STATE OF NEW MEXICO

OIL CONSERVATION COMMISSION

HEARING DAY 01

Agenda No. 11-23

Moderated by Dylan Fuge

Wednesday, November 8, 2023

9:09 a.m.

Pecos Hall Hearing Room

Wendell Chino Building, 1st Floor

1220 South Saint Francis Drive

Santa Fe, NM 87505

Reported by: James Cogswell

JOB NO.: 6304851

A P P E A R A N C E S

List of Attendees:

Dylan Fuge, Commissioner/Chair - Oil Conservation Commission

Greg Bloom, Commissioner - Oil Conservation Commission

William Ampomah, Commissioner - Oil Conservation Commission

Daniel Rubin, Attorney - Oil Conservation Commission

Darin Savage, Attorney, Abadie & Schill PC - Cimarex Energy Company

Adam Rankin, Attorney - Colgate Production LLC, Northwind Midstream

Jesse K. Tremaine, Attorney - Oil Conservation Division

Dana Hardy, Attorney, Hinkle Shanor LLP - Targa Northern Delaware LLC

Deana Bennett, Attorney, Modrall Sperling - Chevron

Earl DeBrine, Attorney, Modrall Sperling - Chevron

Cody Comiskey, Chevron

Bryce Taylor, Chevron

Jason Parizek, Chevron

Tom Merrifield, Chevron

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P R O C E E D I N G S

MR. FUGE: I'm going to call the meeting, the November 8th and 9th meeting of the New Mexico Oil Conservation Commission to order.

Welcome, everyone. This is the first meeting in a long time back in the Wendell Chino Building. We are in Pecos Hall. Still working on final tech filled out, but excited to be here.

Just wanted to cover a couple of administrative things because we're new and we're getting to the agenda. If you need to get onto the wi-fi, it's "NMEMNRD public." And the password is "security first," all one word. You will need a pop-up screen that says you agree to the terms and conditions and responsible use. But that should get you on the wi-fi.

For parties presenting cases, please log into the Webex meeting. That will enable you to share your material in the room on the large screen. With commissioners here and other -- I just ask that you mute your audio when you log in with those setups.

And then the last item -- and I'll bring this up a little closer to -- because of some family commitments, I have a very hard stop at five. So I will checking in with parties if we are

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presenting testimony at four to just make sure we can get through it within that hour. Otherwise, we'll continue it to the next day. As everyone saw in the notice, we made allowance for two days given that it originally looked like this was going to be a relatively large docket.

And with that, I'm going to send it around to the first item on the agenda, which is approval of the agenda for today.

And we'll see with my fellow commissioners. Do you have any comments or changes to the agenda?

DR. AMPOMAH: Did you read the roll call already?

MR. FUGE: Oh, sorry. Forgot to do the roll call.

Commissioner Ampomah.

DR. AMPOMAH: Present.

MR. FUGE: Commissioner Bloom.

MR. BLOOM: Present.

MR. FUGE: Let us reflect that the entire Commission is present in person.

And then let's go to the agenda. Does anyone have any comments on the agenda or changes?

DR. AMPOMAH: No.

MR. BLOOM: No. Mr. Chair, I move to adopt the agenda.
DR. AMPOMAH: I second.
MR. FUGE: Let the record reflect the agenda was adopted unanimously.
Have my fellow commissioners had a chance to review the October 12, 2023, meeting minutes?
MR. BLOOM: Yes. Mr. Chair, I move to adopt the minutes.
DR. AMPOMAH: I second.
MR. FUGE: Let the record reflect that the minutes from the October 12th meeting were adopted unanimously.
And we will move on to our active docket. We've got some prior cases set for status conference and some new cases for status conference.
And I know from Commission Counsel and Commission Clerk that there were some filings that were made, you know, within the last 24 hours. So we may, when your case is called up, just ask the party to kind of walk through some of those in case we didn't have a chance to get through all of the pieces.
But the first case that's up is Status Conference in Case Number 23727, Application of Targa

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Northern Delaware for Rehearing of Order R-13507-E, and specifically a request that the Oil Conservation Commission reconsider conditions included in Order Number R-13507-E.

And from our last meeting, the parties including the Division were potentially going to come up with a sort of consensus or unopposed set of condition revisions. So I'll turn it over to the parties.

MS. HARDY: Thank you, Mr. Chair.

MR. FUGE: Please introduce yourself for the court reporter.

MS. HARDY: Dana Hardy with Hinkle Shanor on behalf of Targa Northern Delaware LLC.

MR. TREMAINE: Jesse Tremaine with Oil Conservation Division.

MR. FUGE: Ms. Hardy.

MS. HARDY: Thank you.

MR. FUGE: What's the status of the discussion regarding the order conditions?

MS. HARDY: We are still working with the Division on the conditions. I suspect we'll be able to reach an agreement. It's just a matter of going back and forth a little bit more and making sure that we have agreement on all the issues.

So I don't think we will need a status conference. And I don't think we need a contested hearing date. I think we can just reach agreement on an exhibit that we would attach to propose order, provided the Commission says that's acceptable.

MR. FUGE: That's acceptable to me.

Do my fellow Commissioners have any other concerns?

DR. AMPOMAH: I'm not sure.

MR. BLOOM: Yeah. That works.

MR. FUGE: Thank you, Ms. Hardy.

MS. HARDY: Thank you.

MR. FUGE: The next case up, and it's up for final status conference because it's been kicking around the docket for a while, is De Novo Case 21744. And you know, it's -- in the commission records. It was going to be heard along with Case Number 22018 and 22019. Can I have parties in those cases appear?

MR. RANKIN: Morning, Chair. Morning, Commissioners. Adam Rankin, appearing in this case on behalf of Colgate and here to answer any questions.

MR. FUGE: Can you give us an update on sort of the status of these cases and I believe a filing that you made last night in the cases?

MR. RANKIN: Yes. And I don't know if you want to let Mr. Savage also introduce appearance.

MR. FUGE: Oh, Mr. Savage, please go ahead.

MR. SAVAGE: Yes. Good morning, Mr. Chair, Commissioners, Counsel. Darren Savage with Abadie and Schill appearing on behalf of Cimarex Energy Company. And I assume you can see me as well hear me?

MR. FUGE: Yes, I can.

MR. SAVAGE: All right. Thank you.

MR. RANKIN: Mr. Chair, good morning. In this case, this case has been pending for some time. It took me a little while to review fully the convoluted procedural history here. There is a matter before the Commission for de novo review. And that case was brought by Cimarex seeking de novo review of an order approving compulsory pooling for Colgate.

Parties have had a double hearing in that matter addressing whether or not Colgate was within its rights to proceed and pool Cimarex. That order was entered before the Commission. I believe it's 21629C.

Cimarex filed a Motion for Rehearing. Upon the filing and briefing and arguments on that

Motion, the Commission issued a Revised Amended Order 21629D. We, subsequently after some time that that case was continued repeatedly Holland and Hart, that entered appearance on behalf of Colgate I believe in May of this year, substituted for counsel for Colgate.

Parties have been in discussions since we substituted, Mr. Chair. Mewbourne has filed a case with the Division, Case 23688, in which it seeks to revoke Colgate's order approving its compulsory pooling and to pool itself some overlapping acreage there.

So now we have a case pending before the Division pursuant, I believe, to the Commission's order that it should hear all these competing pooling cases together. And that now is pending before the Division. So Colgate has been in discussions with Mewbourne trying to resolve that issue.

And that case is now before the Division. It's set for a status conference on November 16th's docket before the Division. So I'm not sure exactly. I don't have an update on the discussions there for you between Mewbourne and Colgate. My hope is that we can get that resolved.

In the meantime, Mr. Chair, you are

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correct. I did file a Motion to Reconsider the Commission's decision to amend Order 21629C and pointing out that in our view, there were some fundamental errors in the Commission's decision granting the rehearing and modifying Order 21629C.

So with that, we had filed that Motion. And it is our hope that the Commission will reconsider its track in this case. We believe that the Commission has gotten a little bit off track in its decision there. In light of that, I think you may see more what's happening here, which is an application by Mewbourne to revoke an order that's been in place for more than two years. And we think that's a little bit off course.

So with that, Mr. Examiner -- I apologize -- Mr. Chair, I'll let Mr. Savage respond with any questions or concerns he may have.

MR. FUGE: Mr. Savage.

MR. SAVAGE: Mr. Chair, thank you. I'm glad that Colgate talked about perceived being off course. We feel that the last-minute Motion -- this status conference was designed and stated as the final status conference. And we were expecting to have a contested hearing date set. All the Motions, all the competing applications have been approved and in place, and they have moved from the Division to the OCC for hearing.

Colgate had a substitution of Counsel. That was on March 22, 2023. They have had eight months. They have been in this proceeding for eight months. They have never mentioned in any manner a Motion to Reconsider. They have asked for a number of continuances, which Cimarex has accommodated on every occasion, although expressing our interest in having an expedited, expedient hearing. We have accommodated them, and then at the last minute here, the last 24 hours, they have filed a 23-page Motion to Reconsider.

Now, Mr. Chair, these issues that the Motion addresses. I have not had a chance to fully digest everything and analyze everything. But it looks to me like these have been addressed thoroughly by the Commissioners previously in the rehearing setting. And they have made rulings.

And these rulings were pursuant to the statute of limitations of Statute 7225, in which we made an application for rehearing within the 20-day limitation period. And we believe Colgate has not abided by that statutory 20 days. They have waited over eight months to file a final Motion.

We think that the minimum contested

hearing date should be set. We ask that we move forward with these contested hearings based on circumstances. Thank you.

MR. FUGE: Maybe a point of clarification. Mr. Rankin, you referenced a case. Mr. Savage suggested that all of the cases are done at the Division with conditional orders up and, you know, his position probably before the Commission.

You mentioned there was a Mewbourne case that was set to go up before the Commission next week for same acreage, overlapping acreage, related acreage? Can you provide a little more color on what that pending case is?

MR. RANKIN: Sure. The case is Case Number 23638. It is set for a status conference before the Division on November 16th. That case seems to pool some of the acres at issue here. It overlaps partially with the acreage subject to Colgate's order that was on de novo review.

So I think potentially it has complicated resolution of the competing pooling cases that have been pending before the Commission.

MR. FUGE: So is it your position that, setting aside your Motion that was filed -- but if it was to go forward, that the Commission would need

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23688 to go to order before we could hear the de novo hearing if we decided to in this case?

MR. RANKIN: So Mr. Chair, when you read the Motion for Reconsideration that we filed, we do believe that there's a fundamental problem with hearing Cimarex's competing pooling cases before the Commission. The only matter before the Commission was Colgate's Case Number 21744 and the order that was issued by the Division, Order R21575.

But -- the Commission has authority. Parties who are adversely affected have the right to seek de novo review for matters that went before the Division and were heard before the Division examiner and are subject to a Division order. That's the case with the Colgate matter.

The Commission fully heard that case as a de novo matter and issued an order. So our view is that, as to Mewbourne's case, which is now pending before the Division, if the Commission were to take that up for de novo, it would have to have an order at the Division level first.

MR. FUGE: Mr. Savage, do you have a response?

MR. SAVAGE: Yes. Since this is a last-minute motion, we don't feel it's appropriate for

Mr. Rankin to be arguing this without us having the opportunity to review and respond.

But Mr. Chair, it is correct that there is a case pending by Mewbourne. I have talked to counsel from Mewbourne. I don't believe he is here to comment. But as I understand it, that's very close to being settled by the parties.

In fact, they were trying to decide whether or not even the case on November 16 was going to go forward. And if it does go forward on November 16, I believe that if we do set a contested hearing date that that case could be directly moved to be included as a contested hearing on that particular date, whatever the OCC decides to set.

And if it's resolved, which it looks like it will be based on the conversations I've had, then it would be a moot point. And so it wouldn't impact the proceedings. Either way, I don't believe it would impact the proceedings. I believe they could be accommodated within the contested hearing date, or it would be a moot point.

MR. FUGE: Looking to my fellow commissioners if they have questions.

But maybe Commission Counsel, we got the motion last night. I don't recall in our rules what would be a normal opportunity to respond to a party in it. Do they prescribe that?

MR. RUBIN: I don't know offhand if the rules do. But it would be an abundance of caution to allow a written response, I think the point with the Counsel is well taken that we go and set -- the Commission set a hearing, hear the motion. At that onset of that hearing, there's nothing in the rules that prevents that.

MR. FUGE: My fellow commissioners, any questions on this one to the parties?

MR. BLOOM: No, Mr. Chair. But I did not have an opportunity to review the materials that were sent last night or yesterday. In addition, this case has been frustrating. No.

As far as I knew, Mr. Rankin, you're new to this. But I think in the past we've seen moments where Counsel has struggled to even summarize this case which has gone on for so long. So getting up here and not being able to tell us where this is at is frustrating as a commissioner. So I hope that this is dealt with -- manner.

MR. FUGE: So Dr. Ampomah, do you have any?

I mean, hearing the comments from the

Commission and advice from Counsel, Mr. Savage, and arguments from both Mr. Savage and Mr. Rankin, we would -- I guess I'd like to put forward a motion directing Mr. Savage to file a response within two weeks.

MR. RUBIN: Mr. Chair, the examiner for today. Of course he came. It was 72-hours advanced notice of the agenda. So this motion was not on the agenda. All we have on the agenda for this matter is the setting of a final hearing.

MR. FUGE: Fair.

I think to move this case along, because it's been sitting for a while and we've got a Motion, I say we put it for a final hearing. I'm going to Motion to put it on the docket for a final adjudicated hearing at the January 11th meeting.

I would just preserve for the record, Mr. Savage, you have an opportunity to respond to filings and other pieces. And the Commission, consistent with its rules, will provide some guidance how it's going to address those in subsequent agendas.

Is everyone comfortable with a January 11th date between my fellow commissioners for hearing this case?

MR. BLOOM: That will work.

MR. FUGE: And I think I can reiterate what we've heard up here. We would like a resolution. This case has been kicking around for a long, long time.

Thank you.

MR. RUBIN: Mr. Chair, I think this would be better to have a Motion. Is that fair?

MR. FUGE: Can I get a Motion to set -- let's read them out so we've got them. Can I get a Motion to set De Novo Case 21744 and the associated cases 22018 and 22019 for adjudicated final hearing on January 11, 2024.

MR. BLOOM: Mr. Chair, I so move.

DR. AMPOMAH: Mr. Chair, I second.

MR. FUGE: Let the record reflect Motion was approved unanimously.

MR. SAVAGE: Mr. Chair, if I may add an additional comment, I would like to respond to the Motion. Mr. Rankin has had months to review the procedural history in the matters of this case. Could I request three weeks as a time period to respond instead of the two weeks that was mentioned?

MR. FUGE: I'm going to look at Commission Counsel, but I think that the proceeding was filed. On Motions, we typically consider filing well in advance of the agenda at the next scheduled hearing. So if you get your filing in prior to any deadline there, that should be just fine.

MR. SAVAGE: Okay. Thank you.

MR. RUBIN: And we request that you guys -- all arguments on the Motion if it's not on the agenda.

MR. FUGE: Yes.

So that Motion just consistent with practice is likely to be on the agenda for the December 14th meeting. That would be clear when that agenda comes out. Thank you.

I'm going to go to what I think it was mooted by a subsequent filing, but I'm going to look at Case Number 23942, Application of Avant Operating LLC for Hearing De Novo of Case Numbers 23640 through 23645. And my understanding is that Avant made a filing earlier that was a week withdrawing that application.

MS. BENNETT: Yes. Good morning, Mr. Chair and Commissioners. Deana Bennett on behalf of Avant Operating LLC. And I did file a Motion yesterday, I think it was, requesting dismissal of this de novo application.

MR. FUGE: And I'm assuming that

request is uncontested?

MS. HARDY: Yes, Mr. Chair. Dana Hardy for Colgate Production, and the request is uncontested.

MR. FUGE: I think the request is granted then.

MR. BLOOM: I'm sorry, Mr. Chair. Which case number is this? The numbers get a little jumbled.

MR. FUGE: Case Number 23942.

All right. Thank you.

MS. BENNETT: Thank you very much.

MS. HARDY: Thank you.

MR. FUGE: Next up is Case Number 23943, Application of Northwind Midstream Partners LLC for Approval of Redundant Acid Gas Injection Well as Required under Order Number R-20913 as Amended in Lea County, New Mexico.

And can I have the parties appearing for Northwind Midstream come up to counsel table?

Any other party entering an appearance in this matter?

MR. TREMAINE: Jesse Tremaine for the Oil Conservation Division.

MR. RANKIN: Mr. Chair, Commission,

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Adam Rankin appearing on behalf of the applicant in the case of Northwind Midstream.

MR. FUGE: Mr. Rankin, for purposes of the status conference and scheduling, can you just give us a brief overview of the filing and kind of a high-level assessment of sort of anticipated hearing time needed?

MR. RANKIN: Thank you very much, Mr. Chair, Commissioners.

We have been in discussions with the Division on that very matter. We have reviewed the underlying orders that are subject to the proceedings in this case. We filed an application to approve the second AGI Number 2 in this case out of an abundance of caution.

Having reviewed the orders, it's a little bit ambiguous. It's a little unclear, but we believe the Commission may have intended to authorize the Division to approve the AGI Number 2 administratively. So we have prepared the Motion in discussion with the Division to request clarification and for the Commission to issue an order expressly remanding the AGI Number 2 to the Division for administrative approval.

And so essentially, that's where we

stand. We don't think it's necessary at this point, unless the Commission disagrees, for this matter to occupy time before the Commission. And we believe the intent was potentially to remand to the Division for administrative approval. This is in line with other recent AGIs where the second AGIs were authorized by an order in the Pinon and Meredith case where the Commission expressly authorized the Division to approve the second AGI administratively.

So with that, I'll pass it off to Mr. Tremaine, who can discuss more directly the Division's position on it.

MR. TREMAINE: Mr. Chair, I think I agree with what Mr. Rankin said. There's in the order section -- I don't have the order number up in front of me right now. I apologize. But in the order section, there is a reference to Division approval and there's a reference to Commission approval. I have consulted with the technical team, and the subsequent ST108, for the reference, AGI well.

There's two technical changes to that. One is that the surface swell location has moved 125 feet. And the second being that they've modified their plan to drill through a zone that was problematic for the previous as well.

So based on that review, it's the Division's position that the Commission has already essentially approved this well, and that there are technical changes. So it is appropriate for administrative review of this with one additional clarification. The application was appropriately styled because this well was originally conceived as redundant to I believe it was AGI Number 1, which was Devonian/Silurian well.

This is intended, the deeper injection AGI. This one is intended to be the primary injection well. And the DMG well is intended to be redundant or a backup. It will be online first and utilized first, but then at some point, it will be redundant to the deeper injection AGI solely.

The application, like I said, was appropriately styled because this has always been called the redundant well. But the USC group wants to clarify to the Commission that it is no longer the redundant well. And so I think we can clarify that in a proposed order submitted to the Division.

I have reviewed that proposed order, and I think it's satisfactory. I'll make any final recommendations to that, and I think the parties can submit for admissions approval if the Commission's in agreement that this is -- given the nature of the modifications to the second AGI's C108 that it is appropriate for administrative approval.

MR. FUGE: So it sounds to me, in listening to the presentation of the parties, that there may not be the need for a contested hearing in this matter and that you are close to filing a sort of joint order with the Commission, you know, resolving this matter or at least positioning it appropriately from the Division's and the applicant's perspective.

MR. RANKIN: Yes, Mr. Chair. We have prepared a joint motion specifying or outlining the specific language in the order that indicates the intent potentially to authorize the applicant to submit a C108 for the second well to the Division for approval. And that's in Order 20913D, which has been subsequently amended.

But those governing portions have remained in full force and effect. And particularly, you'll see Mr. Scherer [ph] -- and for the record I'll cite to it. But there is a paragraph that Mr. Tremaine referenced. It's ordering paragraph number 1-E in that order. That states that "After OCD's approval of the C108," then it goes on.

So the intent appeared to have been to

authorize the Division to administratively approve that C108. So after further conferring with Mr. Tremaine and the Division, we will likely be filing a joint motion if that meets with the Commission's approval, requesting that the matter be referred to the Division for administrative approval. And we will propose an order addressing that at the same time.

MR. FUGE: Looking at my fellow commissioners if they have any questions.

MR. BLOOM: No questions, Mr. Chair.

DR. AMPOMAH: No questions.

MR. FUGE: Based on the status report from the parties, I don't see the need to set this for hearing. And we will keep it on the docket waiting for that joint motion, but I think that can be resolved just on the papers. So we'll look forward to that from the parties.

MR. TREMAINE: Thank you.

MR. FUGE: And that moves us through our status conferences. And we now have two cases up for adjudicatory hearing, 23686 and 23687.

I'm going to give a short ten-minute recess for the parties to just reconfigure and set up, because this will have witnesses and other components.

So I'm just going to put the line on mute but leave the portal open and allow the parties to go.

And we will reconvene. Let's call it 12 minutes at 9:50.

(Off the record.)

MR. FUGE: Welcome back, everyone. Next items up on the agenda, and these were both set for adjudicatory hearing, Case Number 23686 and 23687. My understanding is the same parties have entered appearances in both cases. And I'm going to ask a question, but I'm just confirming what it appears from the primary statements and the like that the cases will be presented together as opposed to jointly.

Then I'm going to look at Counsel for Chevron first with that question.

MS. BENNETT: Thank you. Deana Bennett on behalf of Chevron USA, and we do intend to present the cases together in a consolidated fashion.

MR. FUGE: Can I have the parties in the case who are entering an appearance just identify themselves?

MR. TREMAINE: Jesse Tremaine for the Oil Conservation Division.

MS. HARDY: Dana Hardy on behalf of Mewbourne Oil Company.

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MR. FUGE: Any other parties either in the room or online entering an appearance?

Hearing or seeing none, Ms. Bennett, you're on.

MS. BENNETT: Thank you very much.

Thank you all for being here. We really appreciate the opportunity. Again, my name is Deana Bennett. And I'm with Modrall Sperling law firm. And I'm here with my colleague Earl DeBrine. And we're here on behalf of Chevron USA, Inc. in these two cases.

I did want to just say how great it is to be back in person and in Pecos Hall. I might stutter on the P a little, but it's great to be back. Great to see people in person. Great to have the opportunity to mingle with our colleagues again, so very much appreciated.

Chevron and ourselves appreciate the effort you made to present this two-well pilot project to the Commission. And we look forward to a robust discussion with the Commission and the other parties.

I do have a few logistical matters that I wanted to talk to before we get started. And some of that may involve the other parties as well in terms of brief opening statements, and I'll get to that in just a minute.

So first I did just want to kind of introduce the Chevron team, if that's okay with the Commissioners.

MR. FUGE: Yes.

MS. BENNETT: We have several people from Chevron here, and I'll just run through that quickly. And some of them are witnesses, and some of them are not. So first, Cody Comiskey, Bryce Taylor, Jason Parizek, Tom Merrifield, Fred Burner [ph], Ochi Achinivu. And we might have some on the phone as well on Zoom, but for now, this is the team that's present.

And this is just a handful of the team, though, that worked on this. I just spoke with Cody this morning, and he mentioned to me that over 24 subject matter experts have worked together in a collaborative way to put together the presentation and the people behind the project.

So the next thing I wanted to just discuss is whether the Commission would like to swear in our witnesses as they testify or as a group before each one testifies.

MR. FUGE: Our practice has been to swear them in as they testify. And we'll ask the court reporter to administer an oath when they're ready to go.

MS. BENNETT: Great. Thank you.

And then I mentioned this briefly to several of the commissioners individually, but just for the group's benefit, our pagination that we had put on the exhibit packet that we prepared is likely different than the pagination that appears to the OCD filing system. And so we intend to use the references to the OCD filing system, which is in the upper righthand corner. And so as we're moving through the exhibits, we'll be referring to that as the exhibit number. And I did pass out hard copies of the exhibit packets.

We did make some revisions to the order of our witnesses yesterday, as well as some slight revisions to the order of exhibits. And so what I will do is refer to the exhibit number in the upper righthand corner and wait for everyone to get to the same page before we start talking about it. But there will just be some little -- I'd say some ebbs and flows in the PowerPoint as we move forward.

I did file the exhibits timely, and our exhibit packet contains six tabs. And we'll walk through each of those tabs with the Commission.

And with that, I think that is all of

the logistical items I had to discuss with Commissioners, but I would like to have the opportunity to present a brief opening statement. And I understand that some of the other parties may like the opportunity to do that as well. So I wondered if the Commission is amenable to that.

MR. FUGE: I have no concern with that approach, so go ahead, Ms. Bennett, and we'll let the other parties go.

MS. BENNETT: Thank you very much.

So I have on the slide on the screen the location, the map of this two-well pilot project that Chevron is proposing and that we'll be discussing today. And the Chevron witnesses will go into more detail about the location of the map. But I did -- to the location of the two wells before I started my opening presentation.

So as I mentioned briefly, this is an SWD pilot project. It's a two-well pilot project. So Chevron is proposing two wells to target the DMG, so shallow injection.

As I alluded to and you as you can see from our team here today, Chevron has undertaken a very extensive review of the surface and subsurface seismic geological factors that are at issue here and that OCD has raised in its materials as well. And Chevron's been working on this project since 2021, so this is a long time in the making to get to the Commission.

Chevron has undertaken this investigation of shallow disposable -- number of reasons, primarily because of the need for additional disposal options to address the high volumes of produced water from the spring and volcanic formations.

And the goal here is to come up with disposal options that do not impair correlative rights and that do prevent waste. So in the testimony you'll hear today, the areas around these two pilot project wells are not favorable for DMG production. The DMG there is either depleted or the geology indicates a low likelihood of unknown DMG reserves. So taking into consideration correlative rates and waste, you'll be hearing a lot of testimony about that today.

We'll also be talking about the low potential for induced seismicity from these particular shallow wells based on the geologic studies that the Chevron witnesses have undertaken. And these wells will also be protective underground sources of drinking water.

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So Chevron has presented this plan to a number of stakeholders and a number of operators. And the operators from whom Chevron has received feedback are supportive of the project. In fact we submitted several letters of support for the project in the exhibits that we submitted.

So there are letters from Coterra, and yesterday we submitted letters from OXY supporting the project. We just received those letters yesterday. And then Mewbourne, I understand from their pre-hearing statement, is supportive of the project. But I'll leave that to them to also discuss.

Chevron's also met with the New Mexico State Land Office and the New Mexico OC.

So I'm going to skip some of these so we can get to the meat of our presentation with the subject matter experts. But I did just want to also highlight that Chevron, you'll be hearing a lot about data gathering and data analysis today, because that's the key element of the pilot project.

Chevron intends and is proposing a request data gathering system or protocol and then intends to share that data with the Division and other operators, not just in the spirit of transparency, but in the spirit of collaboration to make sure that this is a thoughtful approach to DMG disposal, understanding that there are historic concerns about DMG disposal. But Chevron's witnesses will address that.

And just so we're all on the same terminology, DMG is Delaware Mountain Group, just to make sure. So that's that. And we'll have some exhibits that show exactly where the Delaware Mountain Group is within the geologic strata.

So Chevron is also proposing monitoring programs to address any impacts to their rise to correlative rights and waste. And so this is a thoughtful, multidisciplinary approach to the request to have this two-well pilot project approved by the Commission.

And so with that, I look forward to the discussion with the commissioners today and with the Chevron witnesses. And we look forward to any questions that the Division and Mewbourne may have for our witnesses.

Thank you very much.

MR. FUGE: Mr. Tremaine?

MR. TREMAINE: Thank you.

This is Jesse Tremaine on behalf of the Conservation Division. Good morning, Mr. Chair, Commissioners.

The Oil Conservation Division intervened in this case. And it does not oppose the applications. But regarding the nature of the geology and summarizing the Delaware Mountain Group, OCD believes that certain safeguards for these wells are required above and beyond what might be typical for saltwater disposal wells that are injecting into other zones.

We'll get to that in quite a bit of detail once we get into the Exhibit 11 and 12. But very briefly, as we've gotten in the pre-hearing statement, OCD's concerns relate primarily to projection of correlative rights, prevention of waste, and identifying a very key need that Ms. Bennett has already identified, the need for additional data regarding injection into the DMG.

This is an area where I believe the Commission will be informed today the geological information and our understanding of the Delaware Mountain Group is evolving over time. And there's quite a bit of additional information that is necessary and prudent prior to, you know, a rather increased injection development within that zone.

The Oil Conservation Division will

present three witnesses today. First will be Brandon Powell [ph], deputy director for -- Brushy Canyon. Next, we will have Phillip Goetze [ph], the UIC Bureau chief. Then we will have Mr. Million Gebremichael [ph] testify.

We anticipate OCD's presentation taking approximately an hour and a half. Try to stick to that.

Basically, that's a brief outline of OCD's concerns and where we're going with the presentation. So I'll leave it there for now.

MR. FUGE: Ms. Hardy, do you have any opening remarks you'd like to make on behalf of Mewbourne?

MS. HARDY: Yes, thank you, very briefly, Mr. Chair.

As set out in Mewbourne's pre-hearing statement, Mewbourne's reports, Chevron's applications, as long as appropriate conditions are imposed on the injection and monitoring occurs to ensure the protection of correlative rights.

And we did cite in our pre-hearing statement the Commission and Division objection rule, Rule 26, which requires that -- be maintained in such a manner that allows the fluids to be confined to the injection interval. So that's critically important here to Mewbourne.

And in addition regarding OCD's recommendations, Mewbourne fully supports OCD's proposed procedures regarding the administrative approval of DMGSTWD permits that are set out in OCD Exhibit 11. Mewbourne believes these procedures will minimize the risk of waste and protect correlative rights.

Mewbourne also has some other recommendations that I will ask OCD's witnesses about. Really, they are that OCD seek the support of NMOGA, its DMG disposal capacity reexamination workgroup, to create a DMG type log and stratigraphic cross sections to ensure consistent DMG layer picks across the basin and also that OCD consider the requirement to perform a new SRT test, a step-rate test, any time the tubing diameter on the well is upgraded or additional DMG preparations are added below the current disposal interval.

So with the proposed conditions, Mewbourne does support the applications. Thank you.

MR. FUGE: And I just want to check before we go through just to make sure. I believe the State Land Office entered an appearance, but I don't

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see counsel for the State Land Office here or online. But just want to open up that ask in case they have opening remarks. Give a second.

UNIDENTIFIED SPEAKER: Mr. Jared Levy [ph] will not be in attendance today.

MR. FUGE: Ms. Bennett, then. I'll turn it over to you.

MS. BENNETT: Thank you very much.

At this time, I would like to call our first witness, Mr. Cody Comiskey.

MR. FUGE: Can I have the court reporter to administer an oath to Mr. Comiskey?

Think he's ready.

THE REPORTER: Will the witness please raise your right hand.

WHEREUPON,

CODY COMISKEY,

called as a witness and having been first duly sworn to tell the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

MR. FUGE: Thank you.

MS. BENNETT: Mr. Comiskey is lucky, because he's going to be testifying for y'all twice. So he is going to be giving an initial overview of the pilot project and, like, the 30,000-foot view but as

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well as some information on the detailed analysis that has gone into this pilot project. And then he's going to come back later in the day to discuss seismicity. So you will be seeing him again later today.

