would you like me to describe the graph?

EXAMINER LOWE: I'm okay. Go ahead.

EXAMINER McMILLAN: You can explain it to me. I don't have any questions.

MS. BENNETT: I just have one follow-up question.

REDIRECT EXAMINATION

MS. BENNETT:

Q. A moment ago Mr. Larson asked you about potential interference between the Deep Jal Well and the Cobra well and when that interference would occur if they were both injecting 50,000 barrels per day?

A. Yes.

Q. Does that assume that the Jal Deep well is injecting into the Devonian?

A. Absolutely. If it's not injecting in the Devonian, there is no interference because the zones are isolated.

Q. So at this point, based on the information we have and our understanding today, if there isn't any injection into the Devonian from the Deep Jal, there would be no interference from the Cobra?

A. Yes. That's a great point, and given that I assumed that the Deep Jal is injecting 50,000 barrels a day into the Devonian, that's almost impossible if they were injecting into other zones as well because that's the maximum injection rate, and I would assume that all the others zones --

Q. I think you might have meant you were assuming the Deep Jal was injecting 40?

A. 40, that's fair.

Q. And you've looked at a lot of well data in this area actual injection rates; right?

A. I have.

Q. Have you seen any wells in this area that are injecting up to 50,000 barrels per day?

A. I have not.

Q. And have you been in NGL cases before when Mr. Duncan has testified that it's only a maximum, that NGL doesn't intend to inject at that rate per day?

A. I have.

Q. And just turning back to Exhibit A-13, does this exhibit just show that over time when wells are spaced one mile apart versus two miles apart there is in fact some decrease in injection capacity?

A. There is a decrease in injection capacity, although the amount is very small.

Q. And that amount over 20 years is, for two wells that are theoretic wells that are one mile apart, the decrease in injection over 20 years is 3000 barrels per day out of 40,000?

A. That's correct.

Q. For two miles apart the decrease is 1000?

A. Yes, it looks appropriate.

Q. Over 20 years there is only a 2000-barrel difference in wells two miles apart?

A. Yes, and that assumes they are all trying to inject 40,000 a day.

Q. So this is again a worst-case scenario depending on who --

A. It is.

MS. BENNETT: Thank you.

MR. LARSON: I have no more questions.

EXAMINER McMILLAN: Closing statements, or is this continued?

MS. BENNETT: No closing statements, although I would just like to confirm that it's only continued for the purpose of determining this notice issue; right?

MR. BROOKS: No, it's continued for more general purposes because we have not yet -- it's continued for all purposes. The reason being that we have not yet established why this case was slated to be continued from this date to later for whatever reason, and that needs to be investigated before we determine the final disposition in this case.

MS. BENNETT: Okay. Thank you.

MR. LARSON: I guess in closing I'd say, the Division has had a policy for the recent past that it likes to see 1.5 miles between Devonian wells, and assuming that BC & D is currently injecting in the Devonian, a fact that I will try to confirm, I think the application should be denied on that basis.

MR. BROOKS: Okay. Then the case will be continued to next docket.

MS. BENNETT: If I could just briefly respond to Mr. Larson's point.

MR. BROOKS: You may.

MS. BENNETT: As the Division is well aware, the 1.5 mile rule is -- it's not a rule, it's never been codified into the books, I believe. And I know in an e-mail to me you indicated that the 1.5 mile spacing requirement is only appropriate on a case-by-case basis when technical data is presented showing that it's warranted. And here the testimony that you have had today demonstrates that a 1.5 mile spacing requirement under these circumstances is not warranted because the testimony and evidence presented today demonstrates there will be no induced seismicity impact, and there will be no adverse pressure impact, and there will be no impact on fresh water resources or correlative rights to mineral interest owners. And so there is no reason to apply the 1.5 mile policy, even if it is something that can be applied, in this application here it's certainly not been demonstrated.

MR. BROOKS: Well, it's only a guideline, it's not a policy yet, obviously, because the state rules that policies that are followed as binding policies must be published in the New Mexico register as rules, but I forget exactly what I may have said about it, so --

MS. BENNETT: You will be reminded tomorrow.

MR. BROOKS: I hope I didn't say anything punitive. Okay?

MS. BENNETT: Thank you very much.

MR. LARSON: Just to clarify, this will be put on, I assume, the second docket in June?

MR. BROOKS: I would assume so.

MR. LARSON: You have asked me to provide a cement bond log if there is one and the fact and information about injection to the Devonian. Should I present it at that hearing or do it prior to that hearing?

MR. BROOKS: What activity?

MR. LARSON: There was a request earlier by Mr. McMillan that I provide a cement bond log for the West Jal B well if there is one, and also information about BC & D injecting in the Devonian, and my question is, is that something I present at the next hearing or provide that to Mr. McMillan prior to that?

EXAMINER McMILLAN: I believe the proper way to handle that is provide it to the parties before the hearing, if it's available, we have to figure out a reasonable time, because I'm not sure how much it's going -- the cement bond log, no one has had a chance to evaluate it, so --

MR. BROOKS: I think a reasonable time would be to provide it before.

MR. LARSON: I can do it before then.

EXAMINER McMILLAN: Okay. All right so this case will be continued until -- to June 27. All right. And we'll come back at 1:15.

(Case continued.)

STATE OF NEW MEXICO)
)SS
COUNTY OF SANTA FE)

I, IRENE DELGADO, certify that I reported the proceedings in the above-transcribed pages, that pages numbered 1 through 99 are a true and correct transcript of my stenographic notes and were reduced to typewritten transcript through Computer-Aided Transcription, and that on the date I reported these proceedings I was a New Mexico Certified Court Reporter.

Dated at Santa Fe, New Mexico, this 30th day of May 2019.

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Irene Delgado, NMCCR 253
Expires: 12-31-19