EXAMINATION

BY MS. BENNETT:

Q So Mr. Comiskey, please state your name for the record.

A Cody Comiskey.

Q And for whom do you work?

A Chevron.

Q And how long have you worked for Chevron?

A Four years.

Q What are your responsibilities at Chevron?

A So I'm a subservice advisor for Chevron's primary business unit mainly focused on water disposal operations planning, seismicity analysis, reservoir modeling, engagement with various stakeholders, regulators, academia. Things of that nature.

Q And what is your -- well, have you previously testified before the Oil Conservation Division or the Commission?

A No, I have not.

Q Have you previously testified before another administrative body?

A Yes, I have.
Q And is that the Texas Railroad Commission?
A Yes, it was.
Q And were your credentials accepted as a matter of record?
A Yes.
Q Can you provide a summary of your educational background?
A I have a Bachelor's of Science degree from Texas Tech University focused on geophysics and tectonics. I graduated cum laude from Texas Tech. I have a Master's of Science degree from Baylor University in geophysics, earthquake seismology, and crust tectonics and kinematics.
Q And do your responsibilities at Chevron include a review of seismic review?
A Yes, they do.
Q And do your responsibilities include SWD development and permitting?
A Yes, they do.
Q Before you worked at Chevron, where did you work?
A Anadarko Petroleum Corporation.
Q And what did you do for Anadarko?
A Had a variety of roles. I worked in our

sales, shareholder development for a period of time. I also worked in our global exploration group. I worked in -- it was focused on West -- development exploration, raw mechanics. I came back to work on our global technology group. Started to focus on more unconventional resource development technology, production management, and then seismicity and water management. That became more of a topic.

Q Thank you. Did you include a brief overview of your qualifications as a resume in this matter?

A I did, yes.

Q And is that resume behind Tab E?

A Yes, it is.

Q Does your area of responsibility at Chevron include the areas of Southeastern New Mexico?

A Yes, it does.

Q Does your area -- excuse me. Are you familiar with the application that Chevron filed in these two cases?

A Yes, I am.

Q Are you familiar with the saltwater disposal wells that are the subject of the two applications?

A Yes, I am.

MS. BENNETT: At this time I'd like to tender Mr. Comiskey as an expert in SWD development and geophysics.

MR. FUGE: So recognized.

MS. BENNETT: Thank you.

BY MS. BENNETT:

Q Let's talk about your initial testimony that we're about to go through this morning, setting aside the seismicity testimony from later on today. What is the purpose of your testimony this morning?

A So the purpose is to present an overview of Chevron's view on water -- produce water management optionality in the Permian Basin. We recognize that there's a growing concern around produced water management. See the rise in seismicity. Induced seismicity has been attributed to -- to produced water management as a growing concern amongst many.

So Chevron's view is looking at this pilot program as a component of water optionality within the state of New Mexico. To be able to continue to develop the resources that are critical to the world, doing it in an environmentally responsible manner, and being forthcoming on information data about -- so that everybody can understand, you know, the issues and finally the opportunities that we have.

Q Great. And earlier today I mentioned that Chevron's been working on this pilot project since

2021. Have you been working on the pilot project since 2021?

A Yes, I have.

Q I have on the screen the location map of the Chevron pilot project wells. Do you see that?

A Yes, I do.

Q And can you just briefly orient the Commission to where the wells are supposed to be located?

A So the Papa Squirrel well is in very Southern Lea County, New Mexico close to the Texas-New Mexico state border. And it's at Veritas 2 State SWD 1 that's located Eddy County, again, proximal to the Texas-New Mexico border.

Q And these wells, are they located within development areas that Chevron has surface control over?

A Yes, they are.

Q And actually, I meant to ask you before we even got to this slide. But if you can briefly give an overview of Chevron's operations and its presence in the Delaware Basin?

A Absolutely. So the -- the map in the upper left is just a broad Permian Basin map I think everybody's probably familiar with. The bottom right shows Chevron's acreage within the Permian Basin. So we have a very large acreage position that Chevron either operates or has -- has daily working interest in. So we're very broad -- broad organization operating in both Southeastern New Mexico, the Texas portion of the Delaware Basin, and also the Midland Basin as well.

Bottom right shows a forecast from our report from 2020, second quarter of 2023, just showing on a half sheet. And it's important to note that we have a significant vested interest in the State of New Mexico and are committed to the State of New Mexico operating.

Q Thank you. So let's talk about why Chevron chose these two specific locations for the pilot wells. And again, this is on page 98 of the materials and using the upper righthand corner pagination. So page 98 of the materials.

If you can just briefly describe why Chevron chose these two specific locations?

A So the two -- it shows two locations in general. We want to accelerate our pace of learning. So we know that geology does vary across the Basin. And so one of the locations in the Papa Squirrel is located in what you would call more of a core portion of the Basin within the Delaware Mountain Group, the DMG.

There's -- there's a tremendous amount of shallow disposal just adjacent to it south along the Texas-New Mexico border. The basin roughly produces about 30 million barrels of water a day. And roughly about 17 million of that are injected. And roughly about 60 to 70 percent of that is injected just along the state line. And so it's very practical then in New Mexico.

As mentioned earlier, we have considerable operations along -- along the -- within the Papa Squirrel AOI. So it gives us a lot of leverage to collect data. We also have existing service facilities there that we can leverage. So it reduces our service impact. We don't have to go out and build new facilities to support this location.

The Severitas too is a little more on the western edge of the Basin. So the -- the geology is just different. And we'll -- we'll show those through exhibits. It's a little shallower.

But again, some of the similar things. There's a considerable amount of injection just to the south of it in the Delaware Mountain Group. It's an area where Chevron has also been drilling shallow

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disposal wells in Texas and operating. And again, it allows us to leverage our footprint from service facilities we have already existing in the area as well as operational synergies that we have.
Q Thank you. When you say existing service facilities, are you talking about existing SWDs?
A Yes, I am.
Q And are those deep SWDs?
A Yes, they are.
Q So what I think you're getting at is that you will be able to use some of those existing service facilities for these SWDs rather than having to start fresh?
A That's correct. Yes.
Q I think we talked about this a little bit, about why there's a need for SWDs generally, which is for disposal options. But why is there a need, in your opinion, for Delaware Mountain Group SWDs?
A So through the last several years, there's been a considerable rise in the number of earthquakes associated with deep disposal. In -- in Southern New Mexico, most of the disposal is deep.
And so looking at optionality, if we have concerns on deep disposal longevity, continuing to face a large amount of produced water, shallow

disposals, one of the options we're looking at to be able to continue to develop the resources but also mitigate the potential concerns around seismicity.

Q One thing I meant to ask you earlier about is that these wells are not proposed for commercial wells; right? These are just for Chevron's use?

A That is correct, yes.

Q I mentioned earlier that Chevron has been assessing the viability of these pilot projects since 2021, and you've been involved in that assessment?

A That's correct, yes.

Q And can you briefly restate or in your own words state for the Commission what that assessment has taken into consideration?

A It's taken to further review both surface and subsurface considerations. Looking at the geology in the area. Broadly speaking, looking at the geology, looking at some of the reservoir parameters, looking at opposite operations, looking at own operations in areas again where you can, you know, actively collect more data that we have control over instead of having to work in a field with maybe 20 or 30 operators within an area that limits our ability to kind of have control.

Again, leveraging our service facilities as much as we can to reduce any more service impact and -- and areas where we have future operations, so we can leverage the wells for use as well. So taking a multitude of considerations into account was -- was kind of a driving factor for these two locations. So it's a -- it's a hybrid of multiple factors that went into selection.

Q And as part of your proposals, have you met with other operators in this area?

A Yes, we have.

Q And what has been the response of the other operators?

A As noted, we received positive feedback from a few operators who have issued support for this pilot program. Late last year, there was a DMG working group that I believe was mentioned earlier that was stood up and had numerous companies to operate the state of New Mexico.

And we presented our plan for the pilot program back in I believe March of -- of this year on, you know, leveraging, going through the work that we've gone over to look at these locations.

And believe the feedback was positive in our ability to not only accelerate our learning as an industry, provide data publicly, collect a lot of information to accelerate our learning for some of the issues. But the -- but the feedback was positive from the industry group that has been working on this.

Q Is part of the reason that you -- or I understand from speaking with Chevron that there was an earlier working group that had expressed that the OCD and OCC should take greater care when considering disposal in the Delaware Mountain Group. Are you familiar with that working group?

A I am familiar with it, yes.

Q And what is your understanding of that working group's goal or recommendations?

A My understanding is that group was -- was looking at, you know, the -- the potential impacts from Avalon and -- and Brushy Canyon production potentially associated with -- with shallow disposal impacts.

And -- and I believe the -- the view of the group was to, again, look at more care for permitting future disposal wells within -- within an area that was established, noted as DMG restricted area or DMGRA that -- that was established. I think most people are aware of.

But I think the view of the group was not necessarily to ban shallow disposal but to look at

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additional data and more care provided on permitting process and execution of such wells.

Q And has that been kind of your driving force is to exercise that care and gather the additional data to demonstrate that disposal within the DMGRA is appropriate under certain circumstances?

A Yes. Chevron -- Chevron is committed to -- to safely operating and acquiring a multitude of data, disseminating it to -- to everybody, to -- to the OCD, to industry, for us to learn about the potential risk, be able to monitor, educate ourselves on more dynamic nature to support future operations.

Q Let's see. I think we've talked a lot about the Permian produced water reduction, so I'm going to skip some of those questions. But I did want to ask you about Chevron's use of recycled water and why recycling the produced water isn't the solution.

A So as I mentioned, the Basin roughly produces about 30 million barrels a day roughly of produced water. You know, Chevron, within its operations, recycles as much produced water as it can through further operations.

However, there's just more produced water than we can recycle. And so the delta is -- is mainly taken to disposal wells for -- for disposals. And in

New Mexico today, there's roughly about a 3 million barrel a day imbalance from produced water.

So based on the oil production in the injected water in Southeast New Mexico, there's roughly about a 3-million-barrel delta, and most of that water is moving across the state line into Texas to be disposed.

Q One of the things you and I have talked about in the past is the potential implications of the water being transmitted or being transported into Texas and how that can potentially impact New Mexico oil and gas operations.

A Yes.

Q Could you provide a little more detail on that? Or did you just do that?

A I believe I just did.

Q And then so earlier a moment ago, Counsel for Mewbourne mentioned the OCD Exhibit 11. And have you reviewed OCD's Exhibit 11, which is --

A Yes, I have.

Q And do you feel comfortable that Chevron's applications are consistent with the conditions of approval in OCD's Exhibit 11?

A Yes, I am.

Q And has Chevron, in your opinion, undertaken

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the analysis that would support a careful review of whether these two type wells are appropriate for disposal in the DMG?

A Yes, I do.

Q In your opinion is the Papa Squirrel SWD Well Number 1 appropriate for disposal in the DMG?

A Yes, I believe so.

Q And in your opinion, is the Severitas 2 SWD Number 1 appropriate for disposal in the DMG?

A Yes, I believe so.

Q Based on the work that you and your team have done and that we'll hear about more later today, do you think that the pilot project will negatively impact correlative rates?

A No, I do not.

Q And based on your analysis and Chevron's analysis, do you think that the project will result in waste?

A I believe not.

Q Do you think that the risk of waste is -- I know that other witnesses will talk about this a little bit more. But is the risk of waste and the protection of correlative rights even more evident here because of the lack of DMG offset producers in these two areas?

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A Can you state --
Q Sure. So if part of the concern is the potential impact on DMG producers, has Chevron undertaken a review of the impact on DMG producers in the area?
A Yes, we have.
Q And is Chevron's conclusion that these two pilot projects or these two wells would not negatively impact those DMG producers within the area of the --
A Yes.
Q Have Chevron considered whether its shallow disposal will impact drilling and completion at a deeper strata?
A Yes, we have.
Q And will there be a witness who will testify about that later?
A Yes, there will be.
Q So before we move onto our next witness, I'll open you up for questions from the other lawyers and the Commission. Do you have any final takeaways that you want to say about the pilot project since you've been working on it for so long, and it's sort of your baby?
A Yes, I do. This is -- this is part of a broader position from Chevron looking more optionality

in produced water. The amount of water again that's produced on a daily basis in the Permian is unlike any other unconventional plate ever in the history of oil and gas. And it poses unique challenges that faces everybody in this room.

So one of the components of Chevron's approach on -- on environmentally safe produced water management is the expansion of optionality within not on the state of New Mexico but across the Permian. And one component of that is re-looking at shelves within Southeast New Mexico.

We feel that these locations provided an opportunity for not only Chevron, the industry, the OCD and everybody involved to learn about potential consequences and concerns, understand those, understand the opportunities that could be there that will allow for development of the resource within the state of New Mexico and across the Permian to support, you know, the -- the -- of that.

MS. BENNETT: Thank you. Those are all the questions I have for you at this time. And I open the floor for other questions from the Commission or other counsel.

MR. FUGE: Mr. Tremaine, do you have any cross?

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MR. TREMAINE: I do have a couple questions. Thank you.

EXAMINATION

BY MR. TREMAINE:

Q So I believe during your testimony, you stated that this pilot project was considered kind of a broader view of development of injection activity in the DMG. Is that a fair assessment?

A Yes.

Q If this pilot project is successful, what's the scope of Chevron's anticipated injection development within the DMG in this area?

A I think with that, our scope is -- is going to be tactical. It's going to be "What does the data tell us?" From -- from future projects, when we look at these, really, it's a case-by-case basis. We look at these in review of all the technical information and also too our -- our pace of development, locations, many different factors.

But we look at this as a key component to understanding what our -- the future of produced water management may look like. But we are utterly dependent on "What does the data tell us operationally from the subsurface, from the facilities, which we'll speak to later, how they can maybe potentially be expanded upon down the road given the information is disseminated and reviewed in a proper manner.

Q Thank you. I believe that you mentioned that Chevron performed a review of potential impacts on current production within this area; right?

A Yes.

Q Did you look at potential future production, or did Chevron focus on current, existing production within the area?

A We looked at both. We looked at existing legacy production what's in the area and also a geological review that could lead to future production areas as well.

Q So is it my understanding then that that Chevron review of production in the area -- well, how would you describe a future potential production in the area potentially impacted by this development?

A So we looked at the different benches that could -- that potentially are productive. We looked at a geological review that'll be -- that'll be talked on more in future testimony on, you know, geological, you know, ingredients, which could lead to future development, obviously historical development, things like that. But that will be discussed in the -- in future testimony.

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Q And just one other topic really quickly. It sounds like you've had an opportunity to review OCD Exhibits 11 and 12; correct? Administrative approval, processing conditions, and the separator tests. You may get to this later, but does Chevron have any specific concerns for items to address in those exhibits?
A Yes, we do. And I -- I believe we will address those questions later in some other testimony, but we do have a few questions we would like to ask.
MR. TREMAINE: I'll reserve the questions then. Thank you.
MR. FUGE: Ms. Hardy, do you have any questions for the witness?
MS. HARDY: I don't at this time. I expect to have some questions for Mr. Comiskey on the seismicity testimony, but I have no questions right now.
MR. FUGE: Looking at my Commissioners, Dr. Ampomah, do you have any questions for the witness.
DR. AMPOMAH: Yeah, a quick one.
So can you clarify the use of the word "pilot"?
MR. COMISKEY: Yes.

DR. AMPOMAH: And the application.

MR. COMISKEY: So I think when we -- that's a great question. Thank you, Commissioner, on that. Think the -- our view on a pilot project is that, you know, we're acquiring a lot of data that's not normally acquired in -- in DMG wells. I would argue this is probably one of the most science DMG disposal permit in the Basin.

So from that perspective, we look at these as -- as an opportunity to learn. We look at these as -- as just like any other disposal well, as an opportunity to dispose as well. But from the pilot perspective and the way we voice this to not only to the OCD or the State Land Office but to industry is we want feedback. We want to be able to -- to incorporate that from a broad perspective and include that in our operations.

And so that's kind of a -- a typical -- that's atypical from a traditional development plan, which is very, you know, thought out and executed. This is something that -- that I think we're going to have a little more flexibility on. So that that's kind of where the pilot is coming from.

DR. AMPOMAH: So your testimony talked about how Chevron talked to multiple counties in the area and they received approval. So with their concerns, some of the written social reason how you were able to address those?

MR. COMISKEY: Yes, there -- there were concerns. We did have a few protests on those wells, which we've -- they've been dropped and removed through the ongoing discussions. And I think the biggest thing from our perspective is we want to be open. We -- we're collecting a lot of data.

We recognize there's concerns. Obviously, there's been historical testimony. It's been presented as exhibits and something that Chevron was -- was involved in. We're not shying away from those, so we recognize there's concerns.

But we also recognize this is an industry issue. Produced water management is not just a Chevron issue. This is an industry issue. So we need to work together. And so we look at this as an opportunity for us to, you know -- we're going to put capital in these projects.

We're going to take data, collect data, provide it, and we hope through this and through the ongoing through the New Mexico work group that was mentioned earlier, that we can collectively work together to understand any issues, understand opportunities, things like that. So that's -- that's something we'll find out.

DR. AMPOMAH: My last question will be I just want to know if these two proposed wells are the area where the -- more or less after the data as a protected area.

MR. COMISKEY: These wells are within the area, yes.

DR. AMPOMAH: Thank you, Mr. Chair.

MR. FUGE: Mr. Bloom?

MR. BLOOM: No questions at this time, Mr. Chair.

MR. FUGE: I had a couple questions I wrote down, but I think you already covered them when you talked about seismicity, so I'll reserve to there.

I did have two, though, other questions. You indicated that one of the reasons why you chose this location is for Chevron's interest in the area. What proportion of the area around, meaning surface and subsurface, does Chevron currently control?

MR. COMISKEY: Which area?

MR. FUGE: Around the Severitas and Papa Squirrel wells.

MR. COMISKEY: I don't know off the top

of my head what percentage. I know that we operate production wells in the Avalon and the Wolfcamp below the Papa Squirrel location. And we operate production wells and -- and the Bone Spring Wolfcamp below the Severitas location. So both those sections, Chevron operates and has -- has license to operate. And those are lease agreements to operating those.

So within the sections, a hundred percent. But I don't know within the -- within the area the exact percentage. I -- I think we have a few slides open a little further that will show a little bit more detail.

MR. FUGE: Did I hear correctly that Chevron is the owner of some DMG offset wells in the area around Papa Squirrel and Severitas or?

MR. COMISKEY: We are and -- and we are in the case of the Severitas.

MR. FUGE: And then I think building off Commissioner Ampomah's questions about the pilot nature, maybe I'll provide a little context for my question. When thinking about pilots and other pieces, are there any dates proposed in Chevron's application to either come back into the Commission or others to revisit what you're learning about? Or is this a standard kind of 30-year term SWD permit with

the feedback?
MR. COMISKEY: No, it is not a standard 30-year term permit. We have -- and I will speak to in -- in my later testimony on -- on response framework that was developed with support of the working group on -- on signpost on data dissemination. We -- we hope to have ongoing engagement with the OCD and industry on this as we collect and learn information. So we hope this will be very open-ended and -- and very collaborative.
MR. FUGE: I don't think there are any other further questions from the Commission, so you may be excused. Thank you.
MS. BENNETT: Thank you.
MR. FUGE: All right. Call your next witness.
MS. BENNETT: Thank you. I'd like to call Mr. Tom Merrifield.
MR. FUGE: Can I ask the court reporter to swear in Mr. Merrifield?
THE REPORTER: Will the witness please raise their right hand?
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WHEREUPON,

TOM MERRIFIELD,

called as a witness and having been first duly sworn to tell the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

MR. FUGE: Thank you.

Proceed.

MS. BENNETT: Thank you.

EXAMINATION

BY MS. BENNETT:

Q Mr. Merrifield, would you please state your full name for the record?

A Yes. My name is Tom Merrifield.

Q And where do you work?

A I work for Chevron.

Q And how long have you worked for Chevron?

A Eleven years.

Q What are your responsibilities at Chevron?

A My primary -- primary responsibilities for Chevron are to assist in permitting saltwater disposal wells, to plan saltwater disposal wells, and to execute saltwater disposal wells, and primarily in the Delaware Basin, which includes Southeast New Mexico.

Q And so your responsibilities include designing SWD, saltwater disposal wells?

A That is correct.
Q And operation of saltwater disposal wells?
A That is correct.
Q And have you previously testified before the Oil Conservation Commission or the Oil Conservation Division?
A No, I have not.
Q Did you provide a resume with your materials?
A Yes, I did.
Q And is that behind Tab E?
A Yes.
Q If you could, could you briefly summarize your educational background for the commissioners?
A Yeah. I have a Bachelor of Science degree from Texas A&M in geology, and I have a Master of Science degree from Southern Illinois University at Carbondale.
Q And you mentioned that you worked at Chevron for 11 years. Where did you work before Chevron?
A Various places. I worked in the water resource, you know, sector for approximately 16 years. I've also worked in the Permian Basin previously for ARCO as well as Exxon. And I've worked -- I also did work somewhat with the Hershey building program for

about six years.

Q One of the things you and I talked about a bit when we were talking about your professional experience was the number of UIC wells that you've been involved with in terms of design, permitting, operation. If you had to guess, what is the number of UIC wells that you've been involved with?

A Just for clarification, I worked for oil and gas at UIC wells. I've worked both water flood as well -- as well disposal wells. And somewhere in the order of a hundred.

Q And again, that's both water flood DOR wells and SWDs?

A That's correct.

Q If you were to limit that to just saltwater disposal wells, about how many saltwater disposal well projects would you say you worked on?

A About 20.

Q So your background, you've done a lot of work with saltwater disposal wells and other injection wells? Is that a fair statement?

A Yes.

Q Does your area of responsibility at Chevron include the areas of Southeastern New Mexico?

A Yes.

Q Are you familiar with the application that Chevron filed in these matters?
A Yes.
Q Have you been working with Chevron on this particular project since 2022?
A Yes.
Q And are you familiar with the wells, then, that are the subject of the applications?
A Absolutely.
MS. BENNETT: At this time I would like to tender Mr. Merrifield as an expert in UIC terminating and operation matters and petroleum geology.
MR. FUGE: The witness is so recognized.
MS. BENNETT: Thank you.
BY MS. BENNETT:
Q So I'm going to start sharing my screen again, and we'll start with the applications that Chevron submitted to matters. So Mr. Merrifield, before I turn to the applications, though, what is the purpose of your testimony today?
A Really to just kind of walk through the C108 application first. Also to touch on the geology of the injection intervals and how favorable they are --

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and also to address some of the -- their indicators of the likelihood of DMG reserves in -- in both of these areas.

Q Great. So let's start with the discussion of the C108s. Are the C108s included with the applications that I filed on Chevron's behalf?

A Yes.

Q And turning to Tab A, which is at page 3 of 267, does that look to you like the application that I filed along with the C108 that you provided to me to include with the application?

A Yes, it does.

Q And Tab A is the application in Case 23686 for Papa Squirrel; is that right?

A Yes.

Q And Tab B is the application in Case 23687, which is for the Severitas well?

A Yes, it is.

Q Did you compile the materials? Well, let's focus on Papa Squirrel for a moment.

A Sure.

Q Did you compile the materials that were submitted as the Papa Squirrel C108?

A Yes.

Q And did you submit that material to me?

A Yes, I did.

Q And in your opinion, does the C108 for the Papa Squirrel well include all of the information and documentation required by the C108 and by the Commission?

A That was my understanding, yes.

Q Did you review OCD's, the Oil Conservation Division's pre-hearing statement in this matter?

A Yes.

Q And did you see in the OCD's pre-hearing statement where the Division noted that the C108s comply with the current construction? Or the well bore side, I should say, comply with current standards for UIC Class 2 well?

A Yes, I did see that.

Q And did you see where both the wells were designed for the area of review to be adequate?

A Yes, I did see that.

Q So with that initial stamp of approval -- although I'm not trying to go too far with what OCD said in its pre-hearing statement. But I think that does narrow our inquiry a bit and discussion on C108. So with your permission, I'd like to go through the C108s rather quickly.

A Okay.

Q So did Chevron submit a map that identifies all wells within 2 miles of the Papa Squirrel well?
A Yes.
Q And is that Attachment 1 to the C108?
A Yes.
Q Did Chevron attach data within the AOR, so the area of review for the wells, if there are any, which penetrate the proposed injection zone?
A Yes.
Q And was that Attachment 2?
A Yes.
Q And in your materials, is there a plugged well within the AOR for Papa Squirrel?
A Yes.
Q And did you submit the plugging information from the well files?
A Yes.
Q Did you include information regarding the requirements for showing how much volume or the daily rate of injection and the proposed pressure?
A Yes. The operational part, yes.
Q And I just want to take a quick look at that. That's Attachment 3; right?
A Yes.
Q And so on Attachment 3 for Papa Squirrel,

what maximum rate of injection or barrels of water per day is Chevron requesting in the application?
A For Papa Squirrel, 20,000 barrels a day.
Q And what is the average daily rate?
A 15,000 barrels per day.
Q And what is the max permit pressure that Chevron is seeking for Papa Squirrel?
A 125 psi.
Q And how about the average pressure?
A 750 psi.
Q Thank you. Did you submit geologic data with your C108s?
A Yes, I did.
Q And is that Attachment 4?
A Yes, it was.
Q Did you provide information on the proposed stipulation program?
A Yes, I did.
Q And is that Attachment 5?
A Yes, it was.
Q Did you provide logging and test data on the well?
A Yes, I did. But this well has not been through -- what I -- what I showed in that -- just in that attachment was what we were planning to -- what

kind of data we were going to gather after an oil spill.

Q So because it is not an existing well, no wells have been run. But this Attachment 6 does show some of the logging that Chevron is proposing to do?

A Yes, it does.

Q So I'm just going to skip Attachment 7. There were no wells within the area of review for Papa Squirrel; is that right?

A Yes.

Q Attachment 8 is what I call in shorthand the affirmative statement. And it's an affirmative statement signed by you; is that right? Is that your signature?

A Yes.

Q And did you submit the statement saying that you, on behalf of Chevron, had examined the available geologic and engineering data, and you found no evidence of open faults or other hydrologic connections to underground sources of drinking water?

A Yes, I did.

Q And that's based on your review of the materials?

A That's correct.

Q And is that still your conclusion today that there is no connectivity? Or you have not found any connectivity?

A Yes.

Q Let's turn to the Severitas C108. And I'm not going to walk through that in any level of detail except to ask you about the rates and pressure. But did you provide all of the same information for the Severitas C108?

A Yes, I did.

Q And if we turn to page 66 of 267, which I'm showing on the screen, is that the operational data information that's required by the C108?

A Yes, it is.

Q And what is the maximum rate that Chevron is requesting for the Severitas 2 state well?

A 15,000 barrels per day.

Q And what is the average daily rate?

A 12,500 barrels per day.

Q And Chevron is requesting lower psi, is that right, for this well?

A Yes, it is.

Q And what is the max pressure that Chevron's requesting?

A 468 psi.

Q And the average pressure?

A 400 psi.
Q Did you prepare an affirmative statement for the Severitas well as well regarding the evidence of open faults or other hydrologic connections to your SDWs?
A Yes, I did.
Q And is that Attachment 8?
A Yes, it is.
Q If you could just read this last paragraph here, starting with "Both the Papa Squirrel"?
A Okay. "Both the Papa Squirrel 781 and the Severitas 2 State SWD 1 are -- are locations which we find" -- excuse me.
Q Yeah, I know. It's so small.
A "Find no indication of open faults at the surface or in the subsurface. No indication of hydrologic connection between the proposed injection zone, Bell Canyon and Cherry Canyon, and the underground source of drinking water. Both locations have low potential for offset and reduce substance."
Q Thank you. And is that still your conclusion today for both wells?
A Yes, it is.
Q Are you familiar with the stimulation program that Chevron is proposing for these two wells?

Or is that a question better for someone later in the day?

A I'm familiar with it enough to answer a brief statement on it. But yes, there is someone else later today that can address that more -- more.

Q Well, let's start with you. And if we need to defer, we can. So have you looked at the OCD's Exhibit 11?

A Yes.

Q And just do you recall that in Exhibit 11, OCD was proposing a limitation on how shallow DMG SWDs are stimulated?

A Yes.

Q And in your opinion is your proposed stimulation program consistent with what OCD is looking for in terms of a stimulation program?

A Yes. And it's just a -- it's just an acid job. That's -- that's the stimulation.

Q Do you recall what OCD was suggesting would not be an appropriate stimulation method?

A It's my recollection I think what they were concerned about mostly is -- is this one would hydraulic fraction with -- and with profit without hydraulic stimulated fracture. This -- this proposal is not going to utilize either one of those methods of stimulation.

Q So having reviewed OCD's conditions of approval, it's your opinion that your stimulation program is consistent with OCD's request?

A It's my understanding, yes.

Q Thank you. One thing that you and I have spoken about is a potential need in the future to microsite. To make some micro siting changes, I'll call them, to the location of the Severitas well?

A Yes.

Q And why would Chevron perhaps need to move the service location of the Severitas well a few feet here or there?

A Currently, the location that's in the application is in our lay down yard in the area. It would -- there's still a chance that that may work. We have to make sure that the -- the footprint can fit in there without going across roads and things of that nature.

There's another location that's about 200 feet away that we -- we think we can move to. And we will make that decision after hearing.

Q But before coming here today, you and I talked about whether that change in location would change any of the parties who were entitled to notice

of the hearing. Did we talk about that?
A   Yes, we did.
Q   And what was your conclusion?
A   We -- we evaluated that a few weeks back. And there is not going to be any change in the entities that need to be notified if we move it to that location.
Q   Now, the applications and the C108s discuss injecting into the Brushy Canyon. But just to be perfectly clear, Chevron does not intent to inject into the Brushy Canyon; is that right?
A   We are not planning to operationally inject produced water into the Brushy Canyon formation. In fact, after we've logged the route in the Brushy around defects, we plan to plug off that Brushy -- Brushy Canyon and only inject into the Cherry Canyon and Bell Canyon. And we are not drilling into the hollow part of the Brushy either.
Q   So let's kind of take that statement and unlock it just a little bit.
A   Sure.
Q   So what is a DFIT?
A   DFIT is a diagnostic fracture injection test. So we actually do inject fluid into that formation. It's usually fresh water or some very

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compatible formation fluid. But it's usually fresh water. And so they're very short-term injection tests, very minor, but they are injection tested going to the formation.

Q   And is this DFIT test part of Chevron's data collection protocol?

A   For these wells, it is part of the -- our protocol.

Q   And my understanding though is that the sole reason that you had included the Brushy Canyon in your applications at all is to authorize this DFIT test?

A   It -- it's to authorize the DFIT test, but also to conduct open hole logging within this portion of Brushy Canyon. And the open hole logs -- are going to be resistivity, gamma-ray, sonic, and neutron density. We'll also be running image logs as well.

Q   So maybe I was too narrow saying it was just for DFIT. But really it is just for testing purposes, and then you'll be cementing it off?

A   That's correct.

Q   And so it's a very limited purpose?

A   That's correct.

Q   And the targeted -- just to clarify, it is not a targeted injection interval?

A   We are not targeting for reduced water

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injection.

Q Thank you. And so with that, I did want to turn into the well bore designs. Now, these were in your C108s, but you also inserted them side by side in a slide for our convenience. And that is on Slide Number 101. So if we could move to Slide 101, I wanted to talk through the casing designs a little bit, the well bore designs.

A Okay.

Q And as we talked about earlier, the Division has already said that the well bore designs are consistent with the construction standards these days for UIC Class 2 wells?

A That is my understanding.

Q But what I liked about your well bore designs is that they give us a little bit more information about where the closest aquifers are and some of the formations that provide -- above and below the targets.

So I was wondering if you could walk us through the Severitas State SWD Number 1 casing design or well bore design first, and then we can move to Papa Squirrel. And I might have some questions for you as you're walking through it.

A Okay. Both wells are a three-strand casing design. And the Severitas well, we have a very -- we don't have much of an aquifer present in that location. But we do have a very thin, less than 100 foot -- aquifer in that location. And that extends down to about 400 feet.

The second string as you enter is the intermediate. It will be set in Lamar formation. And then we have a third string, which will be set in the -- about 500 feet above the basin Brushy Canyon formation.

Q And so in your opinion, is the three-string casing design protective of underground sources of drinking water?

A Yes, because if -- essentially, that design will have a two-string -- two layers of containment protecting the -- aquifer.

Q And I see on these two slides that Chevron's proposing to use 5 1/2-inch tubing; is that right?

A That is correct.

Q And did you notice in the OCD's Exhibit 11 that OCD was also recommending 5 1/2-inch tubing?

A I think they're saying that they would not approve anything larger than 5 1/2 inches around. Yes, it is consistent.

Q Great. And then the other thing I wanted to

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talk about on her is the upper containment zone and the lower containment. So let's start with upper containment, which is noted right here. What can you tell us about the upper containment?
A The Lamar limestone is considered the upper containment zone for the projection for the Severitas well. The lower containment zone of the well is the limestone, which is shown at the base.
Q And Chevron has other witnesses today that will talk about some pressure tests and things that were done on those two containment zones later today; is that right?
A That is correct.
Q But one thing I did want to talk about with you because I find it to be quite interesting was you and I had talked about the presence of anhydrites and how those can act as a seal or sort of reinforce the seal for containment zones. Are there anhydrites present here?
A Yes, there are. Anhydrites are -- are a part of basically the whole component of what's shown here on the diagram as the Castile formation.
Q And the Castile formation is this upper area above the line?
A And correct. Well, it's right above the

line.

Q And when you and I spoke, what I found to be interesting was that Castile and Lamar together interact in a way because of the anhydrites to create an even greater seal?

A That is correct. The essential -- what's interesting about the anhydrites in Castile is when we assess the mechanics of those units that the high density Castile lies on top adds to the fracture screens of the Lamar. And Bryce Taylor will talk a little bit more about that later today.

Q Thank you. I just find that to be quite interesting that in aggregate, that together they're stronger than they would be individually?

A That's correct.

Q Let's see. What is the vertical distance between injection and the rustler in the Papa Squirrel? Is that noted on here or have you done the --

A It -- it's not shown on here. I think the question is what's the vertical difference between the top of injection and the shallow aquifer. And that distance is about 2200 feet in the Severitas well.

Q And have you calculated the same thing for Papa Squirrel?

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A Yes. That distance is about 3700 feet. And -- and in that case, it -- we do have rustler present. And so it's really from the top of injection at the top of the bell right below the Lamar to the base of the rustler in the Papa Squirrel well.
Q But there are multiple thousands of feet of vertical separation?
A Correct.
Q And earlier we were talking about the DFIT test and cementing back. And do these show the cementing back to prevent injection of produced water into the Brushy?
A Yes, they do. It -- to touch on the Papa Squirrel, there's an additional language that's left over from a diagram that went back and forth between myself and -- and wells, but really, the cement is -- the cement plug in the -- within the Brushy Canyon is what we're planning for both wells.
Q Now I wanted to turn to a study that you prepared to show the porosity of each of the two wells and their favorability or the geology as an injection interval. And here I'm going slightly out of order. So at this time, I'd like to turn to Slide 103 of the material. And again, that is the number of the top righthand side.

A Okay.
Q The substance starts on page 104. So the slide I'm looking at now says, "Bell Canyon High Porosity: Papa Squirrel." Are you there with me?
A Yes. Yes.
Q What is the purpose of the analysis that you undertook in this slide?
A The purpose of this analysis was really a prelude to identifying what -- where the optimal locations are in both of these development areas. The Salado Draw. And that's what he was talking about, the Salado Draw here in the Papa Squirrel well as -- as proposed.
Q And let's maybe take a moment and walk through these. Before we do that, what is your conclusion from the study that you undertook in terms of whether the injection interval is favorable in the Bell Canyon for the Papa Squirrel?
A Our -- our determination is the Bell Canyon is -- is very favorable for injection in this area, and it's primarily due to the stacked thickness of high porosity sands within the Bell Canyon in this area.
Q And did you reach this same conclusion in the next slide, which we'll turn to in a moment, for

the upper area?

A Yes.

Q And did you prepare the same analysis or a similar analysis for the Severitas well?

A Yes. I think -- and you'll find that the -- the slides are slightly -- the diagrams are slightly different, but they're -- they're made by other geologists that were involved in this process, and they just took slightly different approaches, but they came to the same conclusion regarding the net thickness of porosity within the two areas.

Q And is that conclusion that that thickness is favorable for injection?

A Yes, it is.

Q Let's start then on this slide, which is number 104 of 267. And let's start with an orientation of the slide for the commissioners and the other parties. What is this right here that I'm highlighting?

A This is an inset that shows where that portion of the map is located relative to the Delaware Basin that's shown where the tan lines are kind of projected into the map -- the second map.

Q And if you had to guess about -- I mean, if you had to identify on this map where the Papa

Squirrel well is, is my hand more or less?
A That is approximately where it's located, yes.
Q And so what does A to A prime mean on this slide?
A This is a line of the projection, the cross-section that's shown on the left.
Q And does A correlate to the first cross-section that you have there?
A Yes, on the left side.
Q And then A prime is the second cross-section?
A Yeah, it's -- A prime is just the other side of the cross-section.
Q And what about the red box? What is the significance of the red box?
A The red box just identifies the location of the Bell Canyon formation.
Q So this is an outline of where the Bell Canyon formation falls within these cross-sections?
A Within those -- within those two wells.
Q And what is your conclusion that you draw from this slide?
A The conclusion. The -- the porosity in -- in this cross-section that's shown in the kind of red

pinkish curve, and when you see a movement of that curve to the left, that means that there's high -- there's going to be higher porosity in that area. And what's -- what's done on the right in each -- each well, where you see the column with the blue, thick units identified, those are -- are thicknesses of -- of sediments that are greater than 14 percent porosity.

Q So you filtered out anything below 14 percent or Chevron filtered out anything below 14 percent?

A Greater than 14 percent. Greater than 14.

Q Oh, greater than 14. This is why I don't do math. Less than, greater than. Challenging.

But these dark blue areas indicate units that are favorable for injection based on their porosity levels?

A Yeah. The lighter color blocks are really greater than 14 percent. The darker blue is for actually greater than 18 percent porosity, which is a higher threshold. But it still shows that in both -- you know, both of those wells, we see, you know, a lot of neck thickness of porosity. Which -- and Bryce will talk about this later. But when we look at model of -- of injection in the -- in the DMG, that porosity is really a key fact. And that's why we come in and we looked to identify areas where we want to target placing the SWD wells.

Q And just for the record, the Papa Squirrel well is about halfway down or a third of the way down the line from A to A prime?

A Right over here.

Q So let's turn to the next slide then, unless there was anything else on that slide you wanted to touch on.

A No, that's all.

Q So this next slide is page 105. And this slide, again, are these the same two logs that we reviewed on the last time?

A They are the same two logs. Same two wells.

Q And so in this leg you're just focusing further down in the geologic formation?

A Right. In the upper Cherry -- Cherry Canyon.

Q And did you undertake this study again to understand the net porosity in this area?

A Yes, I did.

Q And what was your conclusion?

A This is still favorable. It's -- it's less favorable, but it's still favorable.

Q This area would still take water in theory?
A Exactly.
Q Is there anything else you wanted to mention about this slide before I move onto the next slide?
A No, I think that covers everything I wanted to cover on the slide.
Q So turning to the next slide, this is the geologic analysis that you undertook for the Severitas well to understand the porosity in that area; is that right?
A That is correct, yes.
Q And this is page 106 of 267. And so can you orient the Commission again? What is the inset map here on the righthand side of the slide?
A The inset -- inset map shows -- is a net porosity map that's color coded for an area that covers this development area that's known as Harris, New Mexico.
Q And I see on here you have some legends. Worst net porosity, better net porosity. And the shading, the dark purple, does that correlate to worse net porosity?
A Yes, it does.
Q And then this sort of turquoise or greenish blue is better net porosity?

A That is correct.

Q And the Severitas well is approximately halfway between the A and A prime on this?

A Yeah. And the -- and the arrow point is shown pretty correctly. So the point of the arrow is really where the Severitas well is.

Q And do these logs have the same data as the prior logs that we looked at in terms of gamma?

A Yes, they do. And the difference is that these were plotted in Petra. The other -- others were -- we used a different software package.

Q But they contained the same material.

A Same basic material. Just different programming.

Q And what conclusions did you draw from this analysis?

A Well, as -- as Cody Comiskey noted earlier, you know, we -- we've looked at two areas where we had slightly different variations in stratigraphy. One, you know, the -- the stratigraphic thickness of the -- of the Delaware Mountain Group is thicker in the Papa Squirrel area to the east.

It's thinner to the west where the Severitas is. So we would naturally expect that the -- the reservoir character in this well would be less favorable than that in the Papa Squirrel just because of stratigraphic thickness -- thickness variations. It's thinner over here. And we're actually seeing less net porosity thickness in -- in this area.

But from a standpoint of what we're trying to do within, you know, the scope of this -- these two pilot wells, it's important for us to kind of evaluate these areas where we may not have as great a thickness, but at least, you know, crossing some sort of threshold coming from the well before us, and this one does.

Q So if I'm understanding you, your choice of wells is intentional, because you want to test the reaction of these different thicknesses?

A That is correct, yes.

Q And Dr. Ampomah asked Mr. Comiskey a question about the pilot nature of these wells, and it seems to me that at least one answer to that question is that you are trying to go get data from different reservoir thicknesses to enable Chevron to interpret that data?

A That is correct, yes.

Q And then move forward with other projects or not.

A Exactly. And it should give us some insight about what the opportunities are, you know, moving forward in the future. It's also going to give us this data in a collaborative way where we can kind of share in -- with both the OCD as well as other operators and -- and kind of help out with the decision-making process moving forward.

Q Great. Well, we're going to switch gears a little bit and turn to a study that he did regarding DMG productivity in the area of the two wells. So I am going to switch now to page 99 of the materials.

MS. BENNETT: Give everybody a chance to catch up with me. You there?

BY MS. BENNETT:

Q So on page 99, can you describe to the commissioners what this exhibit is and your intentions behind this exhibit?

A Yeah, in -- in this exhibit, this is the -- the diagram on the right and the -- the table that's shown are really part of the C108 application. And -- and what I did was just to kind of combine both components that are included in the C108 application into one slide. It just makes it --

Q And what --

MR. FUGE: Give it a second.

BY MS. BENNETT:

Q One of the primary takeaways I had from this slide was or questions I had was whether there are any DMG, Delaware Mountain Group wells within a half mile of the Papa Squirrel?
A The answer is no.
Q Where are the closest Delaware Mountain Group producers from Papa Squirrel?
A They're -- they're about one and a half to two miles away to the southeast.
Q And will Mr. Taylor be discussing those wells?
A Yes, he will. Yes, he will.
Q Great. And then the next slide, which is slide 100 of 267, is this the same information but for the Severitas well?
A Yes. Again, these are -- these two tables as well as the -- the map are both components that are submitted with the C108 application.
Q And one thing I wanted to ask you about, actually. I'm going to turn back to page 99. Chevron operates wells within the Papa Squirrel AOR; accurate?
A That is correct.
Q And so you have your own wells that are currently in production within the area of the Papa Squirrel well?

A That is correct.
Q And is that true for the Severitas well also, which is on page 100?
A Yes, it is.
Q So Chevron, as part of the pilot nature of this project, you are able to test whether these wells impact your -- "these wells," I mean SWDs -- impact your existing wells?
A Correct. We -- we essentially don't have to worry about going out and asking another operator to -- to monitor horizontal wells in these areas because we have some. And we can evaluate those impacts if they exist directly.
Q So you would have both the -- you manage the existing production wells, but you'll also be able to manage the proposed SWDs?
A That is correct.
Q And again, I think we might have talked about this, but there's no DMG wells within the half-mile radius of the Severitas well; is that right?
A That -- that is correct.
Q Now I want to turn to a slide you prepared about the drill stem tests, and that's page 107 of 267. Give everybody a second to catch up there.
So first of all, what is a drill stem test?

A A drill stem test is a test that's run open hole within a vertical well normally, and which there is a packer that is engaged, and a pressure suction on the well that allows oil or any kind of fluids that are in the units where the packer isolates in -- in the well. And it's able to -- to evaluate both pressures as well as the fluid types that come into the -- into the test -- testing device, the drill stem test.
Q And so what does the drill stem test, what kind of data does it provide you or provide Chevron through you?
A It essentially can indicate to us or any operator whether or what kind of potential there is for hydrocarbons within the zones that you're testing.
Q And these drill stem tests aren't tests that you undertook though; right? They're existing tests?
A These were publicly available drill stem tests. And the way we approach this data gathering was to assess, you know, the -- the large resource of public data available in both areas and determine which -- which drill stem test was conducted within a radius of these wells within the -- the Delaware Mountain Group.
Q And so let's just knock out Papa Squirrel

really quickly. You noted that there were no drill stem tests taken in the DMG within two or three miles of the Papa Squirrel?

A That's correct, yes.

Q And so there was no data for you to analyze there?

A There was no data to analyze. Correct.

Q So how about for the Severitas? What did you find for the Severitas?

A In the Severitas well there were -- there were no DSTs within two miles of the Severitas well. We did have two DSTs within two to three miles of the Severitas well.

Q And were those two DSTs the two that you identified here?

A That is correct, yes.

Q And in your review of the data, what did you glean from the data in terms of DMG productivity in and around Severitas 2 State SWD Number 1?

A Well, the fact that they were two to three miles away told me that -- that basically there's a low risk of impact production in and around the Severitas well.

Q Let's turn now to the structure map that you prepared. And the way I was looking at your -- was

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sort of a -- yeah, looking to see if there were existing wells, which there weren't any. And then looking to see if you could find any drill stem tests on the existing wells, which there weren't any within two or three miles.
A Right. Correct.
Q And then you focused then even on the geology of the area to see what the geology says about the presence of DMG and reservoirs in the area?
A That's correct. So -- so really fundamentally both these slides, what we were trying to do to establish was to take a stab at this question of -- of, you know, the future reserves. What -- what is -- you know, how can you come up with some sort of assessment on how or whether or not there are future reserves within the DMG in these areas. And -- and these were two approaches that we came up with.
We felt that the drill stem test was the preferred way of assessing whether or not existing hydrocarbons are in the area. Because when a -- when the operator drills a well or looking for oil, you know, a drill stem test is -- is a very cheap way to determine whether or not it's worthwhile running casing and producing from that zone.
And then this second map was really designed

to say, "Okay. If I'm an exploration geologist, what would I do?" Well, in the previous slide where we had stratigraphic units shown within the Bell Canyon and the Cherry Canyon formation, we showed that the stratigraphic units seemed to have some sort of continuity across all those areas.

So then the question is, okay. Given the fact that you don't have any obvious stratigraphic pinch outs in these areas, then what else would you look at? And the solution was, okay. I wanted to take a look at the structure map in both of these areas, and that's what I did.

Because the structure map would define -- if there were no pinch outs of stratigraphy, then you would have to have some sort of tracking mechanism in addition to that, and that would be structural closure. And the bottom line in both of these series, I didn't see them.

Q Thanks for that. You know you and I talked a lot about this because -- structural closure and trapping is, you know, over my head. But what I appreciated about it was that you went -- you were using actual information to test your theory about the lack of DMG reserves in this area.

A Yes, I got to be an exploration geologist, and yeah, so.

Q Yeah. And I really appreciate what you just said about the drill stem test, because I don't think before today I actually understood that, that that is a mechanism by which operators consider whether it's worth it to continue to explore for -- it's a preliminary step in an exploration for reserves; is that right?

A It's a very cheap preliminary step to make that evaluation, yes.

Q And so if that -- that's incredible. Thank you.

On these, we've talked a lot about traffic in the area. And you know, you ad I talked about an inverted bowl. And is that sort of where the hydrocarbons would be trapped such that there could be future reserves in this area? Would that be an indicator of that?

A Yes, that's correct.

Q And did you see anything that would indicate the potential of unknown reserves in these two structure maps?

A No, I did not.

Q Did you see any fault in the lower containment zone?

A No. No faults at the -- at the level of Bone Spring limestone. We evaluated seismic data in -- in both areas and determined that there were no nearby faults within a two-mile radius of -- of the Severitas and the Papa Squirrel well.

Q How about any faults in an upper containment zone, which is the little Lamar limestone? Were you looking for faults there too?

A We did. And the challenge in Lamar kind of touched on the challenge with that, because if you remember in the Castile formation where you have anhydrite, you also have salt in -- in these areas. And there are some problems with depth conversion of the seismic data when you have these velocity changes that occur laterally within the section above the zone that you're trying to map.

The zone we're trying to map is determined -- it's really the Lamar limestone. Do we see faults and seismic data with the Lamar? Because of these velocity problems what we have as a -- as a result of the -- the salts and anhydrites in the Castile.

We get some anomalies that are really difficult to sort through, and you have to have really good velocity data to -- to make accurate interpretations of that -- that surface. But from what we could tell, given all that, we don't have any faults in -- both areas.

Q And will one of Chevron's other witnesses today talk about the Lamar limestone and the amount of pressure it would take to break that or the sufficiency of the Lamar as a containment zone?

A Yes, Bryce Taylor will discuss that further.

Q Great. So to summarize, in your opinion is the Papa Squirrel well, does it have the potential to -- in your opinion and just focusing on the slide and your work with Chevron, does it have the potential in your opinion to negatively impact correlative rates?

A Not in my opinion.

Q And in your opinion, do you think that there is a low likelihood of hydrocarbons in the DMG within the AOR of each of these two wells?

A Not in my opinion.

Q But it's your opinion that --

A It's my opinion that that is correct, yes. Sorry.

Q That there is a low likelihood?

A That there is a low likelihood.

Q And that's based on the drill stem tests?

A The drill stem test coupled with the -- with all the structural closure and the fact that there's continuity in the stratigraphic units across both areas.

Q And the continuity in the stratigraphic units, if there was a pinch out, that would be a place where hydrocarbons could collect?

A That's correct. And the other factor is that we have a number of wells that then drill through, you know, in these areas, and we haven't today seen any evidence that there's -- from those wells that there's potential for -- for hydrocarbons.

Q Not to dwell on the stratigraphic uniformity any longer, but I did just think of a really great analogy for me, which is a stream, and the fish tend to gather, you know, in eddies or along the bank or rocks within a stream. And so if the hydrocarbons are fish, we're looking for some anomalies in the stream where they might gather and enjoy their day when we go fishing?

A That might be an analogy, yes.

Q Well, it works for me. And I'm going to go fishing this weekend now that I've thought about it.

Any last things you'd like to say or tell me not to draw analogies ever again?

A No, I really don't have any other comments to add.

MS. BENNETT: Thank you very much.
And with that, I would move the admission of Exhibits A and B, which are the applications and the included C108s. And I would also move admission of the slides numbered 98 through 108.
MR. FUGE: Any objections?
They're admitted.
(Exhibit A, Exhibit B, and Exhibit 98 through Exhibit 108 were marked for identification and admitted into evidence.)
MS. BENNETT: Thank you.
MR. FUGE: Mr. Tremaine, do you have any questions for the witness.
MR. TREMAINE: I do have some questions. Thank you, Mr. Chair.
EXAMINATION
BY MR. TREMAINE:
Q Mr. Merrifield, I'm hoping to clarify a response that you provided to Ms. Bennett. You used very specific language when you were talking about the produced water injection. I believe what you said was Chevron was not targeting the Brushy Canyon for produced water injection. Is that correct?
A That is correct, yes.

Q Is it Chevron's expectation that produced water that is targeted to be injected into the Bell or the Cherry Canyon, will a communicator migrate down to the Brushy Canyon?

A At this point in time, we do not think so. Okay. Now, the -- the part of the surveillance process program we've been putting together --

Q Believe it or not, it's better than it was.

A -- is to further evaluate their -- their questions about reversal and frac gradient as we get deeper in the DMG. And that program hinges on the sonic data that we're going to be collecting in these wells.

And we're also going to just -- just to get into detail a little bit, we're going to be collecting monopole, dipole, and sonar data. We'll also be collecting triple-combo data as well throughout the Bell Canyon, Cherry Canyon, and that -- that one upper portion of the Brushy Canyon and we drill through. And then we'll also be collecting the DFIT data.

Now, all of those will be coming together with several different analyses on frac gradients. And -- and that is from -- in my opinion, it's the most exhaustive approach. It's really important to take that -- gather that kind of data to make the most accurate assessments of frac gradients in these two wells.

Q Thank you. And bear with me. Likewise, I'm not a geologist. So when you are done with the DFIT, when the lower zone is cemented off, how are you going to be able to tell whether injected produced water in the higher zone migrated down to the Brushy -- to the Brushy Canyon?

A We should have some indication with the analysis of the data. So the data should tell us something about frac gradients and whether they linearly increase with depth or if there is a reversal. So there should be a theoretical indication before, you know, any migration fluid occurs, it -- but it will tell us about the possibility.

Q So you're going to see it before or as it happens rather than after the fact?

A It's -- we're going to -- yes, correct. It's -- it's really part of the data analysis. Now, mind you, the -- you know, after we collect the data, we're going to start injecting. Okay. There's going to -- before any -- any potential migration were to move into the Brushy, it would have to collect some sort of threshold pressure and volume that we've injected into the Bell and Cherry before we see any

injection of migration downward into the Brushy. So I think there's going to be time where we would determine -- could determine from a theoretical standpoint that's a possibility or know it's probably unlikely.
Q Thank you for that clarification. One more quick question here, Mr. Merrifield. In terms of the assessment of reserves from the DMG, was that focus on the Bell, Cherry, and Brushy Canyon zones? Or is that --
A So yes, we looked at -- in fact, I -- the search criteria was very exhaustive. I looked for Delaware Mountain Group. I looked for Delaware Canyon, Cherry Canyon, Ranchy Sand. I went through all of the possible names to kind of extract from the AHS database to assess that.
Q And did that include the Lower Brushy within Avalon or just focus on the three zones we discussed?
A It -- it included all of Brushy. And you know, I did not get into that one. No, I did not. 'Cause the -- the whole assumption there is that I was going to carry it down to the -- which is really the base of the Delaware Mountain Group. And then I stopped at that point.
Q Are you aware of any reserve assessment that

was a problem at any other operators?

A No.

MR. TREMAINE: No further questions.

MR. FUGE: Ms. Hardy?

MS. HARDY: I do have a couple of questions.

MR. FUGE: If you could just come up, it will make it easier to hear.

MS. BENNETT: I can switch too if you want.

MS. HARDY: That would be great. Thank you.

This will be quick. Sorry.

EXAMINATION

BY MS. HARDY:

Q Mr. Merrifield, I just have a couple questions for you. With respect to your well bore diagram that we were looking at, which was page 101 using the file page number, you had discussed with Ms. Bennett the DFIT test and how they will impact or how they will be performed at Brushy Canyon.

A Yes.

Q Will the Brushy Canyon DFIT be performed only in the open-hole section?

A It will not be performed in the open-hole

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section. And -- and maybe that was not clear. It -- it will -- DFITs, the diagnostic fracture injection test will be done through case toll. And that's -- one of the advantages of doing that is that the chances of success are greatly enhanced when you have packers that are actually in contact with --

Q Then looking at your slide 108, which is the structure map, what is the contour interval on those maps?

A I think it's 100. It could be 50 feet. It's 100 or 50 for sure.

Q 100 or 50?

A Yes.

Q Is it correct the down dip is to the right?

A It is correct.

MS. HARDY: Those are my questions.

MR. FUGE: Dr. Ampomah, do you have any questions for the witness?

DR. AMPOMAH: Yes, I do. So let's go over the C108.

MR. MERRIFIELD: Okay.

DR. AMPOMAH: So on page 23.

MR. MERRIFIELD: Okay.

DR. AMPOMAH: You show the schematic of the -- well.

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MR. MERRIFIELD: Okay. This is a -- this is one of the abandoned ones.

DR. AMPOMAH: Yeah, one of them.

MR. MERRIFIELD: I remember this. Yeah.

DR. AMPOMAH: So looking at this, how they procced it, do you believe that it was plugged in a good way to prevent any potential complication with the oil breaching?

MR. MERRIFIELD: So I don't recall the exact date. I'm looking at the way that they plugged this well. It's an -- it's an older plugging approach. And -- and the reason I know that is because they use kind of these intermittent cement plug and then match --

And then it -- that is a standard approach back in the -- kind of the 70s or the 80s and sometimes even into the 90s depending on what state you're in. They -- they will still allow. Today, that's not, you know, the best way to do it, but it was acceptable at that day and time.

Now, having said that, we were talking about mud slurry. That's usually a thick -- slurry usually. So it's -- it is still -- So yes, I -- it is an approved approach, but historically, I think, you know, that there's historical context.

DR. AMPOMAH: So it's still workable?

MR. MERRIFIELD: It's still what?

DR. AMPOMAH: Is it workable? Like you believe there should be some sort of highlight on this particular well?

MR. MERRIFIELD: All I'm saying is that it's -- it's not the standard practice. But bentonite is a very impermeable material. When it's mixed with mud, basically the mud portion of that well as well as the cement portion are considered impermeable barriers within that well.

DR. AMPOMAH: So let's talk a little bit about --

MR. MERRIFIELD: Did that answer your question?

DR. AMPOMAH: Yeah. I'm sure OCD knows more to make sure that there will be no problem with that. And I just wanted to know that. On page 10 of the C108 1B application.

MR. MERRIFIELD: Okay.

DR. AMPOMAH: So you have on -- saying Brushy Canyon is included as a potentially -- the Brushy is not intentionally targeted for injection. Now, but you're also going to do a DFIT in this project; right?

MR. MERRIFIELD: Correct. That's -- that's the key point.

DR. AMPOMAH: So I just want to know is there no any other alternative? Other than more like bridging the Brushy Canyon, knowing very well that you are not going to do any injection. So is there any other alternative to collect the data that you're looking for without actually performing the DFIT in this position?

MR. MERRIFIELD: The purpose of the DFIT and -- is to really calibrate the interpretation of the frac gradients that are determined from loss. And the only way that you can do that is by having some type of injection test. A DFIT in my opinion is the best approach to get the most accurate and -- and best chance at getting data than any other data that you can do.

But all the data that you can -- in order to -- to calculate the frac gradients, you have to -- you have to have some sort of injection test. And -- and Bryce will touch on this a little bit later, but he -- what he'll show is, you know, what the pressure buildup looks like and what it comes back down to and -- and what part of the curve you actually have to measure in order to assess, you know, what the frac closure stress or fracture is when you -- when you run that test.

DR. AMPOMAH: So are you saying that let's say the DFIT that you're going to do in this hurricane land in the creek formation. There was two.

MR. MERRIFIELD: Mm-hmm.

DR. AMPOMAH: You don't have right now datapoints to be able to calibrate your entire project gradient, but you still have -- can you do a DFIT in the Brushy?

MR. MERRIFIELD: What we'll have after we collect this data is we'll have DFIT data in the Brushy Canyon, the Cherry Canyon, and the Bell Canyon formations. We'll have a continuous curve of what the frac gradient looks like.

DR. AMPOMAH: Yeah. But my --

MR. MERRIFIELD: And to calibrate that, we have to have certain datapoints that require some sort of injection test. And the injection test that we're proposing is a DFIT.

DR. AMPOMAH: So you said you have to do how much percent of -- if we are not going to use this formation for injection, why do we have to perforate it, you know, in the first place, and then

coming back to fill it out? You know, so that is my
concern.
MR. MERRIFIELD: Yeah. So the reason
why we have to -- I think I understand where you're
coming from -- is we actually have or are forced into
injecting into the formation.
So we actually have to cut a hole
through casing and inject into the formation and
monitor the pressure buildup and decline in order to
gather this datapoint that's going to be used as a
calibration point. There's no other way to do it from
my standpoint. I don't -- I don't know of any other
way to do it. You could do it open hole.
DR. AMPOMAH: Mini-frac, yeah.
MR. MERRIFIELD: But it -- but what I'm
saying is the chance of success with the mini-frac of
getting the data is about 40 percent. Okay. And --
and with this, it's about 95 percent.
DR. AMPOMAH: So, like, 104 actually?
MR. MERRIFIELD: Yeah. Yeah.
DR. AMPOMAH: So page 104 on the
application. I want to know how many wells you used
in analyzing the petrophysics to obtain results.
MR. MERRIFIELD: Okay. Yeah. And so
the -- the amount of wells, I don't have that number

in hand. But the -- we had probably on the order of at least a hundred datapoints to create that map that's on -- that's color-coded on the righthand side right there. At least a hundred. Maybe 200. Maybe 500 to create -- do you want me to point at it?

DR. AMPOMAH: No, I can see.

MR. MERRIFIELD: Okay. Yeah. But the -- all those datapoints are not shown here.

DR. AMPOMAH: So you show a porosity 20 percent going in there, but probability 0.4 to 3 so my question is what does it show? Or how did you compute permeability?

MR. MERRIFIELD: How -- how did we compute permeability? We did not actually calculate permeability. So in -- if you -- in the Delaware Mountain Group, because these are sandstones, there is -- there are a number of authors that have evaluated the permeability-porosity relationship and, you know, plot how linear that relationship is. But we have not -- we did not go in and calculate permeability in -- in these for our study.

DR. AMPOMAH: So on page 98, you talk about how the two wells, there is an extent of geology between these two wells, two locations. Right. We talked about that from the other testimony. Now, you are using upper relation to --

MR. MERRIFIELD: Yes, exactly.

DR. AMPOMAH: Let me ask. So do you have any plans to offer a quarry program to be able to get the actual call because you want to build a database right now really dependent on more or less a correlation?

MR. MERRIFIELD: We -- we did have that in some of our initial evaluations of all the surveillance that we were going to gather. But because of -- the coring I think ended up being a minor component just because we did not feel that that would add as much value as the cost, and it was really just to -- when we evaluated all the different surveillances that we were going to do, we just felt that was a lower priority. Yeah, we did -- we did entertain that. That -- I'm letting you know that.

DR. AMPOMAH: But why would that be a low priority?

MR. MERRIFIELD: It was a lower priority. That's all.

DR. AMPOMAH: Yeah, but we want to know how Pinon water formation was, had it done just relying on no map relation, no --

MR. MERRIFIELD: Well, see part of the

assessment was we actually pulled the existing core data that was available from the DMG and incorporated that into the analysis.

DR. AMPOMAH: Thank you. I appreciate that.

MR. MERRIFIELD: Yeah.

DR. AMPOMAH: Help me understand. On your well design for the Papa Squirrel well.

MR. MERRIFIELD: Mm-hmm.

DR. AMPOMAH: So I'm trying to correlate that to the well correlation that you're showing on page 104. Is the Papa Squirrel well the one that -- that one is in the total vertical depth; right?

MR. MERRIFIELD: Is it -- I'm sorry. What was your --

DR. AMPOMAH: Total vertical depth.

MULTIPLE SPEAKERS: Total vertical depth.

MR. MERRIFIELD: Yes. Right.

DR. AMPOMAH: Yeah. So I see the Bell Canyon is about 4,655 feet.

MR. MERRIFIELD: Uh-huh.

DR. AMPOMAH: Now, when I cross-check that to you, the well correlation that you have on

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page 104. So from A to A prime, you have your well. It's going to be in the middle. And maybe the well correlation is in a different depth to me?

MR. MERRIFIELD: It -- it is. It's subsurface 2DD.

DR. AMPOMAH: Okay. I just wanted to clarify that.

MR. MERRIFIELD: Yeah.

DR. AMPOMAH: And maybe if we can -- because it's not --

MR. MERRIFIELD: It's not. And that's -- you know, that's something that should have been caught, but it wasn't.

DR. AMPOMAH: Because I was totally lost.

MR. MERRIFIELD: No, valid question.

DR. AMPOMAH: I do have further questions. So how in your application you showed on a structure map that you did place all the well correlations. But I don't see that on the side, so I don't -- base, you know, but I just want to know why did you not include any interpretation from the seismic?

MR. MERRIFIELD: The -- the question about seismicity and showing that is -- really has to go through IP review process. And -- and we, you know, in the process of going through this, I felt that interpretation, it was based upon interpretation of our SME.

And to go through that, we would probably -- there would have been a lot more that needed to be addressed other than just this group. We would have had to been -- gotten into a lot of detail on that evaluation. And we just didn't see that that added as much value.

DR. AMPOMAH: So you took the -- You were not able to identify any -- in the Castile. Now, when you talked about how there was some sort of anomaly because of salt and then the presence of anhydrites in there, so you were not able to build a very good velocity forward to really interpret those.

MR. MERRIFIELD: Right.

DR. AMPOMAH: Now, I just want to know, did you try any different options to see if there are no geological features that could impede any potential pathway?

MR. MERRIFIELD: Other than the seismic data? Is that what you're saying?

DR. AMPOMAH: So for the seismic data, there are multiple options that you can run. You see

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where under any given seismic faults, anything. So I'm just asking just a normal interpretation. Did you go further to use attributes?

MR. MERRIFIELD: We -- yeah. And the person that did this actually looked at a couple of different ways of looking at the data, but it -- it boiled down to one fundamental criteria, how you define fault using seismic data.

And that there -- it's a very traditional way of looking at it, and that is if you really need to be able to define separation of stratigraphic units across a discontinuity that can be seen at the scale of the observation that you're making.

'Cause it's that discontinuity between two horizons across some plan of discontinuity, which is defined as a fault, where you actually see separation of layers. So he was really looking for that characteristic to define a fault.

MS. BENNETT: And I don't mean to interrupt here, but Mr. Comiskey will also be able to address some of the questions on seismicity if that's useful for you later today as well.

DR. AMPOMAH: Yeah, I was mostly talking about the seismic interpretation, not seismicity. I know that one. Yeah.

Can you talk a little bit about the stimulation? Do you plan to do stimulation in this well?

MR. MERRIFIELD: After we complete the well, after we drill the well and then we run casing and then we perforate the casing and then we set the tubing in the packer in the well and we put a well head on it, we will conduct an acid job.

And that really is to clean out, you know, the perforations, clean out anything near well bore so that when we actually go in and -- and inject into the formation that we know that the -- the formation is as clean as possible and the near well bore is as clean as possible to enhance injectivity. So that's going to be, you know, the primary reason for doing an acid job. And by -- when we say stimulation, an acid job is a form of stimulation.

DR. AMPOMAH: Thank you.

MR. FUGE: Mr. Bloom?

MR. BLOOM: Yeah, just a couple quick questions about the location and some of the wells. You mentioned I think with respect to the Severitas well that there were three nearby Bone Springs wells?

MR. COMISKEY: Yes.

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MR. BLOOM: And do you do any extra sort of particular monitoring of those wells in your proposal?

MR. COMISKEY: I'll have to defer that to someone later, I think. Surveillance plan.

MS. BENNETT: Mr. Comiskey will be discussing the data and monitoring plan in detail.

MR. BLOOM: Yeah, I was interested in the monitoring too.

And then I don't know if this would be a question for you or perhaps someone else well. But regarding the location of the Severitas well, looks like that's in the SCADA. That's the state federal unit.

MR. COMISKEY: Yes, it is.

MR. BLOOM: Yeah. I don't know if that unit's formations include the salt water disposal target formations. Do you know?

MR. COMISKEY: So this is within the SCADA unit. This well is actually going to be located on State Land Office land. And it's -- it's from -- from our assessment -- land assessment of this, we -- we have the right to inject into the DMG, if that's your question.

MR. BLOOM: That's where I was going.

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Yes. And similarly if you move that, I think there was a mention of a micro-move of a couple hundred feet?

MR. COMISKEY: Mm-hmm.

MR. BLOOM: You'd still be on State Trust Land?

MR. COMISKEY: Yes. Yes.

MR. BLOOM: You may want to check with the Land Office and see if that unit actually includes the DMG formation. And I believe -- have you filed that application for the easement yet, salt water easement with the Land Office?

MR. COMISKEY: I don't know if we have or not to be honest. Well, but I -- but I will tell you this. The person that is evaluating that is actually over at the State Land Office right now having a discussion with them about some -- some things.

And I know that -- that the question that you're asking is -- is something that -- and he -- he's aware of both locations. I've been having these -- these ongoing discussions with him about this and -- and he understands fully the need to have the -- own the right to inject disposal water within the DMG on either location.

MR. BLOOM: Yeah. Thank you. And you know, that might be a little bit beyond the scope of this today. But I just wanted to ask about those practicalities there so.
MR. COMISKEY: Exactly.
MS. BENNETT: Thank you.
MR. BLOOM: Yeah. Thank you for the presentation. No further questions.
MR. FUGE: And I've got no questions for the witness.
So you may be excused.
MR. MERRIFIELD: Thank you.
MS. BENNETT: Thank you.
Mr. Chair, I did want to -- and I should have been -- well, I don't need to with Mr. Comiskey. But with Mr. Merrifield, I would like to reserve the right to call him for a rebuttal witness if necessary.
MR. FUGE: Okay.
MS. BENNETT: Thank you.
MR. FUGE: I think in the interest of time, and I think that the next witness will be relatively long. I say we adjourn for a relatively brief-ish lunch break and resume at 12:45.
(Off the record.)

MR. FUGE: Make sure I've re-initiated the recording. Good.

I think we're ready to have you call your next witness.

MS. BENNETT: Thank you very much. And Mr. DeBrine is going to handle the next two witnesses.

MR. FUGE: Okay.

MR. DEBRINE: Good afternoon, Mr. Chair.

Chevron would like to call its next witness, Jason Parizek.

MR. FUGE: Can I ask the court reporter to swear in Mr. Parizek please?

THE REPORTER: Please raise your right hand.

WHEREUPON,

JASON PARIZEK,

called as a witness and having been first duly sworn to tell the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

MR. FUGE: Thank you. You may take a seat.

EXAMINATION

BY MR. DEBRINE:

Q Please state your name.

A Jason Parizek.
Q Who do you work for, Mr. Parizek?
A Chevron.
Q How long have you worked for Chevron?
A Just over ten years.
Q And if you could for the Commission just give a shorthand background with regard to the evolution of your duties and responsibilities for any jobs with Chevron during that period?
A Yes. I started off working in San Joaquin Valley, California, as an acid development geologist. My duties there were planning and overseeing execution of both horizontal and vertical well bores.
Following that, I went out to a field office working with the production operations group on technical team. Duties in that role were setting up and establishing reservoir management and surveillance programs for both a sour gas disposal project and water injection projects. I was also responsible for overseeing and planning side tracks of both vertical and horizontal wells.
2018 I moved out up to Midland, Texas working the Permian Basin. I started off working in the production office group as a technical team geologist. Duties on that team involved evaluating

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some of our deep disposal wells, looking at different performance between the wells. I was responsible for a re-frac project that we conducted in the basin and oversaw some technology projects such as gas reinjection.

I'm currently working as a development geologist in New Mexico. Have responsibilities in that role involved planning and overseeing execution of horizontal wells.

Q Could you give a brief summary of your educational background?

A I have a master or a bachelor's degree, a Bachelor's in Science from San Diego State University. Graduated summa cum laude. And a master's degree from San Diego State University. Both of them are in geological sciences.

Q Have you previously specified before the New Mexico Oil Conservation Commission or Division?

A I have testified before the Division in February of 2020.

Q Were your credentials accepted as a matter of record --

A Yes, they were.

MR. DEBRINE: We would tender Mr. Parizek as an expert in petroleum geology.

MR. FUGE: So tendered.
BY MR. DEBRINE:
Q Are you familiar with the applications that Chevron filed in these two cases?
A Yes.
Q Are you familiar with the two saltwater disposal wells that are the subject of the present project?
A Yes.
Q Before we start reviewing the exhibits you prepared as part of your study, if you could give the Commission just a brief summary of what inquiry you undertook and the subject of your testimony today?
A Yes, my testimony will be exploring in further detail some of the case studies that were identified in the map that was referenced I believe in the opening statements regarding one of the products of the 2016 work group that was taking place.
What I'm going to show is that several observations of looking at watercut changes can be explained in different ways by establishing some of the understanding that we have developed with DMG and fracture driven interactions between various ventures within the Permian Basin.
With those learned, we can now apply those

-- that same level of assessment back to those case studies and potentially come up with different or more -- more robust interpretations for the root cause.

MR. DEBRINE: And to the benefit of the commissioners, the exhibits we're going to discuss with Mr. Parizek start at page 109. If we can turn to the first slide.

BY MR. DEBRINE:

Q Could you just briefly explain what this slide represents and the work that went into it?

A Yes. This slide really the -- the core of the slide is I want to demonstrate that watercut alone is not a definitive test for salt water disposal's interference of producing wells.

So just some of the background in going into this. I mentioned the 2016 work group. That work group shared observations of both Delaware Mountain Group production wells and Avalon production wells that were seeing increased watercut over time.

And on the map on the right side, I've got a -- an example of what -- what those maps had looked like that was within that slide deck. And that slide deck is I believe Exhibit 8 in the -- the OCD's exhibits.

But on that -- on that map, you'll see kind of a locator map. And within that, there are sections that are highlighted in purple or red. And those sections represent areas that were suggested to have had DMG interactions with underlying Avalon producers.

And the way that they're identified, if you look at the circles, you'll see a larger light-colored circle and kind of a smaller dark circle. Well, the smaller dark circle represents a cumulative watercut over the life of the producing well and the larger light-colored circle would represent the last six months' watercut.

And when you would see an increase in the last six months' watercut over the lifetime watercut of the well, that would indicate that that well is now producing a higher watercut than it was historically, suggesting that something has changed reading that -- that production change.

Q So is it fair to say that your study was to look into whether there were other potential causes to explain the increased watercuts that were reported in those case cuttings?

A It was -- it was part of the work that I've done. And I'll show in future exhibits that we've learned a lot about our development areas that are located proximal to the example I've shown. And we would apply those learnings and revisit in some of these cases and -- and come up with different, and I would argue in my opinion, stronger hypotheses as to what's going on with the watercut changes.

Q If you could turn to your next slide -- what does this represent?

A The map shown on this exhibit represents a locator map for the case studies that I had evaluated as part of this assessment. And it's a subset of them. Also shown on the -- they're represented by the colored circles, and I'll describe those shortly.

Also shown on this map in stars, yellow star represents a location of the Papa Squirrel saltwater disposal well that's part of this case. And the blue star on the left side of the map represents the location of the Severitas 2 State SWD 1, also part of this -- this case.

And the pink or purple polygons that are scattered across this map represent locations or areas that Chevron operates.

The colored circles shown on this map -- I've got a legend off to the upper right. But the -- the green circles represent an area where we've identified Wolfcamp completions affecting the Avalon and resulting in similar observations that we had seen in the previous exhibit that I've shared regarding Exhibit 8 that the OCD has entered.

The blue circles represent areas where Chevron is operating Avalon wells either directly under or adjacent to Delaware Mountain Group saltwater disposal. And we are not seeing any impact from those operations.

The red circle represents an area where there is identifiable geologic features that trend between Delaware Mountain Group injectors and Delaware Mountain Group producers that may have a driver on why some of the -- the potential communication was seen in those areas.

And then lastly, the orange circles represent areas where there are geologic features that trend between Avalon producers and Delaware Mountain Group saltwater disposal wells that again could -- it may indicate why some of those observations were made.

Q Let's turn to the potential exhibits prepared for inspection and study. The first one is just identified in the next slide, "Wolfcamp Completions Affect Avalon Production." Just the title and the actual first exhibit representative of these studies on page 112, "Wolfcamp Completions Result in Avalon Production Interaction."

If you could explain for the Commission what you did in your study and what's represented by this exhibit?

A Yes. Chevron operates in the vicinity of the Papa Squirrel saltwater disposal well we're proposing. We operate several sections that are fully developed with Avalon producers. And those Avalon producers in the northern part of Salado Draw have produced for three to four years from the time we drill till the time I'm showing on this slide with very stable production traits, very stable declines.

We've seen predictable gas -- through the time, the life of those wells. And the only particular upsets that we've seen with those well during the production periods were when were developing an offset add directly adjacent to those wells. We would typically see fracture-driven interactions that would result in a short-term gas-oil-ratio trend change or increase in water production.

So in roughly 2019 into 2020, we started to see pretty significant changes in our -- our Avalon wells. And -- and by changes I am referring to the diagram that's on the right side of the -- the exhibit here. If we look at -- at that diagram, what we're showing here is both oil production rate and the gas oil -- producing gas-oil-ratios for a sample of the Avalon producers on the northeast side of our Salado Draw development area.

Q And what colors are represented in that chart for each?

A The green circles represent the oil rate, and the yellow circles represent the solution gas-oil-ratio. What you'll observe on here as I discuss is there's been relatively consistent or let me say stable declines through the oil rate and increases in gas-oil-ratio. What we observed at -- at that time was increases in production.

If you'll look at where the vertical dash black line is on that plot, and this is prior to us really understanding what was going on. We started to see significant increases in oil production and significant decreases in gas-oil-ratio.

These Avalon wells are approximately 3,000 feet TBD shallower than our Wolfcamp pads. And at the time of the study, we didn't have a precedent for -- for Wolfcamp completions interacting with Avalon wells.

So some of these, we took an investigation to understand what was going on. We looked at facilities bottlenecking. We looked at a wide spectrum of drivers, but the only one that really correlated to what we've observed here were our underlying Wolfcamp A fracs. And the -- and the frac date is shown by that vertical dashed black line. So that was our first -- our first indication that we had an interaction.

Following that, I've got another diagram here shown on the left -- the lower left corner of the slide. Practically 3 miles west of -- of the first example, we had another pad. This is our second pad of Wolfcamp A wells that was being completed in the area. And we observe again another interaction in those Avalon wells that's highlighted here in the lower left corner.

So let me describe what this chart represents. I've got the time on the -- on the X axis and on the Y axis of showing water rate shown in blue and the gas-oil-ratio shown in black. We see a stable decline in producing water rate, but up until the first black line that's shown with a callout that says "Avalon Frac Interaction Event." This was an offset -- directly offset pad where we saw the completions from that pad interacting with this particular well, and the result was a drop in the producing GOR and an increase in the water production.

You'll see another stable decline from that first event down until the point where there's a vertical red solid line and then a second vertical dash line. What this window represents is the start to the end of the Wolfcamp A completion that was being conducted below the -- this Avalon well.

So this is two examples. Following this, we had strong hypothesis that these Wolfcamp completions were interacting with Avalon. So we took a surveillance -- we conducted a surveillance study on a third pad where we showed it in two Avalon wells. We ran down whole memory pressure gauges.

We conducted water samples from both the -- predicted the Avalon well as a baseline. Collected water samples from an offset Wolfcamp pad as a baseline, and we took our water samples from our completions. And what we observed when that underlying Wolfcamp A well or the pad was completed, 2,000-psi increase in one of our Avalon wells.

We saw the water chemistry change from the time that -- from the time prior to the completion to during the completion and then reverted back to this baseline after the completion. So we -- we then had, again, more data now that supports this hypothesis

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that our Wolfcamp wells were interacting with Avalon.

Q Could you turn to your next exhibit on page 113? It's talking about "Wolfcamp Completions Have Extended Periods of Water Influx in Nearby Avalon Wells." And what did you do for this study in order to reach these analysis and conclusions?

A Yes. So I've got on the bottom righthand corner just a locator map showing the -- the development, the Salado Draw development area just in the vicinity of where we were observing these Wolfcamp A interactions with our Avalon wells.

And highlighted in the blue rectangles, each of those blue rectangles represents an individual pad of Wolfcamp A wells where we have seen an interaction with the overlying Avalon wells. And the only reasons that -- that 13 and 24 aren't highlighted is that they were completed after I conducted his study. So I have not evaluated any -- whether those -- those pads have interacted with Avalon.

At the top -- at the top half of this exhibit, I'm showing three different production plots. And this is again a sample of -- of Avalon wells from across our -- our field as -- as highlighted in the bottom right locator map.

But on the spot, again, the X axis is timed,

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and the Y axis represents in blue, water rate; in red, gas rate; and in green, the oil rate. And you -- looking at these I'll kind of walk through one of them.

Looking at the one on the left, you'll see a very subtle increase around the -- the first callout that says "Avalon Frac," the left of the two. There's a small increase in the water change. And this represents the pad of Avalon wells that were completed two well spaces over from the -- the well that's shown here or two pad spaces over.

The second Avalon frac callout represents an offset Avalon pad that was fracked. You'll see a more significant increase in water production, a drop in the producing -- in the gas production, and then an increase in oil production after the -- the well recovers from that frac-driven interaction.

But we'll also refer to those as fracture stimulation interference, FSI or FDI. We're using those. I'm using those terms analogously.

Q And you may have covered it, but which ones are you referring to when you're talking about water? I mean which color on the graphs?

A The blue. So the water -- the water rate itself, the water production rate is blue. But when I refer to the water cut, what I'm observing is that the oil rate drops down to roughly the zero line as the water rate increases from the base line. So that would have indicated that the water cut's increasing at that point.

So I've stepped through the two examples from Avalon fracs. Now I want to show that the Wolfcamp fracs are the next two vertical lines on this plot. And both of those -- the first Wolfcamp frac figurative interaction that we observe, we'll see an increase again in -- in the -- the water production rate in blue and the oil production rate in green. And again, that well recovers back to a baseline within about six months, just estimating based on the -- the graph.

And then lastly, if you move over to roughly where it says Year 6, you'll see that -- that next Wolfcamp A completion that took place resulted in an increase in water production in this well. But this increase in water production rate is extended at least nine months based on the data that's shown on this plot.

And that's really the key that I want to demonstrate with these plots here is if you look over to the middle plot where that Wolfcamp A frac is shown around Year 5, you see that production upset or that change in water production rate extends almost a year on this plot to the end of the data.

And lastly, in the -- in the last example, again, that -- that that water rate increases for the -- the limit of the data that's shown on this plot.

So the key to -- the key to what I'm showing here is that the fracture-driven interactions or frac interactions between completions and offset wells are generally short term in duration, that these Wolfcamp interactions that we've observed and kind of established are hurting in our area can lead to long-term changes in the -- the water production rate for the -- the Avalon wells.

Q If you could turn to your next slide on page 114. And what does this slide represent?

A This slide represents a reevaluation of one of the case studies that -- that we had taken a look at. And I want to draw attention to the locator map on the left side. What's shown here in yellow highlight on that locator map is the western extent of our Salado Draw development area. And in the middle of Section 21, and I've -- I've got a blue well stick located. And that is the Avalon producer that we're going to be looking at here in this example.

Q So this was multiple other case studies and now Exhibit 8?

A This is -- that's correct.

Also shown on the map in Section 16 north of Section 21 is a blue triangle in the southeast corner. This represents the location of a Delaware Mountain Group saltwater disposal well. And -- and that same -- on the eastern side of Section 16, I've got two well sticks that are difficult to discern.

But the callouts on the top represent those being the locations of one-third Bone Spring well with the completion date shown to be between May and June of 2015. And a stack of three Wolfcamp wells with the completions to be between July and August of 2015.

Looking at the -- the production on the right side of -- of the X axis, we're looking at time. And on the Y axis, we're looking at monthly volumes on the logarithmic scale. Shown in blue on this plot is the water production rate. Green is oil rate. Red is the gas rate for the producer that I have called out on Section 21.

Also shown on this plot is the injection rate in monthly volumes again up for the saltwater disposal well that's shown in the southeast corner of

Section 16. In this example in the documents that were shared in Exhibit 8, the -- the thought or the hypothesis is that breakthrough occurred due to increasing injection rate on that saltwater disposal well, causing the increase in water production in that well located in Section 21.

Given the learnings that we had in our development area, I had taken the completion dates for those third Bone Spring well and those Wolfcamp wells and -- and overlay those onto that production file. And what I've noticed is where that purple vertical line is representing the date of the Wolfcamp A completions, that's when we see the significance change in water production on this particular well.

So while I'm not ruling out that the saltwater disposal well may have been the driver in it, my -- in my opinion, the Wolfcamp A completions is likely a more robust or superior explanation of the -- kind of the -- the two hypotheses that we're looking at here.

Q If you could turn to your next exhibit on page 115, "Wolfcamp completions impact Avalon production." And what does this slide show?

A This is looking at -- looking at the locator map on the left. We're looking at the same general area, but I've moved the subject well one well spacing to the -- to the east of the -- the previous example. Located in Section -- it's located roughly in the center of Section 21.

Also in Section 21, there are two light blue well sticks on the left side representing two Wolfcamp A wells. There are four well sticks kind of in the center of this section representing another set of Wolfcamp A wells and set of purple or I guess purple well sticks on the east side, again representing Wolfcamp A wells.

So I've taken the completion dates for those wells and overlaid those onto a production plot from that particular well. And those are shown with the vertical dash lines on the production plot on the right side of this exhibit.

I want to note that this one is looking at daily rate versus -- rather than monthly -- monthly rate that we have seen on the last slide. So the first pad of -- the first two Wolfcamp A completions that took place don't show a -- a significant step change. You could argue that the -- if you look at the vertical blue dash line that there's a small increase in water production.

But what I really want to call out on this example is that the two pad, the Wolfcamp A wells that are directly underlying that Avalon producer are plotted with a red dash line and a purple dash line. And this well sees a significant change in oil, gas, and water rate coincident with that -- with those completion dates.

And this is similar to the example that I had shown in my previous exhibit. One -- on page 112, where we saw increased oil production following an underlying Wolfcamp A completion.

Q So your bottom line including with respect to the analysis of the Wolfcamp and Bone Spring completions on oil and gas?

A So the -- the key takeaway for my -- for this section is that the observations that we've seen in Exhibit 8 can have alternative -- alternative explanations. Chevron has consistently seen Wolfcamp A completions interacting with our Avalon wells in this particular section of Lea County.

And again, the -- just looking at water cut alone in proximity to saltwater disposal wells, it is -- it is not conclusive in determining root cause. With the additional data we have, we really need to do more thorough examinations of -- to rule out which the leading hypothesis is.

Q Let's turn to the next aspect of your study, which begins on page 116, looking at whether Avalon wells were affected by DMG disposal. And the first substantive slide is on page 117. If you could explain to the Commission what we're looking at here and what conclusions were reached.
A Yes. This example is in a location that's similar to I believe Exhibit 7 that the -- the OCD has submitted. And this is an a -- an area where in 2014 and into 2015, the Bran SWD 1 and the Heavy Metal 12 1 were two open-hole saltwater disposal wells.
And the operator of the -- the green well sticks that were shown on this map where it says "DMG producers," I noted an increase in water production and reached out to the operator of those -- those two saltwater disposal wells, showed them the -- the observations that they had, and they came to an agreement that -- that they were going to shut those wells in due to suspected communication.
Q If you could just identify the location of those two wells that you managed to modify on the map?
A Those two wells are indicated by a blue circle with a cross in the middle of it.
Also shown on this map are two other just open circles, smaller circles. And those represent

two others, the Delaware Mountain Group saltwater disposal wells. One of them was -- one of the SDS 11 Fed 1 was injecting into only the -- the Bell Canyon. Lotos 11 Fed 2 was injecting into the Bell Canyon and Cherry Canyon.

But the -- really the key that I want to demonstrate here is despite the potential communication between the -- the two saltwater disposal wells over to those Delaware Mountain Group producers, Chevron operates Avalon wells that are underlying or between those two locations shown by the -- the DMG wells and the saltwater disposal wells. And we had not seen any indication of water and influx or abnormal production from those underlying Avalon wells.

Q Where are the Avalon wells shown on the map?

A They're shown by the tan or pink color that's in the tan polygon representing the development area.

Q If you could turn to the next slide on page 118 and explain what your study looked at here and the conclusions that you reached.

A This -- this study demonstrates again what I'm going to highlight on the locator map shown on the bottom right of the -- of the slide with a blue --

what we're looking at here is our -- again, our Chevron Salado Draw development area, the wells that are showing up on the map in Sections 15, 14, 13, 18, 19, 24, 23.

These are Avalon producers within that area. The northeast corner of our development area is a saltwater disposal well that was completed in the Bell Canyon and the Cherry Canyon.

Q And just to clarify, Chevron's Avalon producers here are in a different area than what we looked at in the prior exhibit?

A Correct. This is -- this is south of that prior exhibit.

Also on this map is a -- is a SHMax orientation. This -- this is the maximum horizontal stress direction. And it was derived from image -- image logs looking at four-hole breakouts as well as micro-seismic that was conducted in Sections 18 and 19 on this -- on this map.

But what I'm going to demonstrate here is that that saltwater disposal well was active from the time that we drilled those wells all the way to February of 2019. And we were on strike to that SHMAx orientation of that well, and we did not see any indication of production change over the course of that time aside from the known completions that we had in the Avalon wells that are called out on the production plot that's shown on the left side here.

Q You said it runs; correct?

A Yes. What I mean by that is if you take the SHMAx orientation from the -- and lay -- overlay it on the saltwater disposal well, that orientation direction points directly into our Avalon wells.

Q So the conclusion you've reached is demonstrated by the slide as well?

A In part. The other -- the other point that I want to make regarding this -- this area is that these wells produced roughly a 50 percent water cut over their -- over their well life up until we started to see interactions with the Wolfcamp completions. We were able to draw down.

We conducted a -- a pressure study in Sections 18 and 19. We were able to draw down bottomhole pressures to where we cut -- conducted those pressure surveys. We were seeing 500 psi to 800 psi on those surveys. And over the course of that -- that time when that well was actively injecting, we didn't see any indication of a water pressure change.

Q Let's take a look at the next aspect of your study when you looked at possible causes of faulting or the lineaments that begins on page 119 and then for subsequent slides on page 120. If you could explain to the Commission the work you did here and what the slide demonstrates.

A So now -- now we -- I've stepped back up to the previous example that I've shown where our Avalon wells do not interact with overlying and offset saltwater disposal in the Delaware Mountain Group. But we're -- we're focused now on the Delaware Mountain Group producers in relation to the Delaware Mountain Group injectors that are -- that are shown on this map on the right with the DMG producers being in green, DMG injectors being in blue.

Q This is again looking at those wells depicted on Exhibit 11 -- or 7, I mean?

A That is correct.

On the -- the well that has a callout labeled PLU 401H, I've got a pink dot that indicates where on a pressure -- I'm sorry -- production logging tool. Basically a production log that was run on that well. They observed 1,520 barrels of water coming in at one perforation cluster. That point on this well represents that inflow point.

We had a, as Tom mentioned, our geophysicist map out and look for potential faults, potential lineaments in our different development areas. And not being aware of this particular case study, I took the work that that geophysicist had done, and I integrated it into this example.

And on that map shown in green represent a potential lineament that was -- that was mapped out from seismic. And the location of that lineament trends between the -- the heavy metal well, the Bran well. And the projection of that extends through where you see that PLT inflow point on that 401H producer.

Q So you're talking about the green diagonal line that runs from the southwest to the northeast?

A That -- that's correct. And the significance of that with regard to the SHMax orientation that's shown with the double red arrow on the -- the bottom of the slide here is that a -- you know, any kind of fracture, lineament, fault, anything that's oriented parallel to the SHMax direction is going to be under an -- an opening mode or it's going to be in an orientation.

I would enhance or enable potential fluid migration through it versus an -- an orientation such as shown on the bottom of this slide. I guess there's two -- there's two little cartoons on the bottom of the slide.

The one on the left would represent an orientation of the lineament relative to the -- the SHMax and SHMin. That would give the opening mode. The one on the right shows that that lineament is now perpendicular to SHMax, so it would be under an orientation that would be preferentially closed or restricted fluid movement.

But having lineaments, faults, any kind of feature like that in the vicinity of the injection would be unfavorable. And this is a potential explanation as to why that -- that area has reserved the effects that were -- that were noted in here.

Q So is it fair to say that your conclusion as to the lineament is a possible pathway for the migration of fluids were observed?

A That's correct.

Q If you could turn to your next slide on page 121, this looks like a little bit deeper analysis of the same issue.

A That's correct.

So what I want to first call out is the locator map that's shown on the left side of this slide here. The blue box on that locator map represents generally the general area that we're

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looking at with this particular example. Looking at the -- the larger map in the center of the exhibit, there are several different colored lines here. And I want to describe what those are.

First are the green -- there's a green well location, a green well stick on the southern part or the -- the lower half of this map. That represents a well that was included in the case study. I believe that was Exhibit 8 as a well that had watered out or seen an increase in water production.

As part of the review of that case study, I did not observe any offset Wolfcamp A or Avalon or Bone Spring completions that occurred around the time of that well. Seeing increased water production, so we were able to exclude that as a potential driver.

But the -- on the right side of the map there are two triangles that represent the locations of two Delaware Mountain Group producer injectors that were completed in the Cherry Canyon and in the Brushy Canyon. Those were thought to be the potential driver to the -- the events that were observed and the vents being the increased water production in the -- in the Avalon well that's shown on the -- the map here.

I again integrated the work of our geophysics team. The blue lines on the map represent -- these are deep Woodford or deeper faults. And you'll notice that there's one that trends southwest/northeast across this map. And the -- the red lines indicate -- the red lines indicate a potential Delaware Mountain Group lineaments that the geophysicist had identified in that seismic volume.

And what I want to note here is two things. The first is that the DMG lineaments are roughly parallel to the deep faults that we -- that are interpreted in the area. And both of those are parallel or sub-parallel to the SHMax orientation here.

So again, this is a potential geologic control on why two saltwater disposal wells could potentially interact with the producing well that's over four miles away. So you know, looking at it from an interpretation standpoint, this would be an unfavorable location group to -- to put it in saltwater disposal wells.

Q Did you also take a step in regard to the lower containment for detecting influx?

A Yes.

Q And that begins on page 122, with a supplement slide on page 123 where you analyze the Bone Spring Lime thickness across the basin?

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A Yes. This -- this study went to evaluate the -- the strength or the ability of the Bone Spring Lime to prevent fracture growth from Avalon producers up through it. So one of the hypotheses that we identified early on is that these Avalon wells are potentially seeing water production -- production higher than -- than expected because they were breaching through the Bone Spring Lime.

So I've got a -- a map on the lower left side here, a map showing the Bone Spring Lime gross interval thickness. And this area covers the New Mexico portion of the Delaware Basin. Also on the slide is the Delaware Mountain Group risk area outline, but it's truncated at the Texas-New Mexico border, and that's shown in black.

There's a yellow star near the -- near the Texas-New Mexico border that represents the Madera Malcolm R ET 1 well. And the significance of this well is that in evaluating the Bone Spring Lime throughout this area, the -- although the gross thickness was roughly 30 feet thick, the net carbonate thickness within this well was -- was only representative of two beds that were approximately 8 feet thick. So this was a pessimistic case showing the thin or low side case for what the Bone Spring

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Lime thickness would be at the area.
Lastly, on the -- on the map shown on the left side, I've got the -- the starred locations in orange of the Papa Squirrel, the Severitas wells. And in white are callouts showing the -- the thickness of the Bone Spring Lime at 42 feet at the Papa Squirrel and 87 feet thick at -- at the Severitas location.
Q And what does it show on the right?
A On the right is the -- showing the log on the Madera Malcolm, the well that I had mentioned previously. And we're looking at -- in a -- in terms of the tracks, the first track is the gamma ray. Then you'll see the depth track with depth indicated in both TBD and TBD sub C.
The -- the next log frac is the resistivity, and there is ferocity along with the PE, photoelectric. And then lastly is just a lithology, -- lithology on the -- the right track.
Q If you could turn to your next slide on page 124 where you dug deeper with regard to the Bone Spring Lime being breached?
A Yes.
Q And what are you showing here?
A What's showing here was a -- a modeling exercise that had taken place to understand whether

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our baseline Avalon completions could potentially breach through the Bone Spring Lime at this location. So what was done is we took the base case completion with slurry volume per cluster basis and started out with 69,000 gallons per cluster.

We also studied sensitivities of 79,000 gallons per cluster and 91,000 gallons per cluster. And in doing that, we were looking at the potential that you weren't seeing the great cluster efficiency, meaning that not all the clusters were receiving fluid.

And in all three of those scenarios, we did not observe the Bone Spring Lime. Or let me, well, rephrase. We did not observe the -- the Avalon completions propagating up through the Bone Spring Lime. But we also undertook a study to understand what it would take.

So we -- we increased the -- the volumes for -- of it -- volume per cluster basis. And it took over 109,000 gallons per cluster in order to start to breach the 8-foot-thick Bone Spring Lime. But I want to emphasize that over our development area and over the -- the locations of our saltwater disposal wells that the Bone Spring Lime is significantly thicker than this.

And then one final note. You know, this is a model, so we want to calibrate it to field data. And as I mentioned previously, we were able to draw down our Avalon wells to less than a thousand psi bottomhole pressure, which suggests to us that we are not seeing influx of water from the overlying Delaware Mountain Group, meaning that those completions did not breach through the -- the Bone Spring Lime.

Q Can you turn to the next slide, which is just a summary of your conclusions? If you can go through them and express your opinions based on your study?

A Yes. To summarize, you know, looking at -- looking back at the case studies that were shared, I -- it's shown that water cut can have multiple drivers in unconventional wells. And really, we need data and we need to do more exhaustive analyses on these case studies to identify what the root cause is just because water cut alone in proximity to saltwater disposal is not a conclusion of interference.

We've seen consistently within our development area in South Lea County that we've had Wolfcamp completions interacting with Avalon wells. And often the response that we see those Avalon wells is -- the observation is similar to what was noted in

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Exhibit 8 from the OCD map in the previous study.

We have two cases of complete development areas where we're able to produce our Avalon wells in proximity to Delaware Mountain Group injection without seeing indications of communication.

When the SHMax orientation of features such as lineaments or faults is parallel to the -- when the strikes of the lineaments or fault are parallel to SHMax, those locations are -- that orientation's potentially enabling to fluid migration through them as opposed to when they're orthogonal to SHMax or perpendicular to it where the -- the lineament will be under enclosing mode.

Q And Chevron analyzed the areas around the two wells that are the subject of the pilot project to determine if they're lineaments?

A They have investigated it, and they have not any evidence within 2 miles of the locations.

Q And finally, what does the --

A In conclusion, the -- the Bone Spring Lime is -- is not being breached during Avalon completions. And the saltwater disposal wells are operating in a manner not to frac the reservoir. Whereas our Avalon completion is the intent of those was to break down the reservoir. So we were trying to stimulate frac of the -- the reservoir below them, and we were not breaching through the Bone Spring Lime.

Q In your opinion, will the Chevron wells that were subject to the pilot project negatively impact DMG existing or future projects in the area?

A No.

Q In your opinion will the Chevron wells negatively impact Avalon's wellspring production into the area?

A No.

Q In your opinion will the wells actively impact relevant rights of producers of Avalon or Bone Spring or DMG?

A No.

Q Were the exhibits we discussed today prepared by your or under your direction?

A Yes.

MR. DEBRINE: We would move the admission of Exhibits I believe it's 109 through 123.

MR. FUGE: Any objections?

MR. TREMAINE: Yes, Mr. Chair. Thank you.

MR. FUGE: Any objections?

Exhibits have been admitted.

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(Exhibits 109 through Exhibit 123 were marked for identification and admitted into evidence.)

MR. FUGE: Mr. Tremaine?

MR. TREMAINE: Making sure I understand the formulation of the questions.

EXAMINATION

BY MR. TREMAINE:

Q We're going back to slide 120. This is a clarifying question. What is the distance between the injection wells that you're referring to and the producing wells that were affected on the slide?

A Approximately two and a half miles.

Q And I want to make sure I'm understanding the summary of your presentation here. Is it Chevron's conclusion that the Wolfcamp wells are communicating with Avalon producing wells?

A They are. That is our conclusion, yes.

Q And can you speak to whether that communication is negatively affecting or damaging production in those Avalon wells?

A We have seen cases where it has -- where it has taken longer to recover in those wells. I can't speak to the -- the economic value of that.

Q And is my understanding also true that you cannot eliminate the Mesquite well SWD wells as the source of the interference for the wells?

A No, I'm not. I'm not suggesting that they're not.

Q In the area where the observed influence for the Wolfcamp completion was observed in the Avalon, were there any similar observations in the Bone Spring horizontal wells and the Avalon and Wolfcamp?

A I have not investigated that in that area.

MR. TREMAINE: No further questions.

MR. FUGE: Ms. Hardy, any questions?

MS. HARDY: I do have some questions. Thank you.

EXAMINATION

BY MS. HARDY:

Q Good afternoon. I've got a few questions for you, and I'm going to be jumping around a little bit here. If you can look at page 110 of the application file.

A Yes.

Q So it looks like this exhibit addresses or references six case studies; is that right?

A Yes.

Q And then the writeup within the subsequent exhibits I only see five.

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A Yeah.
Q Is there still -- what is happening with the sixth case study?
A Yeah. The sixth case is the orange circle that's shown on the -- near the state line on this map. And it's -- it represents the area where Chevron drilled eight Avalon wells, and since the beginning of those wells, they've seen high watercut and high pressure.
Across the state line -- difficult to explain. I guess across the state line and one section to the west, so approximately 1 mile to the southwest of that location, there is a saltwater disposal well that's completed in the -- in the Delaware Mountain Group.
We identified between that saltwater disposal well and our Avalon wells some potential localized faulting. And it's our -- it's our leading hypothesis that those wells are being influenced by saltwater disposal in that -- in that area. But that's the last case. I did not have an exhibit on it and did not discuss it.
Q And what's the current production status for the Avalon wells included in this case study?
A I don't know the current status of the

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wells.

Q You can -- what is the approximate vertical separation between the Wolfcamp and the Avalon shale?

A 3,000 feet.

Q And what do you think is the mechanism or the pathway that is allowing Wolfcamp fracs to communicate with Avalon?

A I don't know. But -- but the hypothesis is either existing potential -- existing open networks or the stimulation networks. But we -- we do not think that we are propagating the Wolfcamp fractures up all the way to the Avalon.

Q Is the frac being comprised or vertically through the pole rod section or is the communication occurring through natural fractures or faults?

A I think that's what I answered in the last question.

Q Those are that it's growing vertically through the?

A Oh, we don't -- we don't believe that it's growing vertically 3,000 feet.

Q You don't know. Have you checked the oil gravity to determine whether it's changed?

A We have not.

Q And let's see the next slide. Can you look

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at Slide 113? And there are three production rate versus time lapse on this page; correct?

A   Yes.

Q   And are these composite graphs for all of the Avalon well drilled in a path?

A   These are not. These -- these represent a sample of wells primarily taken from the -- the east side of the -- of the Salado Draw development area, so Sections 18 and 19.

Q   And what are the dates for the data that's shown on these graphs?

A   The dates indicate -- I don't have the -- the dates listed on here but these represent from the start of the well shown on the left side of the data all the way through just the years I've shown on here.

Q   So you don't have an idea or you don't know what the timeframes were?

A   Roughly 216 would -- would be the start of the plots, the times on here.

Q   And were any of these sections at least including the original production areas caused by DMG injections?

A   Can you rephrase the question?

Q   Yeah. Were any of these sections included in the original production areas that were influenced

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by DMG injection?

A Not sure I understand the question.

Q Let me ask this. Did the other Avalon pad show similar production performance or are there some that are showing water influx?

A Yes. The -- the paths that are shown on the -- the map on Exhibit 113 showed stable production. The -- the two sections that I've noted in that case study in sections 29 and 32 that are cropped off on this map are the wells that have showed increased influx from these early production wells.

Q So back on page 112, the exhibit indicates that Chevron observed significant production changes in Avalon wells overlying Wolfcamp A fracs; right?

A Overlying and your -- directly overlying and in proximity to the pad. So it did not have to be directly underlying the -- the Avalon wells impactor did not need to be directly overlying the Wolfcamp fracs. So even if there were a couple well spacings offset, we still would see the -- the influence of them.

Q And then on page 114, are you attributing the watering out of the Section 21 Avalon well to fracs that were completed approximately a half-mile away?

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A That -- that's the best bit of data we have, so we're looking at the fracs that are roughly a half-mile away, but we're also looking at the saltwater disposal well to that same distance and spacing where the Wolfcamp wells were, again, intentionally trying to break -- break down the rock, whereas the saltwater disposal well was -- was not. It was supposed to be injected under a frac gradient. So that's the conclusion that we lead to is that the Wolfcamp completions that are a -- a superior hypothesis.
Q And the Wolfcamp completions are several thousand feet deeper; correct?
A That's correct.
Q What typical half fracked length does Chevron target?
A I don't know.
Q Do you have any examples in this presentation where Chevron has performed targeted surveillance and Wolfcamp frac water traveled over a half-mile?
A Not in this presentation, no.
Q And has Chevron done that analysis other than in this presentation?
A Can you rephrase the question?

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Q Sure.
A Or restate that.
Q Sure. Has Chevron performed targeted surveillance of the Wolfcamp frac that has shown the Wolfcamp frac water has traveled over a half-mile?
A We have vertically. So we have seen indications -- it's not conclusive, but we have seen indications where a Wolfcamp to Avalon water mixing relationship is a valid solution to the observations that we have.
Q That's vertical?
A That's vertical.
Q But not horizontal?
A Not that I'm aware of. No.
Q Do you have the 3D seismic in this area?
A We do.
Q And have you been able to determine the location or trend of these fractions or faults that are allowing this fracture stimulation's appearance?
A Not in -- not in the vicinity of this area, no.
Q If you'll look at page 118 please. And this is a production rate versus time graph; correct?
A Yes.
Q And is this plot a single Avalon well?

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A This is, yes.
Q And where is the well located?
A Roughly in the center of Section 18.
Q And the data on the graph ends in late 2021; is that correct?
A That's correct.
Q Has there been any change in the production performance of this well since then?
A There has, yes.
Q And what has that shown?
A That's shown a Wolfcamp completion that was -- there was two paths of Wolfcamp wells that were completed on the west half of Sections 18 and 19. And this well has seen a response to that frac gradient interaction in both wells. And I believe that this well is actually one of the examples shown on another exhibit that has all this data.
Q And on the lower right side, the Mesa B SWD is highlighted; correct?
A Yes.
Q And is that a DMG SWD?
A It is.
Q And do you have any information about the history of that well?
A Other than what's located on the or

indicated on the slides, that's the -- the history that I have on it.

Q If you can please look at page 124. Actually, sorry, 121. What is the name of the well that is labeled 24/8/2011? Sort of the lower part of the --

A I -- I do not recall. And that -- that date represents the completion date for that well.

Q And do you know what zone that well is completed in?

A I believe it's Avalon.

Q What's the significance of these DMG lineaments that are shown on this exhibit?

A That it could -- that the orientation of those lineaments is parallel to the SHMax orientation and that they trend between the disposal wells and the -- the producer that's shown on the map.

Q Do they provide a vertical connection between different layers?

A We don't know.

Q On which path does Chevron believe the water moved between the SWDs and the producer?

A One hypothesis is since these lineaments are parallel to the deep basement faults that are shown here is that potential movement or even minor movement of those -- those features could reach through the Bone Spring Lime providing a conduit. We don't have data that -- to support those hypotheses.

Q Were the two DMG SWDs shown on this exhibit good disposal wells?

A I don't know the -- the rates that went into those wells.

Q Does Chevron believe there could be a correlation between the presence of faults and injectivity?

A I wouldn't be able to answer that. I don't have the background in that. It's not my area of expertise.

Q Let's look at page 124. And you indicated earlier in your testimony that your frac predictions were based on the models; is that correct?

A In part, yes. They were -- the modeling was a test. Yes.

Q And can you confirm that you won't be able to predict the shape of the actual fracs until the models are calibrated?

A The -- the frac model, the, like, details of the frac models, Cody Comiskey will be able to answer some of those.

Q Did Chevron run micro-seismic in this area?

A Yes.
Q Did that analysis agree with your simulation results?
A It did.
MS. HARDY: Those are all of my questions. Thank you.
MR. FUGE: Dr. Ampomah?
DR. AMPOMAH: Thank you, Chair. I do have some few questions.
So beyond the tunnel fracture model that you did, has there been any actual -- done to test some of these hypotheses?
MR. PARIZEK: We -- not to my knowledge.
DR. AMPOMAH: And is there any plans?
MR. PARIZEK: To -- there may be. And perhaps one of the other witnesses can discuss that. I'm not aware of what the entirety is of what 25 folks did, but I don't know the answer to that.
DR. AMPOMAH: Someone needs how do I put this? Based on the testimony it's more like some of them are still inconclusive.
MR. PARIZEK: In -- I think that's a great question and part of the basis of our pilot is to collect the data in order to really rule out and

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understand what the root causes are so we're not in a situation where we have multiple working hypotheses but no way to test them.

DR. AMPOMAH: So what about the trace test?

MR. PARIZEK: That's -- that's a key part of surveillance. However, it's difficult to convince an operator of a saltwater disposal well to run a tracer in their well when it may prove that that well connects to one of your producers. So having an operator operate the saltwater disposal and the producer, it helps to test those types of scenarios.

DR. AMPOMAH: And I know that's something that you want to do as part of the pilot program.

MR. PARIZEK: Yes. And we discussed by another witness, but that is part of our results, yes, is that.

DR. AMPOMAH: So the Avalon and the Wolfcamp, these are open and producing results; right?

MR. PARIZEK: That's correct.

DR. AMPOMAH: So where is the water coming from?

MR. PARIZEK: We -- we don't have a conclusive answer to that, where that water is coming from. We've seen -- well, what we have seen with the -- the surveillance that we have done is that we -- in the east half of the field, we have seen a valid mixing relationship between Wolfcamp water and Avalon water, meaning that multiple constituents show an increase in -- in enrichment. And in the west half of the field, we've seen a valid mixing relationship between frac water and Avalon water, suggesting that we were seeing migrated frac fluid up.

But again, we don't have water samples for all of the different benches, so we don't know whether that's potentially coming from another bench that we don't have to sample for. But we -- again, valid mixing relationships in those cases.

DR. AMPOMAH: So let me ask you this on your experience in this area. Why does it take induction rates for -- in this area?

MR. PARIZEK: The only example that I have knowledge of is the one that I shared on --

DR. AMPOMAH: [Unintelligible response]

MR. PARIZEK: Yes. I believe it -- that is --

DR. AMPOMAH: 118?

MR. PARIZEK: 118. That -- the typical rate for that well is between 2,000 and 4,000 barrels

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per day.

DR. AMPOMAH: So is it a general representation of the typical rates in this area?

MR. PARIZEK: In New Mexico, that's the example. Across the state line, approximately half a mile south of the state line, there is a well that has injected -- I want to say to the best of my knowledge over 10,000 barrels a day, potentially higher.

DR. AMPOMAH: So you talk about a geological feature like the lineament or send out potential communication, so have those been marked, you know, in this area, especially where you are, because of the pilot?

MR. PARIZEK: It has. The geophysicist has gone in investigation for DMG lineaments kind of mapping the way that they had done in the other examples that I have shown. And they have not identified any within 2 miles.

DR. AMPOMAH: And I just want to confirm. So you showed the thin thickness of the Bone Spring Lime. So I just want to confirm that in your area it's much thicker than in that 8?

MR. PARIZEK: That's correct. So that -- that map shown -- shown on Exhibit 123 or page 123, that well is located both outside of development area,

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the Salado Draw, and across the Texas state line. So it's outside of where we're going to be operating or potentially operating these two wells. At the locations of the wells noted it's 42 feet thick at Papa Squirrel and 87 feet thick at Severitas.

DR. AMPOMAH: Are there any extra fractures in this area that you're aware of?

MR. PARIZEK: That --

DR. AMPOMAH: Multiple fractures?

MR. PARIZEK: In the -- in the Bone Spring Lime?

DR. AMPOMAH: In the Bone Spring. Also the Brushy Canyon, and also the actual injection zones that you target?

MR. PARIZEK: Not that I'm aware of.

DR. AMPOMAH: So you don't believe -- could there be a possibility that there could be an existent fracture is causing some of the communications?

MR. PARIZEK: The -- the image logs that have been acquired over the area generally show -- and I'm speaking just in general in the Permian that the vast majority of fractures are -- are healed or sealed.

DR. AMPOMAH: So there's no need to get

a --

MR. PARIZEK: The -- I think it would be -- I don't -- I don't know the answer to that.

DR. AMPOMAH: -- Thank you.

MR. PARIZEK: Thank you.

MR. FUGE: Mr. Bloom?

MR. BLOOM: No questions. Ms. Hardy and Dr. Ampomah asked my questions there. Thank you.

MR. FUGE: I just had one, and it goes back to your testimony. 2016, if I was understanding it correctly, you referred to re-looking at some of the case studies there that the operator group came up with. And at the time they'd attributed to SWD. But in looking at it more closely, you know, it at least equally attributed in your testimony of kind of the Wolfcamp A completion.

Why wasn't some of that analysis done in 2016? Was the data not available? I'm just curious of the change in sort of the conclusions and the source.

MR. PARIZEK: I -- I wasn't part of the work group in 2016. But I will -- I would suspect that seeing Wolfcamp fractured interactions with Avalon was probably something that they weren't considering at that time. And having experienced that in our area, that's what prompted us to -- to revisit that.

And in fact, when I started out here in the Permian Basin, that was -- you know, that study was kind of a foundation that -- that I use in evaluating Solada Draw area in general. And when we started to see the -- the production changes in our Avalon wells around the time that we were completing the Wolfcamp fracs, we did test water and we were seeing different water chemistry that we had observed in the wells that we suspected to be watered out by the DMG.

So that suggested to us that that SWD to Avalon model wasn't an explanation for what we were observing and caused us to -- to investigate other -- other causes being built at Wolfcamp A.

MR. FUGE: No further questions.

MS. HARDY: Mr. Chair?

MR. FUGE: Yes, I'm sorry.

MS. HARDY: I apologize. Would it be possible for me to ask a couple more questions following Dr. Ampomah's questions?

MR. FUGE: Yeah, that's fine.

MS. HARDY: Thank you. I'll be quick.

//

EXAMINATION

BY MS. HARDY:

Q Can you confirm that for a Wolfcamp frac that you'd give with an Avalon producer, there would have to be a breach in the Bone Spring Lime?

A There would not.

Q There would not have to be a breach?

A So Avalon lies below the Bone Spring Lime as does the Wolfcamp, so it would not require a breach.

Q And I think you said this earlier, but can you confirm that you're not able to identify the fracture pathways that allowed the communication that's a result of the 3D seismic analysis?

A That's correct.

Q Based on Chevron's experience with stimulation appearance between Wolfcamp fracs and Avalon producers, have you seen an immediate response in the producer while stimulation operations are occurring?

A We have with pressure. We did see pressure response increase during the Wolfcamp completion.

Q Does Chevron shut in its Avalon producers while fracturing the live Wolfcamp horizontal wells?

A We do not.

Q Does Chevron surface commingle its Avalon

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Wolfcamp wells?

A I don't know.

Q What if your graphs shows water production versus gas-oil-ratio? That should be on slide 112. And is that a plot of the production from a pad or from an individual well?

A The -- which plot?

Q The water production versus gas-oil-ratio?

A That's an individual well.

Q Would Chevron consider this a tight curve for Wolfcamp frac to Avalon producer interference?

A Can you rephrase?

Q Sure. I'll ask it again. Would Chevron consider this plot a tight curve for Wolfcamp frac to Avalon producer interference?

A We -- we have not seen this type of response everywhere. Some of them were positive fracture-driven interactions. This represents a negative fracture-driven interaction. So there is not a -- a single response to those interactions. So no.

Q And is the entire production history of that well, that shelf on the --

A I don't recall.

MS. HARDY: That's all my questions. Thank you.

MR. FUGE: I think the witness is excused.

MR. DEBRINE: Yeah, no further questions. We'll reserve the opportunity to call on him for rebuttal.

MR. FUGE: Okay.

MR. DEBRINE: Chevron calls its next witness Bryce Taylor.

MR. FUGE: May I ask the court reporter to swear in the witness?

THE REPORTER: Please raise your right hand.

WHEREUPON,

BRYCE TAYLOR,

called as a witness and having been first duly sworn to tell the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

MR. FUGE: Thank you.

You may begin.

EXAMINATION

BY MR. DEBRINE:

Q Could you please state your name for the record?

A Yes, my name is Bryce Taylor.

Q Who do you work for, Mr. Taylor?

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A I work for Chevron.
Q How long have you worked for Chevron?
A I've worked for Chevron for approximately 11 years.
Q If you could give the commissioners a brief summary of your background and experience with Chevron as well as your educational experience?
A Yes, I'd be happy to. So I graduated in 2012 with a Bachelor's of Science degree in Mechanical Engineering, magna cum laude, from Brigham Young University. Subsequently hired on with Chevron. And while working full-time for Chevron, I also had the opportunity to work on a master's degree with the University of Southern California in petroleum engineering with emphasis in smart oilfield technologies.
I started off my career in Chevron working in -- in California in San Joaquin Valley assets as a reservoir engineer primarily focused on developing steam flood projects for steam floods. That's enhanced recovery. We'll inject steam instead of water to heat up the heavy oil.
I also did that for about two and a half years. And I stayed within California in those heavy oil assets but moved to a new team working as a

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production engineer for about two and a half years. Following that, I transferred out here to the Permian Basin as a reservoir engineer.

I get into our asset development groups who do drilling or do horizontal wells. My primary area of focus was in the Midland Basin where I was at -- had the opportunity to bring online approximately 200 unconventional wells across my tenure there. That lasted about four and a half years.

And then at the beginning of 2022, I moved into my current role, which is our water strategies senior petroleum engineering advisor for the entire Permian. And this role is primarily focused on long-term water -- produced water handling strategy. It's focused on their -- program and really the subsurface reservoir engineering related tasks and analyses as they relate to our produced -- produced water.

Q You said your responsibility includes the entire Permian, which obviously is part of New Mexico?

A That is correct.

Q Have you ever testified before the Oil Conservation Commission or Division?

A I have not.

Q Are you familiar with the applications that

Chevron has filed in these two cases?

A I am.

Q Are you familiar with the two wells that are the subject of Chevron's pilot project underlying these applications?

A Yes.

MR. DEBRINE: We would tender the witness as an expert in operations and engineering.

MR. FUGE: Accepted for those purposes.

BY MR. DEBRINE:

Q If you could briefly summarize, Mr. Taylor, the work that you did as a part of Chevron's pilot project that we're considering here today?

A Yeah, so be happy to. So my -- my testimony will cover several aspects of -- my first focus was on our -- looking at the -- the assessment of the remaining reserve potential in the Delaware Mountain Group talked about here today. In Tom Merrifield's analysis, there are some offset wells, and so I analyze those for their remaining potential.

I'm also going to speak today about -- a little bit more about containment. Jason just shared with us the -- the lower containment strength of that Bone Spring Lime. I'll be sharing an analysis of the upper containment, that upper seal of the -- of the

Lamar limestone.

I also have an assessment of some modeling work, how we identify analogs for the SWD wells, and applying those analogs to these -- these two wells in question, the Papa Squirrel and Severitas to modeled their -- the potential performance over their life, which will include what their radius of impact will be, what their total storage would be, and how the reservoir pressures could react over time as we inject water into these SWDs.

And finally, I'll give a brief overview of our -- our surface operations of our SWDs and the associated facilities.

MR. DEBRINE: For the benefit of the commissioners and the parties, the exhibits we're going to discuss begin on page 142.

BY MR. DEBRINE:

Q And the first substantive slide is on page 143. If you could just lay the background for that slide for the commissioners.

A Be happy to. So this slide is intended to orient everyone. You can see our Papa Squirrel SWD up there is Section 13 at the top of the -- the top of the map. As I mentioned already there early a -- two or three active DMG producers within a 2-mile radius of that well.

Those wells are located within the El Mar Field. The El Mar Field extends south across the state line actually into Texas. And as previously mentioned, there's no active DMG producers within the 2-mile radius of the Severitas well. So that this analysis, which I share with you here, is this exhibit and subsequent exhibits as focused on the DMG in the vicinity of the Papa Squirrel.

Q If you could turn to the next on page 144. And is this the beginning of the analysis of the three wells that were in this produce line?

A Yes, it is. Just to walk everyone through this analysis. So we have here in a plot on the right the production history of the Sahara Fed-Littlefield DR 1 well as you can see that the production history dates back to, you know, 1960s, 1970s. This is the entire production history of the well, so this includes its primary production and secondary recovery portions of its life.

The analysis -- the decline analysis that I conducted took into account approximately -- and each dot here -- sorry, on the chart. Green dot represents the oil production for a given month. And that's -- that oil production has been calculated in terms of

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barrels per day over that month.

The decline portion of the analysis covers an area or a timeframe of approximately five to ten years, as you can see indicated there by the straight line through the production points on the right to -- which is a sufficient amount of data to establish a long-term trend for this producer well. I did choose a cutoff rate.

As you can see there in the table on the left of one barrel per month. This is an extremely low -- low amount of production for any well just to really give this well the most benefit of the doubt to calculate its remaining potential.

As you can see the decline is -- is in my opinion extremely steep for a conventional producer at 33.67 percent per year. Extrapolating that decline out to that cutoff rate, it shows this well's potential item life would happen in June of 2026 with only 96 barrels of oil remaining to be recovered. Like to emphasize that most of the current production for this well is much less than one barrel a day. And in my opinion, this well is depleted.

Q Did you sit and want to analyze the other two wells?

A Yes, I did.

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Q And is that analysis on page 145 and 146?

A That is correct. A similar process was followed. Both of these wells, again, are producing much less than a barrel a day. One of the wells had that ringing assessment of only 11 barrels and there were only a few barrels remaining. And so again these wells appear to be depleted.

Q What conclusions did you draw with respect to the potential impact of the pilot project wells on the future production from these declining producers?

A My conclusion is that there will be no impacts to the trend -- the production trend that we're seeing since these wells --

Q Did you also conduct a decline analysis for the remaining reserves in the entire field?

A Yes, that's correct.

Q And I believe that begins on page 147?

A Yes, it does.

Q If you could just explain to the commissioners what you did and what you found out about this exhibit.

A Yes. So this is a very similar methodology. The only difference being this is rolling up and sending all of the wells together. You could see the decline there represented in the straight line at the right part of the plot. Over that defined period there have been a -- the well count of about 20 wells, which continued through 2022. Declining out those 20 wells also resulted in a 33.82 percent annual decline rate against a very high ceiling. Had the three individual wells examined.

The cutoff rate I chose for this analysis was 30 barrels a month for the entire field. That's a very small amount of -- a very small rate for a field. This is projecting with that cutoff rate of the field to potentially in the next year with only 1300 barrels of oil remaining.

I'd also like to apologize on the exhibit. We have a box there. We have kind of a blank there for "Most recent well drilled." The -- the year of the -- of those 20 wells, the youngest one was drilled in 1977. So these were old wells. You know, we kind of produced for a long life and are depleted.

Q And so what conclusions did you draw from your analysis with respect to the impact of the wells on the remaining reserves to the El Mar Fields?

A My conclusion is that there would be -- not be an impact due to the fact that the build -- it should be depleted.

Q So it's your analysis and conclusions as far as the Division's concerned that express with regard to potential impacts to the wells on either existing DMG production or future DMG production?

A Yes.

Q And what conclusions did you reach?

A Reached that there -- could you restate the question?

Q Yeah. With regard to their concerns with respect to those effect of the pilot wells on existing and future DMG productions in the area?

A My conclusion is that -- that due to the highly depleted nature of this field and the projected short life remaining that our wells would not have any impact on recoverable hydrocarbon.

Q Let's now turn to your analysis with regard to the upper containment zone, which begins on page 148 of the exhibits. The first substantive exhibit is on page 149, where you discuss a leak-off test. And could you explain to the commissioners what that consists of, the work you did, and the conclusions that you reached?

A Sure. I'd be happy to. So first it's, like, for those who are not familiar with the -- with an extended leak-out test just to walk us through it, the typical behavior of leak-off tests, what kind of data we -- we get. So you can see there there's a -- a couple of plots. The -- the central plot there on the -- on the slide is a representation of typical behavior as we conduct these tests.

So the first portion labeled by FIT there stands for formation integrity test. This is typically done to evaluate the strength and integrity of the new formation. And it's the first step after drilling a casing shoot.

Q And you're referring to the first graph on the left?

A That's correct. After the formation and access, the small amounts of fluid will be pumped into the formation over a period of time. As that fluid is pumped, the pressure is monitored. And the plot there, the blue line -- sorry -- and the green there down line at the bottom, that is the pump rate. The blue line is the pump pressure.

So that first portion gives us our formation integrity test. If we continue to pump oil and build up pressure, we enter a reason designated by LOT on that line, which is -- stands for leak-off test. So this is a test to determine that the -- the fracture pressure of the open formation. So again, it's conducted after drilling right below a new casing shoe typically.

We continue to pump there. We'll actually reach a point there at the apex of the graph, which is the formation breakdown pressure. Again, just a regular leak-off test is when that formation first starts to take fluid. That formation breakdown pressure is when it is completely compromised. You will then see a relaxation in the pressure.

Q And that's shown there with the stars?

A That is correct. You'll see that relax of that pressure. If you continue the test beyond that, continue pumping, that's when you enter into the range of the extended leak-off test or XLOT. And this enables us to identify fracture closure -- closure pressure, which is commonly referred to as fracture parting pressure in a lot of the documentation that we -- that we typically see in the industry.

Q Well, when did you conduct this test?

A Yes, I'll get to that in just a second.

What will happen with the XLOT is eventually you stop the pump rate and watch the pressure decay. There are some -- some transforms that we can do with the pressure data and time in order to find some trends. Not going to go into detail on that specific analysis today, as this is just a summary of the -- of the test.

But you will be able to find a point, which is indicative of the fracture closure pressure. And that's how we get that datapoint. And as to your question, we conducted a test on -- in October of 2022 on a well in Texas. It'd be 174WA. That is in our Delaware Ranch Field, which is if you think where the Severitas location is, it's approximately 25 to 30 miles southwest that -- over in Texas.

The reason why we decided on a location is that the DMG gets a lot shallower as you go to the west. The -- the overburden thins, and due to how much shallower the Lamar is at this point, less of an overburden, this was considered a good spot test in a conservative nature what the strength of that, that Lamar is.

We expected it to be much stronger as it gets deeper, and the overburden grows to the east as is where our Severitas and Papa Squirrel wells were located. So I mean, this kind of represents a more conservative estimate of the strength of that -- of the Lamar. You can see there that graph -- graph in the top right of the chart or the slide, this is the behavior of the actual XLOT test that we noted as well. And you can see we saw the leak-off point, but we never actually reached formation breakdown pressure.

The -- the formation was so strong that our pump capacity was reached in the pump tricks before we were able to actually see the -- the formation breakdown. That's a very good -- good information that we have a very, very strong pump at Castile. The surface pressure at that point was 2200 psi.

As you will recall from our request for pressure for the Severitas and the Papa Squirrel, we're -- we're talking, you know, 460 psi for the Severitas and then the 925 psi for the Papa Squirrel. So much lower than this 2200 psi.

Q Let's take a look at your next exhibit on page 150.

A Yes.

Q There's a lot of data on here, but if you could just briefly summarize it for the Commission?

A Yes. Yes, I would be happy to. So this is the summary of our XLOT test. We actually did three cycles of the tests on the Lamar and just collecting more data there. You can see here a lot of the details. Like our casing shoe depth was just at 1584 feet, so very shallow.

If I can -- sorry. If I can point you to the red outlined boxes and the table there out of that second one up from the bottom on the leftmost is, like, 1.22. That was the minimum stress gradient or the fracture closure pressure identified in Cycle 1 was 1.22 psi.

But Cycle 2, we would expect it to be weaker since we've already fractured the rock in the first cycle. It dropped down to 1.15. And then the Cycle 3, a little bit hard to interpret, but it was between 1.1 and 1.14. So we figured that's our -- that fracture parting pressure or that fracture closure stress.

The other point that is interesting is that we look at the -- at the other red box there, the leak-out pressure and pounds per gallon. And actually all it is, it's not actually in the table in psi per foot.

But on the -- the third bullet down on that right side, I -- I calculated when that ppg would be and psi per clip, to identify that leak-off point, which again is that point at which the -- the formation first starts to become compromised and starts taking fluid. And that wasn't until 1.5 to 1.53 psi per foot.

Q You're referring to the second bullet on the

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right?

A I believe it's third bullet on the -- on the right. Yep.

So if we take that -- yeah. So again, just another -- another datapoint to share how strong this formation is. Now, if we look at actual injection operation in -- in the state of New Mexico -- and as we know the initial estimate for maximum surface injection pressure is determined by taking the top of our injection interval. We multiply that by .2 psi per foot.

So that gives us the maximum surface pressure. We -- in order to understand what the bottomhole pressure will be for the well, we need to add the weight of the fluid and there's -- taking out effects for a minute. If we -- to be a typical injection water is roughly .5 psi per foot. And just from its weight, you know, it can be a little bit lower than that, a little bit higher.

But .5's a good -- good estimate. We take that .5 and add it to the .2, you're looking at your -- at the bottom of the well, approximately .7 psi per foot. And again, leak-off -- leak-off pressure for the Lamar is 1.5 psi per foot.

And then if we even look at the minimum

stress gradient, it's at the -- yeah, that 1.1 to 1.2 range, that parting pressure, again much higher. So that -- I'll just direct you to the -- kind of the summary box there on the bottom of the slide. This gives us a safety factor of 1.57 to 1.74 depending on if you're looking at the -- that 1.1 psi per foot for minimum stress gradient or one of the higher numbers. So all this to say that seal is very confident and we don't see any chance of really breaking it down during normal injection operations.

Q And again, it's much thicker in the areas of the two wells of the pilot project than the wells where you conducted the leak-off test?

A The Lamar itself, I'm not sure. I do know that the -- relatively it's going to be the same. But it's similar in thickness. The -- the question is the overburden, since we're much deeper, there's just more rock between the -- the Lamar and the surface.

And as Tom Merrifield pointed out in his testimony earlier, we did see our subject matter experts when they were analyzing this data did see additional -- a lot of this additional strength. And part of the Lamar was due to that Castile and the overburdened formations that were right there. So do expect it to be stronger to where we have our -- our two wells pumped.

Q We can turn now to the injection modeling that you did with respect to the two wells?

A Yes.

Q It begins on page 151. And let's turn to page 152, which is the locator data.

A Yes. So in this next section, I'm going to talk a little bit about rate transient analysis, what that is, and how we used it for our -- to figure out our analogs to then be able to stimulate the -- the performance of the Severitas and Papa Squirrel.

Though just to orient everyone, you can see on the map the Severitas well in green -- with the green star and Papa Squirrel with the blue star. And then there's these markers across the state line down to Texas. Those represent wells that were -- were used as our analogs, so those are all DMG SWD wells.

The reason why we were able to use these wells is because they publicly reported data on these wells on daily rates and daily pressures, which for RTA analysis is what we would like to see.

Q And just for laymen's terms, what is rate transient analysis?

A Rate transient analysis. So I will actually get to -- get into -- it's a good segue to the next

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slide. So what rate transient analysis is, is it lets us take the rate data and pressure data from either producer or injector -- in this case an injector -- and transform that data through derivatives, pressure differences, different ways to look at time.

And we can plot out those -- those transforms. And then we know that there's several analytical solutions, the models of reservoirs that will match the characteristics we see in that data. And so what we're able to do is kind of pick and choose these different reservoir models, match it to the data, and -- and then finetune different parameters such as our permeability, porosity, thickness, the injection radius, or what -- how big your -- big your reservoir is.

You can find it -- there's other parameters we can -- we can tune. But we can do all of that and essentially match the data to one of those reservoir models. And that gives us a -- a good approximation of what the reservoir looks like that the well is injecting into.

Q And the parameters you described, are those all shown on page 153?

A Yeah, these are some of the parameters, the ones we -- we thought were most useful for the subsequent steps of modeling. So again, with -- with the rate transient analysis, the -- you know, we mentioned earlier that, you know, permeability in the hearing was a -- was a question. How can we understand permeability?

So one way to major that is -- is through this rate transient analysis, which you get permeability goes directly into how much our wells will improve from a rate standpoint. The other really important thing when it comes to SWDs is how far do they inject.

Most of these injectors can be described by a relatively simple model. It is a -- essentially, a radial flow model with the -- steady state radial flow model. An easy way to think about that is I have got a cylinder with my well right at the center of the cylinder, and that cylinder represents my reservoir so the -- it represents the storage tank.

And so at the edges of the cylinder and the model, we have what is called a new flow boundary. Just a point where the -- really, the end of the influence of the -- the specific injector. We'll see pressure influence beyond that or the -- the long-term fluid influence beyond that, you know, flow boundary.

So we're trying to determine the -- how the

R2SWD wells will impact the surrounding reservoir, how far out will the injection go. This was a way to understand statistically what SWDs typically do. And you can see there in the table kind of the summary of those calculated values where kind of the median -- the calculated value for injection radius was 8,979 feet. Permeability was the -- in that median value was about 13 millidarcy.

And then the other thing to -- to point out is the cumulative injection number. So the other thing rate transient analysis lets us do is forecast the well out beyond his production history. So once we've got -- or injection history in this case. So once we have a good match on the -- for our model. We're able to match that -- those actual rate and pressure datas with the -- with the model.

We can then use that -- use the program to -- the computer program we're using to do this. It's called Kappa, and it's got multiple different software suites. So let -- let's us do the rate transient analysis and other things. Anyway the -- the software will then allow us to forecast out the -- just what the performance at this well or these injectors will be like over a number of years.

And so we can essentially forecast that out to the end of life by setting the maximum allowed surface injection pressure, which is our constraint, and then letting the model run and the driver behind the decline that we see in the injectors is the reservoir pressure within that no-flow boundary increasing.

Eventually, that reservoir pressure will increase such that it equalizes with the bottomhole injection pressure with the well, and at that point more fluid can go into the reservoir. And so that -- that tells us what the total storage is of the DMG injector.

Q Let's now take a look at the actual modeling you did for the two wells pilot project.

A Yes.

Q The first one begins on page 154 for the Severitas well.

A Yes.

Q Would you just tell the commissioners what this shows and the data and the conclusions you reached?

A Yes, I will.

So the Severitas the -- is the headlining. And the headline for this -- for this well is the cumulative storage at this location is 28.8 million barrels of water over the life of the well. The -- and that cumulative storage, as we'll see in a second, it's really dependent on depth. And that's mostly because the depth is directly tied to the maximum allowable surface injection pressure.

So this well in particular, again, at that location, you know, just under 29 million barrels, I have here in the chart at the top right the outputs of the great profiles for this well with the -- the three different scenarios reflecting different permeabilities.

So we set the model with the parameters of the injection into the Bell and the Cherry with that 8,979-foot boundary radius, which correlates to about 1.7 miles. And with the corresponding porosity values that we -- we got from our geologic assessments of the area and then we applied the different permeability here to understand what are low, mid, and high cases.

And you could see those by the blue line, orange line, and gray line for this location. And so we have a, you know, expected range of anywhere between just under 4,000 barrels of water per day to just over 12,000 barrels of water per day for this well.

Q Did you also look at the effect of the injection reservoir over time?

A Yes, we did.

Q If you could turn to page 155.

A So this assessment is to show how that reservoir pressure within that no-flow boundary radius will increase over time. So as you can see there, on the plot and the Y axis, we have pressure that is -- represents the reservoir pressure taken at the top of the Bell Canyon, which would be the top of our injection interval, and then the X axis is the depth of the investigation. So like depending on spatially how far away I am from that injector what -- what I would expect the reservoir pressure to be.

And you can see that travels out to just below that 9,000 foot mark. So we end up using that same kind of median injection radius there. Each line represents a different amount of cumulative injection. And this model was based on darcy radial flow, -- radial flow.

Q And so the bottom line conclusion that you reached?

A Yes. So you can see there in the gray box after years there even the colors are corresponding to that low, mid, and high permeability cases that we looked at on the previous charts. Just speaking to the mid-case, which was that 13 millidarcy. You can see how long it would take for this swell to pressure up as a -- as this time goes by.

And so to get to that, that orange line there, which represents 200 billion barrels injected and roughly 300 psi increase from starting conditions would take 13 years.

So we're looking at over a decade before that, even a 300-psi increase would be realized in the reservoir. But that is -- that's not very fast. A lot of that's due to how -- how large the injection radius as at that 1.7 mile approximate radius.

Q Let's turn to your analysis of the Papa Squirrel well, which begins on page 156.

A Yes. So for the Papa Squirrel well, I mentioned earlier, this well is much deeper. You get a higher surface pressure, and in turn you get more cumulative storage.

We've -- we've kept the same -- same size reservoir, but you know, 8,979-foot boundary radius using the thicknesses of the Bell and Cherry and the corresponding porosities at this location. And then we simulated the injection rates for the low and high cases again, represented by the blue, orange, and gray curves there on that run plot there at the top right.

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Should have data correspond to 6 millidarcy, 13 millidarcy, or 30 millidarcy.

You can see the -- the predicted rates for this well vary between as low as 9,000 barrels of water per day to just about 20,000 barrels of water per day. And yes, the storage here again is just under 73 million barrels.

Q And if you see the same slow increase of pressure of the reservoir on time?

A Yes, that -- yes, it -- this well for a similar time period, in this case to inject 40 million barrels, get sent to that green line. And that represents about 450 psi increase. It took about 11 years. You know, it's just a little bit higher than the increase of 300 psi in the previous well.

And that's just due to higher rates, higher pressure, better rock quality due to increased thickness and other items that we've talked about already so far, so that rate -- pressure increase are similar timeframe is slightly higher. That's still relatively slow, only 450 psi over a decade.

Q The next subject of your testimony is labeled "Surface Systems."

A Yes.

Q And what do you mean by that? What did you look into?

A   Yeah, so I -- this is to share with the Commission and others present, just our -- how we typically operate our SWDs. This is related to our facilities and operations teams, and I'm relaying that to you. So typically, how we -- and Davis reflects that we operate shallow SWDs today out over Texas as well as the deep SWDs that we still have here in New Mexico and the -- the ones we saw over in Texas.

So typically, we have the central facility or SWD facilities which process the water and, well, talk about it. It's -- they also have filtered well and clean it up at skim well off of the water to send back for processing.

And then eventually the water is sent to H pumps or horizontal pumps, positive displacement pumps where it is pushing high pressure flow lines, which carry it to a network of SWD wells. Each well is controlled by locally by a production log controller or PLC at the well site, they have two chokes which can be sit to determine the max pressures and the -- or the rates that we would like to send to each individual well.

The flow rates are constantly monitored onsite by flow meters. We typically set -- put our

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injection pressure set point at about 25 psid before the permit maximum allowable or whatever set point we -- we choose. You know, we won't go up. We won't set it above the permit, but we have it at a lower set point for whatever reason that would have a similar target.

We have automated processes and alarms so that if the pressure increases above that permit for more than 30 seconds above the set point, yeah, a call is sent out to an operator. The operators that we have are -- are based on our -- our field locations and our -- yeah, our offices out onsite in the fields. We also have a removed monitoring group in -- in our Midland, Texas office, which monitors all of this data in real time for all of our operations.

So anyway the -- that alarm triggers and no one goes to visit the well within a half-hour, it will automatically shut in until someone can get out there and fix the issue. We also have a high-case scenario where pressure goes greater than 110 percent pressure for more than 30 seconds, the mobile off will shut in.

Q I think you mentioned data monitoring. If you turn to example on the page 130, is that example the data that you collect?

A Yeah, this is -- yeah, so this is a -- just

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an example for the types of data that we look at in real time. The shortlist data real time by our SCADA units that -- and all of it's pulled into our integrated operations center.

And so it -- data such as flow rate, injection pressure, downhole pressures, control valve pressures, casing pressure, temperatures, et cetera, are a lot more monitoring that I'm not sure here that we have at the actual facilities and the tanks favor themselves. But I just wanted to give everyone a sense of the -- the type of real time data collection that we -- we have in place already, we plan to implement on this new SWDs.

THE REPORTER: And by SCADA, what is that acronym?

MR. TAYLOR: Sorry. I do not know. I cannot remember off the top of my head.

MR. DEBRINE: I don't remember either.

BY MR. DEBRINE:

Q If you could turn to the next line, the page 161 where it says, "Discusses the handling of solids to improve the quality of the alarms."

A Yes. So that makes sure that everything -- in order to improve the longevity of our SWDs we recognize that the water we send down them has to be as clean as possible. That would mean they don't want to frac and solids are -- are particles that are so big it will plug up the -- either the perforations or once it gets out into the reservoir, the pour space.

And so to do that, we have a couple filtration devices, which will collect one or two particles. I think the current design is a hundred mesh filters. It's always being looked at to be optimized. It's the -- the toilets are flushed to the point of tank where the solids settle out. On the comb bottom foots, it's constantly monitored.

And then once it -- now solid that -- solids that accumulate reach a certain level. I -- work will be sent to operators. And then they can operate a truck to come pull the solids off the -- off that tank.

Which the solids are then removed to solid waste facilities much like we could remove drill cuttings or other -- other items left over from oil and gas operations. And then all of the water in that flush tank after it's rattled back to the charge cost of the inject -- went through the cycle again.

Q And if I'm on page 162, is that a summary of the conclusions that you reached as a result of your study?

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A Yes.

Q If you could just walk through this with the Commission?

A Yes, I will.

So first and foremost, our -- our proposed SWD wells are in the best interests of conservation, prevention of waste, and will not impair our correlative rights. The nearest DMG producers -- and fields whose injectors are depleted, that Lamar limestone is a very confident seal of the DMG which to provide their containment looking for production numbers that are associated with the SWD operations do not come anywhere close to that fracture closures, leak-off pressures, or breakdown pressures of Lamar.

Our DMG SWD analogs show that SWDs at the DMG tend to influence the reservoir after about 1.7 miles, and reservoir pressure in that radius is expected to increase slowly during the -- the operation of our wells.

And -- and here you can see the great summarized with Severitas and Papa Squirrel. Severitas anywhere between 4 and 12,000 barrels of water per day and 29 million barrels in total storage, while Papa Squirrel, a deeper, better location anywhere between about 9,000 to 20,000 barrels of water per day and 73 million barrels of storage.

Chevron does -- our standard operations for SWDs feature active monitoring and control logic to ensure safe operations, with real-time -- and real-time data collection. And finally, our -- our SWD facilities are fitted with filtration systems to improve injected water quality, utility, and life of these SWDs with all solids removed to appropriate solid waste facilities.

Q Were the exhibits we discussed on page 142 to 162 prepared by you or under your supervision?

A Yes.

MR. DEBRINE: Moving to the admission of Exhibits 142 to 162.

MR. FUGE: Any objection?

They're admitted.

(Exhibit 142 through Exhibit 162 were marked for identification and admitted into evidence.)

MR. DEBRINE: And we'll pass the witness for question.

MR. FUGE: Mr. Tremaine, do you have cross?

MR. TREMAINE: I do have a couple questions, Mr. Chair.

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EXAMINATION

BY MR. TREMAINE:

Q Looking at the slide 143, map slide of -- producer producing wells in the El Mar Oil Field?

A Yes.

Q Can you provide any more detail as to which part or zone out the DMG those wells are completed in?

A I do not recall. That topic -- I can defer that to -- to Tom Merrifield.

Q That's what we need.

MR. FUGE: We can do it now. Mr. Merrifield. Ask that question now and bring it back.

MR. TREMAINE: Since he's already sworn in, I think we'd be comfortable having him just answer the question.

MR. BLOOM: No objection.

MR. FUGE: Yeah, no objection.

MR. TREMAINE: Thank you.

BY MR. TREMAINE:

Q And just a clarification here. It sounds like from your exhibits and your testimony that there is that proposed wells, you conceive a 1.7-mile injection radius?

A Yes.

Q So the total area of impact would be approximately 3.4 miles across?
A Yes.
Q Remind us what the radius was that Chevron enjoys for its area of --
A So I know -- I know before our -- we used that half-mile radius as dictated in the -- the rules for notifications and then the -- internally, one of the reasons why you kept seeing 2 miles kind of up there as we were looking for offset producers was partially because of this -- obtain analysis just to give us a little bit extra of a buffer and just say that they do not recall the exact radius for the -- for the AOR.
Q Thank you. And then I want to -- one more question. I want to look at slide 159. Can you explain the reason for the 30-minute delay for that shutoff?
A That's -- yeah, that's just something to call out. Standard practice, I guess. I'm intimately familiar with the exact reason why my -- part of the reason, though, is to give the operator time to physically travel to the well site, which are -- which are kind of the -- somebody has to drive out there.
I -- again, I'm not -- I don't know the

reason behind why 30 minutes was the number agreed upon, if there would be a -- you know, a longer or shorter duration that would be more optimal. It's just our current -- current control logic.

Q Are you aware, according to the current proposal, how much volume could be pumped during that period?

A Could be calculated. It would depend on the -- the time, the -- at what stage of the well's life we're in where that could happen. They did -- they do -- like to -- their rates looked -- I declined them I'd say more rapidly than we would like, so I -- I don't have that number off the top of my head, but it could calculated from the -- the plots shown in the exhibits.

MR. TREMAINE: Thank you. No further questions. Thank you.

MR. FUGE: Ms. Hardy, do you have any questions for this witness?

MS. HARDY: I have a couple of questions.

EXAMINATION

BY MS. HARDY:

Q Hello. I just have a few questions for you.

If you can look at page 152. That's the

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"Location of Wells with Sufficient Data for Rate Transient Analysis"; right?
A Yes.
Q Can you confirm that Chevron's drilled DMG SWD wells on its Texas acreage?
A Yes, we have.
Q And did Chevron perform similar testing as that proposed in Mexico pilot in those wells?
A As far as rate transient analysis is concerned?
Q Right. Who's out there testing and monitoring this?
A So yes. The -- one of the reasons why we didn't include our -- our own data in these areas is that, you know, number one, due to the timing of this analysis also our wells are relatively new and only been put online in the last few months. And you -- we typically like to see several months of -- of continuous data before we can properly analyze a well with rate transient analysis.
The -- really the shortest amount of time I've seen is approximately four months or six months to read is a lot better. It also depends on how high quality your data is. Downhole pressure will just make the process that much easier when you have

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downhole pressure gauges and are Severitas and Papa Squirrel well.

We do have Chevron wells, but then just you had -- had some other operational issues that have prevented them from operating that consistently that first available to conduct that type of analysis. So these wells that we -- we used for our analog study again have the -- the sufficient history and the data and the -- the daily orthographs to conduct your transit analysis.

The shorter enrollment you have for your datapoints, the better for this analysis. Daily is -- we would like to go more than daily. So there are a lot of wells out there that report monthly data. However, it takes four to five months to even see the initial cycle of monthly data. You'd only have four to five datapoints. You wouldn't be able to interpret --

Q And so in Texas DMG SWDs, do you know what intervals are being tested?

A Yes. All of these are either -- they're all DMG shallow wells that we looked at. Don't recall if it's -- some of these might have Brushy Canyon targeted at or just -- just Bell and Cherry. These wells in particular fall within some of the Texas seismic review areas, which is why they're required to report daily rate submissions.

Q And do you know what the bottomhole fracture gradient in those wells has been?

A So there's a range. Part of the reason why we conduct separate tests is to determine that individual wells and say for our own wells we've seen anywhere from, you know, .62, .65 psi per foot up to .72 psi per foot. So that really does -- does vary. I mean, those numbers sound like they're close, but when the -- you're talking about the injection rates that there can be a -- you know, a fairly -- have fairly wide implications there.

And so again, that's a reason why we -- we have -- agree with the OCD's direction to conduct a separate test, find that fracture gradient, and then face our maximum pressures alphabetically.

Q And I think you testified earlier the average fluid gradient is .5 psi per foot?

A Yes.

Q And then if you add New Mexico service pressure and gradient on .2 psis but you'd see a bottle operating at .7.

A Yeah, and that remember is at the highest possible case where you forced to not water down against a -- a close pipe essentially. And -- and since you actually do have flow that will go out into the reservoir that will actually be the maximum pressure that's slightly lower than that, but it's a good rule of thumb for -- yeah, I have a whole lot of some safety factors just to -- just to see how close we're coming to -- to fracture pressures.

Q And if the bottomhole gradient was .7 psi, is it correct that then you'd be fracturing the DMG?

A Yes, but according to the rules that, yeah, we agreed with from the OCD, once we found that -- that fracture gradient, I think there's a, like, 90 percent safety factor that's applied to that. And so our max surface pressure would be in -- you know, that safety factor's set the load for that fracture.

MS. HARDY: Those are all of my questions. Thank you.

MR. FUGE: Dr. Ampomah?

DR. AMPOMAH: Let's start with slide 147. So you've presented about why you believe that Chevron believes that the DMG group is not ready for that.

MR. TAYLOR: Yeah.

DR. AMPOMAH: So what is the typical residual saturation for these areas that you analyzed?

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MR. TAYLOR: I do not know. But that is not -- not something that we had the current log especially if you want your current log data to be able to analyze it.

DR. AMPOMAH: Yeah. So you're saying that we're meeting in place right now is a 1.3?

MR. TAYLOR: Yes.

DR. AMPOMAH: So if I want to believe that we cannot produce any amount of -- I want to know the vertical saturation right there. So you talked about this going through primary, secondary. So were there water injections earlier?

MR. TAYLOR: Yes, the -- in the 80s, as I recall, there was a water flood. An injection was implemented at the -- at the El Mar Field.

DR. AMPOMAH: Do you know the injectivity of those injection wells?

MR. TAYLOR: I do not. I do not.

DR. AMPOMAH: And you did not analyze that as part of your analysis?

MR. TAYLOR: No. Most of the wells, we looked at from an injector standpoint. And we wanted to look at modern day SWD wells. Typically, we would look at these enhanced well -- recovery wells. They inject at much smaller intervals. They're just targeting, you know, tens of feet. We want to target, you know, thousands of feet for injection.

We also noticed that the rates that they see it and the maximum rates on their permits and then at least on the Texas side and some of the pressure that we've seen in New Mexico or -- or very low so you're looking at, you know, typical injection rates, about a thousand barrels a day.

The SWDs have their purposes to put away a lot more water, to enable the oil productions in the fields, and to much steadier intervals at much higher rates for an SWD to be successful. So yeah, really, the wells I presented for the -- from the RGA standpoint, were the best analogs we can find in the vicinity of modern day DMG SWD wells.

DR. AMPOMAH: So now Chevron owns these wells that were analyzed?

MR. TAYLOR: No.

DR. AMPOMAH: And then the companies that own these wells didn't already -- did you support the analysis that you did?

MR. TAYLOR: I am not aware of any feedback from those companies. But we -- we based this of, like, data.

DR. AMPOMAH: Let's go to slide number

or page number 150. So I do have quite a number of questions on this page. So the first one is what is a stress gradient here?

MR. TAYLOR: Can you clarify?

DR. AMPOMAH: Yeah. Where is the stress gradient in this area?

MR. TAYLOR: You mean in terms of the SHMax?

DR. AMPOMAH: Yeah. But depending on whether the SHMax lays on the SV, then there --

MR. TAYLOR: So the -- the stress orientation is to put -- and I don't have my slides, but in the other exhibits we've seen today, including the ones that Jason shared, that's -- that's a stress orientation of the southwest for these.

DR. AMPOMAH: No, I mean, I just want a clear answer to what is the force of G in this area?

MR. TAYLOR: I -- I'm not the right person to answer that question then.

DR. AMPOMAH: Can someone respond to that?

MS. BENNETT: Mr. Comiskey can. Do you want him to give input now?

DR. AMPOMAH: Yeah. It's very important to all my other questions.

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MR. FUGE: You can just walk up, just get a little closer to the mic.

MR. COMISKEY: So if I believe I understood the question correctly, it was what is --

DR. AMPOMAH: Based on the Anderson theory.

MR. COMISKEY: Yeah. So and this is a normal faulting environment. So what this means with the vertical stress is greater than the horizontal stretch beginning in the minimal stress. So it's a -- it's a normal faulting environment.

That's mostly dominated in the -- in the Delaware Basin. It just needs to move into the Midland Basin to get a little bit more of a -- of a strike slip type in my -- slide my testimony it will force that -- that theory as well.

DR. AMPOMAH: Yeah. So if it's a normal routine, you do have SV all the same as your minimum stress. So now I don't understand.

MR. COMISKEY: So we've seen in -- in this area that minimum horizontal stress is somewhere around .65 and .75 psi, which puts the magic number horizontal stress around .9 and the vertical stress around 1. And then -- formal breakouts -- also looked at focal mechanism aversion for a moment just for short breaks that tied that into the -- roughly values. And they quarterly head back to -- as well.

DR. AMPOMAH: So let's say would that be more like related to a normal reservoir? Because I didn't know what that meant. Lamar is more like a -- right. So I just want to understand how the minimum stress point is about 1.2 psi before, and then the -- too.

MR. TAYLOR: Yeah. I think part of that might just come from mislabeling minimum stress here. This is not to communicate that the minimum stress is that work well. I guess it -- it's really the minimum fracture closure pressure that we got from the XLOT.

DR. AMPOMAH: So I don't take that as a minimum result of stress?

MR. COMISKEY: Correct. Correct. That's -- that's the closure stress gradient, not -- not the actual instance you stress test for.

DR. AMPOMAH: So do we need to do it to make any adjustments to this? Because it's confusing to me actually.

MR. TAYLOR: That -- you're requesting, I guess, an update to the exhibit here?

DR. AMPOMAH: Yeah. Because, like,

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let's say if someone takes your data then use that in future, you don't see that little permission more or less, agree to a minimum result of stress. Let's say 1.32 psi compared to SV of 1.2 psi. That would be -- I don't want to agree to that.

MR. TAYLOR: Understood that. Date the -- update the label?

MS. BENNETT: Yeah, but you can do that -- update the label. And I also need to fix a typo in the slide about the last date drilled over DMG so we can submit those two together.

DR. AMPOMAH: Okay. Thank you.

So on slide number or page number 152, so I just want to clarify that the blue locations are where you have the wells that you use for the analysis?

MR. TAYLOR: Yes. Those are the locations of the analog wells.

DR. AMPOMAH: Okay. The analog wells. And all of these are in Texas?

MR. TAYLOR: Correct.

DR. AMPOMAH: So my first question is what is the distance between the closest one to the Papa Squirrel well?

MR. TAYLOR: Yeah, that's a good

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question. There's not a scale on this map, so I can't.

DR. AMPOMAH: I do live very close to the --

MR. TAYLOR: Severitas?

DR. AMPOMAH: Yeah. I don't want to be that close. But near Papa Squirrel. And I do see also that he brings the analysis to propose 20,000 daily rate and a 50,000 daily rate. These are analogous, each well analysis; right?

MR. TAYLOR: Yeah. So coming back to what was submitted in the C108 versus the analogs here. So the C108 analysis was done prior to having this dataset completed. So we actually used it, no one else's software and then a -- a much smaller subset of -- of the analog SWDs to figure out what a -- the productivity index or injectivity index would be for the reservoir, where you applied that to the -- the well bore and depth conditions in both the Severitas and Papa Squirrel to then calculate what the rate would be.

And that was what was submitted into the C108. You notice that that agreed quite well with the Papa Squirrel range the Severitas, the analog well that we used was a little bit optimistic in that case and smaller subset at the time. So it had -- and our -- and our filings are requested some rates that were a little bit on the high side of the estimated range from the numerical model. It was based on this rate transient analysis.

DR. AMPOMAH: Yeah, so my biggest concern is about the 20,000 and then the 15,000. So I just want to be clear. Are you saying that -- let's see. Is it your testimony today that your rate is more or less comparable to the amount -- or analysis from the 20,000?

MR. TAYLOR: So I think that notable analysis of the C108s represent the high side cases. And -- and yet if we turn to page 156, you'll see that that high case peak of these Veritas wells, 20,000 barrels of water per day, in one case 50,000 barrels of water per day, which agreed exactly with our -- our assessment there on the C108. Or as noted on the Severitas well, we -- we had our maximum at 15,000 barrels per day with our average at about 12,500 barrels a day.

You can see here from this plot on page 154 that the simulation is showing a -- the high case at that 12,500 barrels a day. So you see why it may be overstating the amount of injection that we can potentially see in this location.

DR. AMPOMAH: Yeah, so that is my concern. Because let's say we agree to 20,000 barrels per day. Now, before I move on, let me ask. So these were there to analyze what is the maximum injection rate for either the maximum? I cannot recall.

MR. TAYLOR: So what I recall, I think between 20 and 30,000 barrels of water per day.

DR. AMPOMAH: So I asked this question earlier to your colleague. And then he told me -- he told the Commission that in New Mexico, it is very small. But the maximum he has seen in Texas has been about 10,000. Yeah, that was part of the testimony.

MR. TAYLOR: Yeah, I -- I know there are some wells that have injected 10,000 barrels a day. Our Chevron wells and one of the ones that we had actually has a similar maximum rate on it as -- as what we would see in that -- I think in the Severitas well. And it's a shallow one in Texas. It's been averaging about 12,000 barrels a day.

So it -- it really depends on where you are in the -- and there's a lot of wells there more towards the -- the east closer to the Papa Squirrel location that will put away 20 to 30,000 barrels a day, some even higher than that just depending on the permits that have been granted.

But important to keep in mind Texas has a much higher maximum surface pressure that actually results in the injection of bone fracture gradient.

DR. AMPOMAH: Yeah, not in New Mexico.

MR. TAYLOR: Right.

DR. AMPOMAH: So I just want to clarify that the people -- said, you know, two to 4,000 barrels a day. And at the maximum that they see based on the experience of our 10,000, that's been outside the state lines. So I don't know. Because I feel like 20,000 barrels a day, and there were based on your analysis, you are not that close to that number; right?

So my thought is would you agree to what NMOCD's saying and then probably be granted a lower rate and then the step-rate test down with that?

MR. TAYLOR: Yeah. We have no objections to the rules that were -- were pointed out by the -- use the separate test to guide the maximum injection pressure. You know, the -- the rate, the injection rates.

You know, there's a lot more wells than just these that were used to -- in the RT analysis. The report didn't really see it had -- but there's a lot of publicly available data we can look up and pull. But there's dozens and dozens of wells that are injecting about 20,000, 30,000 barrels a day in Texas.

So the -- the DMG is capable of taking a lot of water. However, as this -- you were pointing out a lot of that -- then Texas is above the fracture parting pressure, and so we're -- we are expecting much lower rates here in New Mexico due to the -- the guidelines set by the OCD.

DR. AMPOMAH: Let me ask. What about your assumptions that you utilize in their key analysis?

MR. TAYLOR: Can you be more specific about the -- which assumptions?

DR. AMPOMAH: So the first one that I saw is that there is a general system. So even that one, how does that translate to, let's say, a highly heterogenous system that you are used to dealing with. You know, and if you are using that, you search more like -- you explain more just why that conversation ran that higher rate. You know, how is that shaping up in terms of if they had continuous and then --

MR. TAYLOR: Yeah. Thank you for that question. So the -- the approach that we're -- that I like taking for these is the -- the simplest possible for what would explain the data that we're seeing. That -- and that's just to avoid a creative yet super convoluted model that might match the data but not really reflect reality.

And in a lot of cases, most every -- every case for RTA that we've looked at, they -- that simple model that explains the dataset is a homogeneous radial flow meshed with a cylindrical boundary. The part of the reason why we're -- that model shows up a lot is due to some of the noise in the data.

So a lot of these are surface pressure readings that we then have to convert into bottomhole pressures. And using the -- the rate data that -- to then be able to perform this rate transient analysis. So the -- yeah, so that's why that homogeneous assumption makes the most sense as our starting point and that explains most of the data. I think you can see some of that potential heterogeneity in the reservoir reflected in the permeabilities that we calculate.

As you recall, that core permeability shared on an earlier side showed less than 1 millidarcy. We're seeing a rate transient analysis arranged with that 6 millidarcy up to 30 millidarcy.

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So what -- what could be the cause of that?

Sometimes natural fractures that -- that you asked about in a previous question that could be present taking some -- some additional fluid out here on these Texas wells. Specifically, it could be due to induced fracturing from the high rates of pressures that are present in the Texas. So those are not -- that's kind of all reflected in this composite permeability calculation that we get out of the data.

Some of the other assumptions that we're using -- yeah, we're not really. Sometimes we'll model these with well bore storage most of the time. It doesn't really make much of a difference in the final answer, so we tend to leave that off. We -- well, in these cases, some of them have time dependent skin. That's when operations happen.

They -- and they'll do acid jobs throughout the life of the well and see the skin factors change. On all of our numerical simulations that we're showing here on the exhibits today, we're sending zero skins to represent the brand new well, cleaned up a better casing --

DR. AMPOMAH: So nothing really that different from the alternatives that you think is helping to understand your two cases?

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MR. TAYLOR: Yes, yes.

DR. AMPOMAH: So now what? If you look at the testimony now presented in your analysis in the area that you are proposing, you have -- the radial .32 millidarcy?

MR. TAYLOR: Yeah.

DR. AMPOMAH: So I am expecting around -- lower end. Should a range reflect that?

MR. TAYLOR: Yeah. And I -- and I do understand that -- that concern. I think that these models are very easy to -- to rerun with permeability assumptions. It's the -- we wanted to honor the analog data since we don't have, you know, really any analogs in New Mexico under that pressure, where you know, we have to use the Texas wells, which do have some different operational conditions.

You know, part of the reason why we want this pilot, they're requesting this pilot program is to actually get that data in New Mexico operating under the OCD guidelines to understand more about how the rock is reacting to the -- to an injection. What are we really seeing in terms of permeability?

You know, the -- the few core samples that we do have, are those reflective of the entire reservoir or not. And so there -- there's a lot of unanswered questions that we have right now. A lot of uncertain data we are hoping to resolve in this pilot project.

DR. AMPOMAH: So in the modeling that you did for the two wells, do you know whether the formation really took most of the water?

MR. TAYLOR: So since these models are ultimately homogeneous and ultimately simple, it really just comes down to -- it's mostly collated with their thickness. We think upper, which is a Y, and injection rate is correlated to -- to thickness.

So the thicker one would take more -- more water in the models, so in this case it would be the -- the Cherry. The porosities do -- do impact that a little bit. But being as how close these are with these models, it's -- they give a thicker interval tends to hold more water.

DR. AMPOMAH: Just so I understand, so before the true potential injection zones, you assigned the same porosity?

MR. TAYLOR: No. As you'll see on slides 154 and 156 on the tables, those are the inputs into the model so that you have different porosities based on the -- from the geology at those locations.

DR. AMPOMAH: So what were the fracture

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pressure ingredients that you utilized in this one for either of the wells?

MR. TAYLOR: So this model did not take into account fracture pressure. This is the very simple radial flow homogeneous model.

DR. AMPOMAH: So in my mind, I'm trying to correlate the significance of the arms to the rate that you want -- So it sounds to me like this is a very simplistic model. And looking at how simple-looking it is, you know, maximum injection rate, it's not really up to answering our question.

MR. TAYLOR: This -- I can agree that I can thank the -- the rates that we requested were on the high side and then we wanted to socialize those -- those high in potential numbers based on what we're seeing in Texas and how this is possible in the DMG.

And just so that we're not -- we didn't want to come in and request 5,000 barrels a day and then have well, the potential for 20,000 barrels a day. We thought it would be better to err on the conservative side of requesting for more, higher rate at these given pressures and then learn through this pilot what is actually possible in -- in New Mexico.

There's just -- there's a lot of uncertainty on the rates. Much more confident in

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the -- the pressure assumptions and the total storage in real life as well. But the rate is really a big question. That just comes down to that -- that uncertainty and permeability to have all these tracks going forward.

What does the permeability really look like on a macro level as the well accesses the reservoir? And we won't understand that until we have some injectors in the ground and we can do a similar analysis on them.

DR. AMPOMAH: So I'm going to ask you based on the analysis that you've done, in your experience, you know, how is the high volume injection in the shallower areas that you are proposing, how will the impact -- you're going to build a pressure pit. So how is that going to impact future injection --

MR. TAYLOR: I -- I think this is why it's important to space wells properly. I do agree with the proposal that the OCD put forth that the wells be at least a mile apart. You know, Chevron, we see a lot of operators out there on the side in Texas.

They'll pack their wells really close together in whatever position they have are being that's wasted. The capital or really this here have been injected into the exact same container. So we -- our view is to space our wells out appropriately right now I think in the -- in our entire Harris, New Mexico field, where Severitas is, we have a potential three more locations we've identified with proper spacing and which I think is at least about a mile and a half to two miles apart.

But this is something that I don't recall exactly off the top of my head, but I think that's -- you know, relative to the -- the range of it over in the -- near Papa Squirrel and our Salado Draw field, we have two additional locations identified and properly spaced out.

It's not our intention to pack these wells in closer. I think I'm, you know, kind of extrapolating your question a little bit. If -- if we pack a lot of wells too closely, then the water pressures will increase it a lot quicker. It's not something we want to see, and we want to be able to efficiently use the -- the reservoir in that storage capacity. From my -- from my perspective, that cumulative storage number is the most important number. How much is this well going to be able to take over its -- its entire life?

DR. AMPOMAH: So on page 157, you apply

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the pressure showing us how the pressure needs to be away from the well bore, but I really wanted to see how the pressure is building up with regard to time. You know, in the more, like, pressure so I can really see how the pressure is building up based on the rates that you are using. I'm sure you have that.

MR. TAYLOR: Yeah. Yeah, we can -- we can for -- transform it into that. The way we presented it here was the time is really represented by those -- those different curves that we had. They all go up on the chart. That's the time. And then I tried to give a sense to that on the -- in the box there, the -- be calculated that timing there, that four-year, 11-year, 23-year et cetera.

Again, we -- the way we should have presented this data was more in terms of distance, as you said, rather than through time.

DR. AMPOMAH: Can you comment on the boundary conditions? So I know that in your application you said it's the closest.

MR. TAYLOR: Yeah.

DR. AMPOMAH: So is it really closed.

MR. TAYLOR: So based on the RT8 data that we've seen, these wells really are our closest. We haven't found one yet that is in the DMG that has an arbitrarily large boundary. They all -- all of the boundaries tend to just show up within a few months. So we got to -- it's a finite here. They gave us each model followed by that circular reducing on the wells quite well.

In reality, the shapes get, you know, oblong. They could be rectangular. We don't really know. But the -- the important thing is that they are finite and we can represent that finite, that potential area of impact quite well through a cylindrical reservoir model.

DR. AMPOMAH: Yeah. And you obviously did hard work. You did an amazing analysis. So thank you.

MR. TAYLOR: Yeah. Thank you for your round of questioning.

MR. FUGE: Now, I take it there are no questions?

MR. FUGE: I only have one. And it may just be implied from the analysis here. But I'm assuming when you did your sort of individual well decline and then the El Mar Field remaining reserves, a check was done. There are no pending applications that would suggest any interest in this area or these formations?

MR. TAYLOR: I don't recall. I -- I did not do that exact -- that check even with the outlines. We're back to -- look at that.
MR. FUGE: Yes, please.
MR. TAYLOR: So yesterday, we were -- I went back -- some questions and just went back to see when the last was -- and so it kind of tells me in -- in short what I think OCD kind of -- first of all, she went -- with these Cherry Canyon behaviors -- didn't even -- didn't even require -- we don't have an exact -- I think there is some -- some --
MR. FUGE: Any other questions for the witness?
MR. TREMAINE: No.
MR. FUGE: You may be excused.
I think I'm going to order to adjourn for a short break. We will reconvene at 3:30.
Then you have one more witness?
MS. BENNETT: Right.
MR. FUGE: Mr. Tremaine, how long do you expect you'll need for your first witness?
MR. TREMAINE: Our first witness will be pretty quick, so maybe 15 minutes.
MR. FUGE: So at least coming in, just sitting in, and so you know this at the outset.

Somebody had a harder stop at five today. But at minimum, we're going to do Chevron's last remaining witness and OCD's first. If we have some additional time, we can discuss that as we're moving forward.

So we will return at 3:15. I mean at 3:30.

(Off the record.)

MR. FUGE: Let's get back going, folks. And I know it's a little toasty in here. I have submitted some request to central, wherever that is located, to drop the temperature a little bit to the extent they can.

But we will go ahead and get started with Chevron's last witness.

MS. BENNETT: Thank you.

MR. FUGE: And since, Mr. Comiskey, we've already sworn and recognized this, I think we can just go into the substance of his testimony.

MS. BENNETT: Thank you very much.

EXAMINATION

BY MS. BENNETT:

Q Yes. Mr. Comiskey, you remember that you were sworn in? Do you agree to tell the truth?

A Yes.

Q So this morning you gave us an overview of

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the pilot projects and some of the work that's been done. And now we're transitioning to a different part of your testimony. And so what's the purpose of the testimony you're about to give?

A So a part of my own projects, one of the things you'll notice, we did a -- and took a very thorough review of seismicity at the Permian Basin. This is one of the cornerstones of -- of, you know, why we're looking into this kind of project for produced water optionality. It's partly due to the fact of the increase of induced seismicity attributable to somewhere across the Permian Basin.

So through these pilot reviews we undertook -- and we'll go through the review that I undertook to assess seismicity risk for these two pilots and just an overall setting of seismicity through the Permian Basin.

Q Thanks. And let's start out with your first slide, which is a seismicity review slide.

MS. BENNETT: And for the Division -- I'm sorry -- for the Commission, for reference, and for our other parties, we're starting on page 126 of the materials.

BY MS. BENNETT:

Q So let's start with page 126. And if you could orient the Commission to the slide.

A   Yeah. So again, the map on the right is just the map you've seen probably a dozen times already today of the two locations, so I won't harp on those. The thing on the left is modified from Zhai, et al. And it's -- it's focusing on Permian Basin. So what I did is just -- it does a good job of explaining, I think, the major operational practices going on on today's Permian Basin.

And so if you look at that, we start with the caprock, which we touched on a little bit. And then we get into the -- the shallow disposal layer, which in this case is the DMG. Below that are the Avalon, Bone Spring, and the Wolfcamp production intervals. And then you go further below that into a deeper disposal interval, which is typically referred to as the slurry or admission carbonates or deep disposal. And then below that is a basement.

And so what I've annotated on there are kind of three colored blocks, a pinkish, reddish that looks a the shallow injection. And roughly the depths here in Southeast New Mexico of about five to 7,000 feet. Production again that's referring to major unconventional development and production of roughly about 6500 to 12,500 feet.

And then deep injection is roughly about 17,000 feet to about 20,000 feet. And then what I've labeled there below is that seismicity, which I'll show in the -- in Southeast New Mexico it's roughly located about 20,000 feet or greater.

So you can see just the vertical differentiation between shallow disposal in the Permian and then the deep earthquakes that have been attributed to deep disposal. And so this kind of just sets the -- you can see the schematic there kind of a little bit on the left side.

You've got, you know, disposal and pressure front perturbation, which my colleague Bryce mentioned on just a minute ago. You've got production, which also creates a -- a pressure response and then deep disposal again. So your -- you have various sources and sinks of pressure as fluid is withdrawn or -- or molecules are withdrawn or rejected, given a -- a specific operation.

Q One last turn to your next slide, which is slide 127. And can you briefly describe this slide, and in particular where this information comes from and what it represents?

A Yeah. So this comes from the OCD oil and gas map. So what I've labeled here obviously this is

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the locator. I've -- I've labeled the -- the two locations for the pilots there with the blue stars, and then the colored bullseyes represent the current seismic response areas or SRAs in Southeast New Mexico.

So the colors there represent different radius around that, so the also yellow and/or red or orange circles, if you look. The small circles are earthquakes of a certain magnitude. Those are either 2.5 to 2.9 magnitude. That's 3 to 3.4. So 2 to 2.9 are yellows, the oranges are a 3 to 3.4, and then the reds -- there's two reds -- are above the magnitude 3.5.

Those levels are defined by the OCD's seismicity protocol that was announced back in 2021. The associated colored bands of red and orange and yellow represent different radiuses around those events, representing red for 3 miles, orange for 6 and yellow for 10. And again, those are derived from the OCD's seismicity protocol from 2021.

And so what this is trying to show about the various seismicity protocols within Southeastern New Mexico, and we'll go through some of the slides and looking at in particular one of the SRAs, which I've labeled a county line, state line SRA, which is --

borders Eddy and Lea County and also Loving and Lea County.

Q And so those depict the Papa Squirrel as it is within one of the SRAs?

A Yes, it does depict Papa Squirrel as to be within one of the SRAs. However, as I'll show in future slides, the SRAs focused only on deep injection and not shallow.

Q Let's turn to the next slide then. And can you orient the commissioners to what this slide is then and what you're showing here?

A Yes. Again, so here's an inset map looking at Eddy and Lea County, and also the northern part of the Delaware Basin of Texas. Again, I've highlighted the two proposed titled SWD locations with blue stars. I've also highlighted the county line/state line SRA and a -- and a black oval.

The earthquakes on this map are -- are colored circles represented from a magnitude 2.5 to a magnitude 5.0. So what I'll go on this is the source of this information is the USGS website. They are the authoritative source on earthquakes in Southern New Mexico. They're not in Northern Texas. That is the TexNet, but TexNet or USGS reports of Texas. So the USGS is essentially now the -- a one-stop shop.

So those earthquakes are colored by magnitude. Most of those earthquakes occurred from 2019 onward. The two plots on the right if you look on the -- the histogram, you'll notice the label is depth of the event over time. So it's depth in feet from surface level. And so the top of hot is referencing just the events within the county line/state line SRA.

The bottom is year, and you can see the events with the necessary started within 2019, kind of regressed since then. It started to pick up really in late 2020 and has progressed fairly consistently until late 2022/2023 where we saw a -- a reduction, and I'll show that in a future slide.

The bottom plot is -- is looking at the Northern Culberson/Reeves SRA, Texas. The reason for showing this is it's also an area of seismicity that's been attributed to deep disposal operations. And you can see the number of earthquakes there. There's obviously quite a few more earthquakes over time in this plot.

But again, it just relates to the depths of the event. So both plots, you can see the depths are well over 18 to 20,000 feet. That is many thousands of feet deeper than -- than conventional development

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and/or shallow disposal, which I'll show in a future slide.

But the main purpose of this is just to orientate everybody with the seismicity that's going on within the area of interest, the magnitudes, and the trends over time and the depths.

Q And so turning to the next slide, because you've taken a closer look at some of the events that have occurred in the area?

A Yes.

Q Why don't you walk us through this slide?

A So I'll start on the -- on the right of the slide first so that -- this is a depth of operations versus seismicity. The depths that you'll see here from the formations are derived from well tops. So there's a fairly accurate -- so the step goes from 0 to roughly 30,000 feet, again from surface.

So the first color block on there is -- is relation to the Papa Squirrel. So the proposed injection interval that you've seen is the Bell and Cherry Canyon formations, roughly 4600 feet to 7,000 feet.

Below that, you'll see the Avalon production, roughly about 9,000 feet, the Bone Spring production, roughly about 10,000 feet, the Wolfcamp production, roughly about 11,000 feet. And then below that again are deep injection. And that's again roughly 17 to 20,000 feet.

Even below that again are earthquakes. So the earthquakes that occurred and you referenced the map on the left to see the location of the earthquakes in XY. The location of earthquakes are again well below the proposed DMG location interval and again below the -- the deep SWD interval.

If you look on the map on the left, you see the earthquakes again colored by magnitude. That magnitude scale is consistent through all the slides, I should note. The -- the red dash outline is roughly the -- the county line/state line SRA.

And then the blue boxes are deep disposal wells. As I've mentioned this -- the SRA did not impact any shallow disposal wells. It was only focused on deep disposal wells given the preponderance of information that was put forth a couple years ago from those -- the industry.

So all the blue wells in that area have been impacted by the SRA either through enhanced data reporting, curtailments, or shut-ins depending on the distance from the earthquakes. The reference there, there's that orange/reddish circle right there. Yes, that is a magnitude 4.0 event that occurred in July of 2021. That was really the catalyst for the -- the SRAs and the -- the change in the protocol in establishing this SRA.

I'll talk a little more about the -- the evolution of this SRA over time. But the main purpose of this slide is just to orient to begin within the county line SRA and in particular the Papa Squirrel as it is in the SRA. The depth of the proposed injection interval, the depth of the production, the depth of the deep injection, and when the seismicities occur.

Q Thanks. And down here, this is the part?

A The Papa Squirrel, yes. The Papa Squirrel is the black diamond on the map label.

Q Right. Anything else you want to tell about the slide? If not, we can move on.

A No.

Q So the next slide discusses curtailments, which you were just alluding to, so why don't you take it away and talk a little bit more about curtailments and why that's relevant to today's discussion?

A So when we look at seismicity, the question is what's inducing the earthquakes; right? And there's a multitude of hypotheses that can be looked at with inducing earthquakes. Not just on the -- in the Permian Basin, but anything due to anthropogenic events. And anthropogenic meaning human caused.

So when we looked at seismicity in Southeast New Mexico as it began to -- to take an uptick, we're starting to look at -- see the correlation between, you know, analog studies, correlation between deep injection and the seismicity, things like that.

So there's a couple key things on this that I think add -- give us a better understanding of the correlation between deep disposal and the seismicity. So the same map on the -- that was on the previous slide is shown. However, there's a blue kind of colored in circle-ish oval. And what that's depicting is just the initial seismic response around the initial magnitude 4.0.

The reason why the red area is much larger is that's incorporating events that trend up towards the south, southwest over time towards the state line. That's created a much broader polygon. But the initial kind of AOI was that -- that shaded -- roughly shaded curtailment area.

And so if you look down below, you see the magnitude 2.0. That's within the initial 4.0 response. And again, it's just magnitude 2.5 and above on the USGS. And you can see the events over time.

The dashed line that is noted on that plot on the bottom with OCD becomes labeled is the point at which the OCD enacted their response, thus curtailing deep disposal within that area. If you look up at the plot above, this is a plotted SRA. The county line/state line SRA deep volumes and barrels of water per month from the OCD website dating back to January of 2017 essentially through reporting in October roughly.

And you can see that trend continuing up over time, reaching a max of nearly 8 million barrels a month in early 2021. However, you can see a sharp drop after that OCD curtailment in essentially December of -- of 2021, January of 2022.

And so if you look at that OCD curtailment drop and you look at the -- go back to the bottom plug. You can see the seismicity before the curtailment and the seismic reactive curtailments are -- are very different.

And you notice that there's only one event on that bottom plot kind of after that April 13 date. We -- I pulled the date up until just a few weeks ago. There just haven't been any events. So that's why the plot stops. There just haven't been any earthquakes in that -- in that oval.

If you go and look now on the county line SRA earthquakes over 2.5, this is taking into account the whole county line SRA. Again, I note the OCD curtailments. You still see seismicity has continued. You could probably say it's probably equal to what it was before. Again, that's representative of the seismicity has migrated. Again, the curtailments have only impacted a certain area, not the whole, broad area.

The -- but the key to this slide though is that within the area curtailments on the deep disposal volumes only -- and I want to reiterate there was no shallow curtailments in this -- there seems to be a strong correlation between the curtailments of the volumes from the OCD and the seismicity within that immediate response area.

And this is analogous to other areas globally that have seen responses in injection due to seismicity, curtailments, or shut-in, and the mitigation of seismicity over time.

Q So this preserved -- that we intended to talk about earlier, but it's here as well, so why don't you describe this slide to the commissioners, and why was it included in here as well?

A So this is -- this is somewhat a cornerstone of the pilot program. It just kind of relates to -- to, you know, where this water's going. So you've seen curtailments. Production has continue to go. I'm sure, you know, New Mexico should be very proud of being the second largest oil-gas producer in the United States.

So the plot on the bottom -- this is just focused on Southeast New Mexico, so this isn't representative of the entire state, just focusing on Southeast New Mexico in the Permian.

You can see an increase in - in green. That shows up as green. But oil production, that's BOE equivalent per day. 2019 obviously till 2023 when pulled the data, and that's roughly about 3 million barrels a day or so. BOEs again.

The darker blue line, that is average water injection. Again, this is Southeast New Mexico. And so you can see that premise is roughly flat, but did come up a little bit in 2022, then it's roughly been flat. However, you know, for every BOE that's produced in the Permian Basin, roughly it's anywhere between two and a half to five bags of water.

So -- and you expect to see that trend increase relative to production. So if you look up the total water production trend, seems to -- you know, kind of relates to that. So you can see that Delta is roughly about 2.5 to 3.5 four to one. So where is that water going?

You have increased oil production, and the injections here will be flat. Most of that water is moving across the state line. It's being injected into Texas roughly to the tune of about 3 to 3 1/2 million barrels a day is being injected.

And I -- I would argue that probably 90 percent if not 95 percent of that water is being injected into DMG disposal wells. So when we think about, you know, reductions in -- in, you know, we've -- we've talked about limited DMG disposal and Southeast New Mexico as we document its -- today, talk about predominantly deep disposal in Southeast New Mexico.

However, the rise of seismicity has curtailed several areas of deep disposal. It's put more -- more pressure -- pun intended -- on the disposal network. And there's been a big move to move a lot of that water across the state line into Texas.

Q Thanks. This slide is entitled "Chevron Undertook In-Depth Technical Review." And this slide isn't designed to go through that technical review, but maybe more or less to be a summary of the technical review?

A Yes. This is just a graphical representation of the technical review. And so the previous slides talked about the seismicity, where it's occurring and operational things. Things that we can observe, things that we can -- we can see.

This is trying to look at, you know, what's causing the earthquakes and what are the earthquakes telling us about the earth? What are they telling us about the relationship to stress, relationship to many different properties we look at.

And so all red -- everybody to the -- again, the plot on the right -- the figure on the right is the same figure again on -- and I'll talk about that dash line here in a second.

But if you go to the figure on the left, the map, you can see that this is again a map of roughly the same area of Lea and Eddy County and Northern Texas and the Delaware Basin. And then I've -- I've labeled several things on here, so I'll walk through that.

If you notice the -- the blue triangles here, those blue triangles are seismic monitoring stations. This is Chevron's and the industry's operator network that many companies have subscribed into. And essentially, it's a -- a very robust network of seismic monitoring stations.

Across the Permian overall, Chevron has access to over 220 seismic monitoring stations, which gives us a very robust understanding of where the earthquakes are occurring. Space and time, but also very highly accurate understanding of the depth, which is very consistent.

A lot of the times, you'll see the -- either through other public reporting agencies the depths are off. They could be off by 10,000 feet because they don't have enough stations to detect the earthquakes accurately. And this has been around for several years, and it's actually expanded into Mexico more frequently in the last couple years because of the increase in seismicity.

The second thing I want to note on this are the colored -- we call them beach balls in -- in seismology. They're actually moment tensor focal mechanism solutions. But you can see they're colored. They're colored according to the magnitude scale. And I apologize that it's hard to read. But the -- the darker colors are lower magnitude starting at about a magnitude 2. The warmer colors go up to I believe a magnitude 3.8 or 9 on this map. And so that's just the magnitudes, so the beach balls are colored by magnitude.

What the beach balls tell us and how you can see they're slightly different shaded -- and again on the scale it might be difficult to see. But you can also -- if you take a glance at the map on the middle, you can see similar kind of gray beach balls. And what these moment tensor beach ball solutions tell us is how faults are moving.

So when an earthquake occurs, there's different -- different stations to detect different first motions and locate the earthquake. And that amplitude either up or down tells us how the fault moves each direction.

The -- the very key component to this, it tells us the geomechanical orientation of the fault on the subsurface. And so for several representative focal mechanisms, what I've done is I've labeled the spike, dip, and the rake. And those are key components of structural geology.

But what these tells us is which way's the fault leaning, so which direction is the fault? Which way is it dipping? And those can tell us about so log information, about the stress information in the subsurface. Is it a normal faulting environment based on the orientation of these mechanisms? Is it a reverse fault environment? Things like that.

But it's very critical understanding the stress 'cause that tells us how faults are stable and subsurface unstable. Some faults are stable. You could -- you could increase the "rosavar" [ph] pressure to a million psi and it'll never move.

Some faults are unstable. You could increase the "rosavar" [ph] pressure by one psi and they will move. So understanding that in relation to -- to the geometry is very important when we're thinking about induced seismicity and what may or may not cause it. So that -- that's a key component.

The figure on the top is just a representation of Andersonian faulting. And this is just a broad representation of the fault, this roughly dipping that we've interpreted here. They kept kind of becoming SRA area. The deep fault moved. And it's roughly dipping about 50 degrees, striking about 65 degrees, which is roughly parallel to SHMax.

So the -- the red lines on this map are interpreted based on many different types of data, but the SHMax in the direction's roughly about 70 degrees. So 65 degrees for the strike. Background stress is roughly 70, so they're very well aligned.

So in a normal faulting environment, when you have a fault that's probably parallel to SHMax, it's more prone to slip, meaning it's more likely for movement to occur than fault let's say on an orthogonal map and I'll show a simplistic model on the next slide on -- on that. The -- the map in the middle is a publication from Jens, et al., and Mark Zoback at Stanford. This was 2016. There's been a subsequent update to this.

But this just shows a very good example the stress direction accomplished of multiple data, some of which -- a lot of which industry provided, including Chevron, to this. And this just gives a -- a good understanding of the stress direction. So the -- the cue in the map in the background is colored by normal to strike with faulting environment.

And then the -- the indicators that directional arrows on the map roughly indicates a stress direction, the maximum horizontal stress direction, again, which is very critical to understanding fault.

So if you -- if you look at all that, the -- the kind of the dash line is something we've interpreted on this as a deep basement fault that moved. And so that's just kind of based on all this information, we're able to ascertain from the geology ascertain the strike and the fault, the dip, the background stretch direction, the stretch direction of the fault, and those two limitations, what's prone to slip, what's not prone to slip.

So when we think about how we manage new seismicity, this is a very critical component to constructing your risk management plan when you think about, you know, disposal operations or anything in particular that has a -- a net change on the reservoir or pressure change.

So the next two slides to go through are just basic seismicity reviews of -- of two locations. So the -- the Papa Squirrel. There's a 10-mile area of review on that. You can see the earthquakes again. We've talked about this before. You know, the earthquakes are -- are deep. Again, the injection interval for the Papa Squirrel's about 4500 to 7,000 feet. Earthquakes here are well over, you know, 20,000 feet or so, so there's significant separation between the two.

I should note that the separation between those are many thousands of feet at very tight on impermeable rock. Obviously, we have to use

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hydraulics to stimulate the out of commission reservoirs. They won't flow on their own. So there's a lot of impermeable rock between the shallow injection or goal and where these deeper quakes are occurring. And then Papa Squirrel, the closest neck to two and a half is roughly 5 1/2 miles away from that bed.

The next slide is probably one of the more boring slides we'll see today. Thankfully there is no -- there are no events in New Mexico within the 10-mile AOR. I did pull up some events in Texas. Those are pretty small magnitude events. I did label again, as reference, this is again just -- the numbers have changed here relative to the Severitas 2 State SWD 1 location.

In the depths -- you could see the depths of the earthquakes here very deep. You will note that the plot stops in 2022. It's not because I didn't -- I didn't want to pull anything more recent. It's just there were no -- there had been no earthquakes within this 10-mile AOR over that timespan.

So that was kind of a review of kind of the seismicity review around this. I -- I will be remiss if I didn't talk about shallow DMG disposal. And based on the exhibits from OCD, I'm glad I brought this -- this paper up.

And so there -- are there -- there is earthquakes in Permian Basin attributable to shallow disposal. Absolutely. And I will go through a very good case study from Horne, et al., that was published a year ago and looked into this in much detail.

So the map on the left has a lot of information on here, the reference is there and all the references I've used are -- are cited. I would recommend that Commissioners go and -- and look at this if more interested. There's a lot of information on it, so I'm not going to go through every component of that. But what I'll note is I did the zoom in and you can see the red arrow. And this is looking at Southern Reeves County.

Southern Reeves County, the earthquakes here are -- are much shallower. They are in the Delaware Mountain Group. And so, you know, the question had come up, you know, we have earthquakes due to shallow injection here. Why not, you know, in Southern New Mexico or other areas? And the answer is geology and stress.

So as I mentioned before, faults that are oriented roughly parallel to the stress direction are more prone to slip. And at Permian Basin, the stress orientation rotates. See down here, it's roughly -- the stress direction is roughly north/northwest to south/southeast. So it's roughly -- if you look at it, it's roughly oriented about, you know, 330 degrees. Whereas as I just showed you recently in Southern New Mexico the stress orientation is about 70 degrees.

The stress rotates. It is very unique to the Permian Basin. There are a lot of scholars out there that are trying to understand exactly why it rotates. There's a lot of hypotheses I'm not going to get into today. But it does rotate. Which means its -- one fault in a certain area may be stable. One fault in the other area, same direction may be unstable.

Look at the faults in Southern Reeves. You can see their trend on the seismic cross sections. The two slides there. One is black and white. The other is colored. Just looking at a deaf slice and a coherent slice of seismic data. And you can see those faults are roughly trending about 330 degrees, right, north/northwest. They are -- they are oriented and they have -- it makes them prone to slip.

The -- the bottom plot and the colored scheme down marked E shows numerous shallow injection wells in the yellow and green intervals. Those are the -- oh, sorry, the -- in the light green colored interval, those are active shallow injection wells that are injecting into the Delaware Mountain Group where those stalls are posted.

And the likely hypothesis there is that those are increasing the far pressure reservoir, which reduces the effective stress on a fault. And that -- when that happens, it becomes unstable, and it moves, generating earthquake.

So this is the unique set of circumstances, we talked about faults. And you'll note that we have -- we have not shown any slides like this because when you go in and interpret these, these faults in Southern Reeves County are -- are very obvious in seismic data.

When you move to other parts of the basin, we cannot see these structures. And there's likely just because of the different faulting and the different stress domain when the basin was formed, these are thin-skinned faults. These are young. These do not connect into the basement. They tip out into the Wolfcamp. It's likely because the timing of the basin range extension those dates, the deposition of the Wolfcamp.

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But they are there, but we cannot see these similar type structures in Southern New Mexico, at least on the -- on the distribution on the scale that we see down here in Southern Reeves County. That's a very distinct -- also cannot see these in the Midland Basin either.

Q So when you say we don't see them or you can't see them in the Permian or Midland, what does that mean exactly? Does that mean that you literally can't see them or they don't exist or you don't have to be as concerned about them?

A We can't see them with this fidelity. They're not as -- they're not as clear-cut. These are -- these are very clear. They offset stratigraphy. You can see them very blatant in the seismic data.

You could bring a lineup from ten geophysicists and eight of them would agree. You can't get all ten. But eight would agree that you could see those. If you brough up a similar cross section in Southern New Mexico or other parts of the Permian Basin, it's much more harder to distinguish them.

And the thought is it's -- there's a change in the structural geological in this area. There's definitely change in the stress direction as well.

Q We're about to move off. Well, we have a couple more slides on there.

A Yes.

Q So let's talk about those, and then I think what I would like for us to discuss is your conclusions based on these slides once we finish up with this, the orienting on this one.

A So the next slide, which is I believe 136 in the packet, this again looks at that. So this is from the same study. At least the figures on the left are. And so again, we're looking at SHMax, the direction here again is roughly 330 or 140 degrees, depending on which way you look at it. Northwest-southeast.

And again, the -- the researchers here took the fault planes. They interpreted those two figures in the panel next to the rose diagram, and you can see that these are almost vertical faults. The different values are colored roughly 60 to 70 degrees, even higher. And these are oriented roughly parallel to SHMax, so again making it more prone to slip.

But down the right is using a model. This is from FFP, some publicly available program. And it's very simplistic, but it does a very good job of visualizing the differences in how important stress direction is.

And so I've drawn two orthogonal faults with each other. And its stress direction here again is roughly about 140 or 330 degrees. And you can see that the yellow fault, just based on its orientation, the core pressure model for it to slip is about 300 psi.

A fault orthogonal to it is roughly about 900 psi. And so just based on those two conditions alone, you can see the difference -- the difference in the two and how important just the stress direction is on fault stability.

Again, one of the things I want to note here I think is a very good part of the articles. If you look at the Coalson events that are colored on the bottom plot with the -- the beach ball diagrams again, that actually is today where the -- where the magnitude 5 reoccurred as well in this area.

You can see the colors of those events. Those events are roughly -- the beach balls are roughly light to medium and dark green. The bottom plot of that corresponds to the depth of about 7 to 9 kilometers in depth from the surface.

If you look down further into Southern Reeves County, you can see that the beach balls were

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numbered 11, 12, 13, 23, 5, 17, and 16. They're roughly orange-ish color, which means they're roughly about 3 to 4 kilometers in depth.

So there's a strong depth differentiation between larger earthquakes you see in the Culberson SRA, which I noted before, and the events in -- in Southern Reeves County. These are shallower. They're not as large, and there's a depth depreciation I'm getting off initially.

The plot on the right is modified from Zoback and Gorelick. And I think this is a very important plot when I think about the potential size of earthquakes. It is very difficult to get a large earthquake in a very small hole. When you think about earthquakes globally, the large earthquakes, the San Andreas Fault, the earthquakes that occurred down in Mexico, in Japan, those are on faults that are hundreds and hundreds and hundreds of miles long. They generate very large magnitude 7 quakes.

There's a direct relationship -- and this is what this plot is -- is showing -- between the -- the length of the fault and stress built up in the fault and magnitude. And the correlation is to have big earthquakes, you have to have big faults.

So we're thinking about shallow disposal, shallow seismicity. When we think about shallow lineaments or faults or subsurface. They don't have the stress built up over time to degenerate large, appreciable earthquakes. That's just because they're young. They're not as cranky. And they're -- they just don't have the stress built up.

When you get larger earthquakes, magnitude 5 3, magnitude 5 4. Those are on larger faults, and those are generally buried deeper because they have a higher stress built up. And that's just a general trend in -- in seismology in relationship to faulted pods.

Q And so we're about to move on from seismicity. So I was hoping you could find a summary of your conclusions for admission, and then I'll have a follow-up question after that.

A So when we look at seismicity in -- in relationship to the Permian Basin, we did a thorough review, looking at, you know, what's -- what's inducing earthquakes across the Permian? We recognize there's a concern. We're concerned as well about the increase in seismicity and how it relates to -- to saltwater disposal operations.

And when we look at, you know, shallow disposal operations and reflect on seismicity, there's key components we have to consider. It's the fault orientation. It's the -- the fault length. It's if there's a fault there. It's the pressure change model to understand what potentially slip is and how those are oriented in respect to each other. And so looking at all those criterion together, you know, we feel that there's a very low risk of -- of appreciable seismicity associated with -- with these two locations or a shallow disposal in Southeast New Mexico.

There is, however, as documented, a much larger risk of seismicity from deep disposal, which again has been documented and has been implemented to through the OCD's protocols around seismicity. And so I -- we feel that this, you know -- looking at these pilots provides an optionality to support disposal in a manner which will mitigate seismic risk.

Q So one of the things that I noticed when I looked at your slides is that there is a lot of information on these slides. But you've also come to a conclusion. So Chevron wasn't just wanting to show the Commission this end result; right? You wanted to also show the Commission the depth of analysis that you undertook to reach this conclusion. So you sort of wanted to show your math?

A Yes, that's correct. Yes.

Q And are you familiar or have you reviewed OCD's conditions of approval or conditions for approval of administrative applications in Exhibit 11?
A Yes, I have.
Q And was there a condition of approval or condition for administrative applications that assessed seismicity?
A Yes, there was.
Q And do you feel like the seismicity review that you did for these two wells would be consistent with that requirement?
A Yes, I do.
Q Let's move on then to the next two sets of slides, which relate to your data collection and first of all your response protocol.
A Yes.
Q So if you could explain to the commissioners what this slide is and how you developed it?
A Yeah, so -- so this is -- this was work that was undertaken, I mentioned earlier today, through the NMOGA work group. And so I'd like to apply industry, several of which are in the room here from other organizations that helped support this framework. And I think this is an excellent opportunity for industry to work together and with -- with regulators and

others on managing turned around disposal.

And so what this -- what this puts together is essentially taking the culmination of what you heard today on concerns around disposal interactions with potential production intervals, you know, potential seismicity, things like that, and it puts together a framework which industry can work through and work together on to not only document, collect data, assess, report, and then manage potential risks.

And so I -- I won't necessarily walk through all the text on the right. I'll mainly just focused on the -- the colored letter -- the colored words on the -- on the left side. But essentially, this is looking at, you know, once -- once the pilot starts up and starts injecting and monitoring, and we'll talk about the data collection. If there's an event that kind of triggers this response, this is how this will go in theory.

And so if there's an offset producer that -- and this is mainly getting focused on -- on impacts to production, quarterly rights, things like that -- if there's an offset producer that determines that potential interference is occurring and we note that, you know -- we know we can work with monitoring our own producers.

We hope that other operators, if they see something that changes in their -- in their production profiles or their -- their watercuts overtime or any of those information you're bringing a spore to us, we'd like to set up a discussion. We'd like to review. Again, we -- we provide information on -- on FSI in this case or fracture stimulation interference or FDI. We'd like to review that and rule that out if that's a case of that -- that change. Today will be looking at the -- the stimulation times of offset wells.

And then if we ruled that out, potential additional data collection -- I think it's been mentioned, tracers, other data collection options to -- to ascertain potential communication. If we look at -- if there's no, you know, communication, you know, then -- then potentially no further interaction. But if there is, we'd take remedial action.

And those can be a number of things. It could be reduction in the pressures. It could be a reduction in the injection pressures and a reduction in the injection rates over time. It could be potentially plugging back some of the well. It could be a combination of all -- many things. Again, all of this could be documented to the OCD and to industry as we progress this.

And then if -- if none of this is successful, you know, we -- going down, we seek -- you know, seek resolution with OCD. We recognize the OCD has the authority to suspend operations at any time, and we support that.

But this is a -- I think a robust framework industry could work on in laying out a pragmatic data-driven approach to manage issues around injection -- in this case around shallow injection into the DMG in Southeast New Mexico.

Q And again, this was derived from stakeholder engagement?

A Yes.

Q And as you mentioned that there are operators in the room, outside of the room. And you've shared this with the Division in past meetings with the Division, this framework?

A We have shared this with not only OCD but also with State Land Office and other -- and industry as well.

Q You've been talking a lot about data today and how that's one of the key aspects of the pilot project. So if you wouldn't mind discussing the slide for Commissioners and giving the commissioners more information about the data you intend to get, but also why you think the data is important?

A So as you've heard many times today, we are -- Chevron has a vested interest in collecting a robust data program with these two pilot wells. There's been a lot of work. They've talked about a lot of uncertainty in shallow injection.

My colleague Bryce Taylor did some work on some RT wells, and he only used a few. 'Cause there's only a few wells that have actual data we can leverage out of thousands in the Permian. So we look at this as a very important opportunity to collect a lot more, a very robust dataset, not only for us but for industry to understand the potential issues.

Someone down here has listed out -- and I will note this is -- this is not necessarily every single piece of surveillance. We looked at these, and these are the things that we think are high priority. Doesn't mean there may not be other things on the table, you know, depending on what we'd look at. But these are the things that we think are high priority and part of our data collection plan.

So I'm going to briefly run through these and just their surveillance and what we're -- what's going to be taken in purpose. And I'm going to kind

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of label these into the -- the static perspective and the dynamic perspectives.

So first we have the -- the wire line logging procedure that's -- that's fairly standard in the industry. And so this is, you know, the quad combo logs, gamma ray resistivity, neutron density, porosity, sonic. And that's looking at, you know, the overall lithology and the reservoir, quality of the reservoir, stress, things that are core building blocks of the -- of the geology.

Or else they're going to run the XMRI log, which looks at fractures. We talked about natural fractures and things like that. It's important to understanding that, how it goes to mechanic worth model. There were some questions earlier about understanding the frac geometry. This is very critical to understanding that.

One of the things here, we're going to have downhole pressure gauges. Chevron as a program and any of our shallow disposal wells we drill in the Permian, we -- part of our standard protocol is to install downward pressure gauge.

It's very important to understand how pressure changes if we inject over time dynamically. Dynamically being a key component of that. Not once a

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month, not once a year, but continuously. Spinner surveys are something we've also looked at, understanding, you know, high prime interlay zones where the water is going through injection over time.

Water chemistry. Chevron has a robust water chemistry program. We look at produced water. This seeds into our -- into looking at other things that we look at around -- around potential beneficiary use and things like that. So this is a robust program.

As -- as colleagues we would be running defense and separate tests as well. So those are a lot of the somewhat static information that we could be collecting, some of the more dynamic data that we could be collecting based on information or tracers. Again, we talked about if there's -- you know, try to trace where potentially water is going -- is going out of zone, out of confinement. This is a good opportunity to try to understand that.

We have downhole gauges, deployed producers, monitor pressure changes or communication then production monitoring. This is something that, again, one of the -- the highlights and what I talked about earlier in locating these wells where we did and trying to take into account many different variables is locating these on top of our own wells.

It's very challenging sometimes for companies to share production data for obvious reasons. But given that these are on top of our own wells, we -- we can share data with ourself. And so this gives us the opportunity to have a really high quality rich dataset looking at production changes very proximal to the -- to the well locations.

So again, this -- we feel this is a cornerstone of our pilot program. We think this -- this is going to add a lot of value not only internally but also to the industry understanding, and not just in Southeast New Mexico, but across the Permian in general. This can be applied a lot of places. So we're very, very excited about this, but I think it's very important.

Q So the pilot project is a two-well pilot project. And so does the data collection sort of dovetail with the fact that you chose two wells as your pilot project?

A Yes. It -- it does.

Q And why is that? Do you expect different data from the different wells?

A We expect -- we expect different results from different wells, I think. Obviously, we talked about the geology difference in the modeling we came up with was different. So this allows us to be able to look at two different locations.

You know, it's very hard to form a trend if you only have one datapoint. And so we're starting with two. We might need three, but we -- we felt that this was adequate to try to further our understanding. It also dovestail in with other data collection we're doing in Texas with our operations as well.

Q Let's go ahead and talk about the next slide about the timeline for your data collection efforts.

A So this is -- this is a proposed kind of guideline. You'll notice it's kind of pre-spud execution. Injections start up and down the road. And so this should be looked at as a notional kind of timeline.

There's certain data that you will collect at one point in time. The logs will be run, and those are the logs, right, when we drill the well. There's other pieces of information like pressure data, production monitoring, you know, other data that will be collected over longer periods of time. They'll report it.

And so -- so this is just a -- just an overview of kind of how things will lay out from a -- from a general timeline as far as execution. So yeah, obviously, when we drill the well, we'll be logging it. We'll be doing the DFITs and the step-rate tests.

When we start injection, you know, we'll be, you know, performing, you know, and slowing down all pressure gauges, looking at how the pressure's changing, and doing some of the treatments, understanding how that is running spinner surveys, things like that, to understand how the dynamic well performs over time.

I'm feeding into, again, my colleague Bryce report on rate change analysis. So I'd say collect data, be able to execute that modeling work to see how the well is performing, looking at offset producers. So this is kind of a just a notional timeline that looks at how data will be collected over a period of time.

And this is -- this is, I think, very important to understand that some day it will come at once. Some day it will come over time. Some day it will -- will come continuously just based on the -- the nature and the flavor of the data being collected.

Q And so one of the things that you mentioned is a desire to be transparent and to share this data in a collaborative fashion. Can you explain a little bit more about that to the commissioners?

A Yes. So at a -- at a very high level that we're committed to work with OCD in providing this data in a public format so that everybody can -- can work on. This is one of the big conversations here about the industry on -- on how to proceed with this. I think this is a little bit new for a lot of -- of us.

And -- and maybe the OCD on collection and dissemination of -- of such a rich dataset. And so we look forward to -- if moving forward put the pilots working with the OCD on setting up a plan to -- to store and host data in a certain way.

Q And then the final slide that you prepared gives a summary of the key takeaways from your testimony.

MS. BENNETT: And I don't want anyone to get the wrong idea that it means his testimony is over though, because I do have a bunch of questions to ask him.

BY MS. BENNETT:

Q But I would love to hear your key takeaways from your testimony.

A So I believe I talked on -- on several of the seismic already, so I'll -- I won't belabor those. But I will continue that again. When we think about a lot of the data that's been proposed today. And Chevron is committed to collecting and providing a very robust and transparent dataset with these.

We feel it's very important not only to the overall success of the pilot program, but -- but just to the further understanding of some of these uncertainties that we've talked about and being able to provide a lot more granular information to perform more higher-level modeling to perform more in-depth analysis than we are able to just because we don't have enough data.

And we're modeling uncertainty on top of certainty when we could be actually modeling, you know, actual constrained information. And -- and so we support that -- we support that as part of our conditions of approval on -- on collecting data and disseminating it as well.

Q Thanks for that. One of the things that we talked about earlier today was -- this is kind of going back to a question that was posed to Mr. Merrifield about how many wells were analyzed to come up with a net porosity. And do you have an answer to that question?

A Yes. It was -- so that -- that worked to look at the overall DMG geological understanding took into account hundreds of wells across the Permian Basin.

Q The next kind of questions I wanted to ask you about were OCD Exhibit Number 11. Have you had a chance to review that?

A Yes.

Q And I just want to ask you some pretty general questions about it, correcting that I do not have them in yet. So you reviewed it and -- well, let me take a step back and talk about what Chevron did to prepare for coming to this hearing today.

Chevron evaluated offset DMG production; yes?

A Mm-hmm.

Q And it evaluated potential impacts on offset Avalon production?

A Yes.

Q And ensured adequate lower and upper containment?

A Yes.

Q Evaluated faulting and lineaments that connect as pathways?

A Yes.

Q Assessed seismicity to the extent relevant?

A Yes.

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Q Ensured adequate well bore design to protect SDWs?
A Yes.
Q You have come up with reporting for faults?
A Yes.
Q Safety monitoring and mitigation measures?
A Yes.
Q So looking at the -- well, do you think that those analyses are consistent with -- consistent with the Division's proposed guidance in -- in Exhibit 11?
A I believe so.
Q Would you consider those to be some sort of touchstones for the Division to follow when evaluating future shallow DMG applications?
A I believe so.
Q Let's see. I just wanted to take a quick look at paragraph 2, "Criteria for selection of the injection interval, excluding the Lamar limestone from an inclusion and department interval." Is that something that Chevron has done or is willing to do?
A Yes.
Q Excluding the lower Brushy Canyon from the permitted interval? Is that something that Chevron has done?
A Yes.

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Q Review of the AOR and assessment of evidence of natural frac systems or faults, is that something that Chevron has done?
A Yes.
Q So in terms of the well bore design and construction -- I'm not going to read all of this. But are these consistent with the well bore design that you have put forth today?
A Yes, it is.
Q We already talked about limiting the two main to 5 foot, 5 inches. We already talked about craving stimulation, additional testing and monitoring, conducting a cement bottom log for each casing string. Is that something that you had proposed to do in your original application?
A Yes.
Q Conducting a suite of open-hole logs over the approved injection interval and submitting this information to you if needed. Is that part of your reporting protocol?
A Yes, it is.
Q Conducting a successful step-rate test before injection commences. Is that something that Chevron is willing to do?
A Yes, we are committed to conducting a

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step-rate test, so I really would like to review some of the exhibits proposing this temporary test procedure.

Q And that's not because you disagree with doing a separate test. You just have some questions about how it is to be performed?

A That's correct.

Q Some inconsistencies in the volumes to be performed?

A Yes. That's correct.

Q Some inconsistencies in the volumes?

A Yes.

Q And then every two years after commencement of the injection permits, you shall obtain a status on the pressure and review the summary on the performance including analysis by fault on a visit. Is that something Chevron's willing to do?

A Yes.

Q And publicized monitoring where the new well location is covered. It sounds like you already have a very robust monitoring program in place.

A Yes, we do.

Q And then I think I've touched on everything. So it sounds like with the exception of wanting to get some clarity about the actual mechanics of the step-rate test, Chevron is or is willing to comply with all of the conditions in Exhibit 11?

A Yes.

Q Did you review the OCD's pre-hearing statement?

A Yes.

Q Did you see the statement that the Papa Squirrel is located in an area not favored for DMG disposal due to resource potential?

A Yes.

Q Is that something that you agree with based on your own review and based on your team's review?

A No.

Q And why is that?

A So when we look at the -- the review of the resource, I think we look back at some of the historical previous reviews of that, they -- they brought examples that there are things that are more complicated than when you first look at.

Look at the -- if you only look at SWD interactions with production, you're only going to come up with SWD interactions with production. If you only look at potential Wolfcamp to Avalon, as an example, interactions, you're only going to come up with Wolfcamp to Avalon interactions.

And so looking at everything consistently under, you know, a new light of what's going on in the basin, what's produced water issues. We feel it's important to re-look at that and continue to evaluate it as things change over time. That -- that's our view and -- and the big reason why we're doing this pilot program.

Q Did you see the Division statement about Papa Squirrel being between two areas where increased water saturation has been reported?

A Yes.

Q Is that a concern that Mr. Parizek addressed today?

A Yes, I believe so.

Q The final questions I have for you -- well, is there anything that you would like to say before we conclude our time together?

A Yeah, just want to reiterate to -- to the commissioners that we feel this is a very robust data collection program and our pilots. We feel that it will provide a lot of opportunities to learn, not only from -- again, from our perspective, industry perspective, but from the -- from the OCD's perspective as well as it looks at, you know, the -- the important issue around produced water management

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in Southern New Mexico.

Q Were the exhibits that we discussed prepared by you or under your supervision?

A Yes, they were.

MS. BENNETT: At this time I'd like to move the admission of Exhibits 126 to Exhibit 141.

MR. FUGE: Any objection?

MR. TREMAINE: None.

MR. FUGE: Exhibit so rendered.

(Exhibit 126 through Exhibit 141 were marked for identification and admitted into evidence.)

MS. BENNETT: Thank you.

And I pass the witness for any questions.

MR. FUGE: Mr. Tremaine, do you have questions for the witness?

MR. TREMAINE: I have two questions, Mr. Chair.

BY MR. TREMAINE:

Q Mr. Comiskey, thank you for walking through some of your observations on Exhibit 11. Independent of Exhibit 11, your recommendations of the OCD, do you or Chevron feel that DFIT tests should be performed on all proposed DMG wells?

A I think -- we think it's a very important understanding to collect dynamic data on stress in the reservoir properties. Yes.
Q Would Chevron be willing to incorporate that into the recommendation in addition to what we've seen this before in Exhibit 11?
A Yes, I believe so.
Q I want to ask you a follow-up question generally about this stress orientation that you're talking about and the seismicity in slides 135 and 136. One of the Division's concerns and in presentation -- we'll get into that more later or tomorrow -- is areas of uncertainty and knowledge of the geology in the area.
And I would argue that present communication with Chevron today actually corroborates some of that concern that there are certain areas where more data is necessary. When we hear your presentation related to seismicity, I think it's fair to say that you state or implied a relatively high level of confidence that there are not unstable faults in the proposed injection area.
I'm just wondering if you can articulate and help explain, like, what could be seen as kind of a delta in that confidence. Why, when we're talking

about an area with geologic uncertainties, are we relatively certain about the lack of faults or lower risk seismicity?

A So when we think about fault, right, that's -- that's a feature that you can map in 3D. You can connect up those datapoints. It has -- it has an aperture, it has closure. When we think about some of the lineaments or some of the mechanisms that have been discussed have made -- have been conduits to -- to water pool, those are not what we'd call faults.

And so the ability for a lineament to -- to generate an appreciable seismic event, it's -- well, it's very limited. And that's because again, the -- the stress built up in that. How much stress is -- is there, you know, over time, the orientation of those. And so the differentiation between fault and lineament is a key thing.

When we think about faults, we think about, you know, whether it's big, you know, the magnitude 4 quake or the larger earthquakes seen in front of me, those are on things that are rooted, large features that we can map. And my colleague Jason Parizek showed a -- a map of a large fault right through the area. We can see those. We can handle those.

When we think about lineaments or fracture

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system, those are two different things. And so the ability for a fracture system necessary to generate a large earthquake is -- well, it's not applicable.

MR. TREMAINE: Thank you for that.

No further questions. Thank you, Mr. Chair.

MR. FUGE: Ms. Hardy, do you have any questions for the witness?

MS. HARDY: I do not. Thank you.

MR. FUGE: Dr. Ampomah?

DR. AMPOMAH: Yes, sir. I do have a couple.

So let's start from page 126. I will probably skip to 127. So on this particular page, definitely you showed that the Papa Squirrel is within that SRA?

MR. COMISKEY: Yes.

DR. AMPOMAH: But the Severitas 2 State SWD 1 is not in that area?

MR. COMISKEY: Yes.

DR. AMPOMAH: So considering if you look at the deeper zones, where there's a lot of micro-seismic events happening, why would you not consider building this well that's not dealing the SRA rings, they're deeper. You know, why would you not

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consider building that all the way to Devonia because there's no micro-seismic event there?

MR. COMISKEY: Chevron has two Devonian deep SWD wells located very proximal to Severitas 2 SWD 1 already. And I won't speak to -- to economic thresholds on drilling deep wells and the cost and impact. So I -- I won't speak on those, but we are -- we do have two deep disposables right there already.

DR. AMPOMAH: Thank you. Now, you showed a slide where you were comparing a map of seismic events in Texas and in New Mexico.

MR. COMISKEY: Yes.

DR. AMPOMAH: What is New Mexico doing better than Texas?

MR. COMISKEY: I won't -- I won't necessarily speak to better. I think that would be more of an opinion. But I -- I will say the -- the geology in the basin is different.

So if you look -- if I go to slide -- well, if we go to slide 131 or document 131, one of the things to do is there's a lot more water being disposed in Texas than in New Mexico. There's a lot more water coming across the state line from New Mexico into Texas. So there's a lot more disposal.

The likelihood of induced seismicity from -- from disposal operations is -- is I would argue higher.

But also too the geology's different. In that seven part of Culberson County, that's the age of the -- of the Permian Basin roughly. There's a large set of old reverse faults. They extend up.

And some of those are -- are visible on the -- on a foreign figure on slide 135. If you look -- if you look over, you can see near where it -- it says the Apache Fault Zone. Those are deep fault zones. So there's a large set of deep faults that are roughly -- yes, yes.

You see the earthquakes just above it. There's a large set of -- of reverse faults that extend in that part of the basin. And so the -- the hypothesis there, again, when you think about the -- the deposition and the thrust that kind of formed the basin back during the -- the order mission and the Silurian and Devonian time.

Those faults were -- were activated. They're reverse faults. Now they're -- now they're activated normally. And they're oriented in the manner based on focal mechanism data that are roughly parallel to the stress direction. And so that area has a unique set of -- of circumstances. It might not be a big fault.

You have a mechanism, which is deep disposal, and then you have the orientation of the fault is roughly parallel to the stress direction. So you know, combining those ingredients together makes that area very sensitive to -- to perturbation. And we've seen through modeling work and there's been some papers published that modeled on the order of roughly 10 psi change in those deep formations is enough to induce slip.

In Southern New Mexico, we obviously -- there are deep faults. There are earthquakes, but it's a slightly different set of ingredients in Southern New Mexico, so we haven't seen the proliferation. But again, the disposal volumes are quite different between Southern New Mexico and the northern part of the Texas Permian Basin.

DR. AMPOMAH: So in your slide 129, page 129, as we all know, the deep injection is in the one here, but the micro-seismic events is way deeper than that. So based on your expertise, what is really causing that?

MR. COMISKEY: So the -- the faults that are down here that are moving, they extend up into the Silurian/Devonian. We can see them. And so

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they're acting as conduits of water.
A fault isn't all that it was. It -- if you think about -- if you think about the San Andreas fault, we often think about it as one long continuous fault, but we know there's earthquakes in Los Angeles and there's earthquakes in the Bay Area; right? But the whole fault doesn't move.
Very similar here. I mean, think about these faults that are in the basement. The whole fault doesn't move. Only portions of that fault move during a period of time.
And so is injection or pressure actually the pressure. It's not direct fluid contact. It's the pressure. As that pressure goes into those formations and diffuses out, that can create a more lasting change in the reservoir. Can also create a drip pressure, i.e. reducing the effective stress.
And that lead me through to direct transformation into the -- the basement just through the -- through the interval or into some of these faults. Down the fault, coming to a point where the fault is even more critically stressed, inducing slip. And we've seen that recently, where you have a fault that has moved several different times along the transect of that fault.

DR. AMPOMAH: On your page 137, you talked about the framework that industry has a preference. I want to know at what point does NMOCD come see?

MR. COMISKEY: Well, we also have down here, "Seek OCD resolution." But our goal as the -- as the industry -- and again, the -- we will be collaborating and communicating with the OCD through all of this. We're more than willing to be transparent on working with industry. Again, this is an industry problem on produced water management.

And so in vision the OCD could come in at any point. We like to keep the OCD or hope to keep the OCD engaged. But we do recognize that, you know, at some point if there's -- there's scrambling with the other resolution that already is going to agree to the OCD has the ability to -- to implement and remove the permit or act. And we recognize and support that authority.

DR. AMPOMAH: Yeah, because when I look at it, you know, on your lefthand side, if let's say no interference, then that means no action is needed; right? But I don't see where there is a communication to NMOCD about let's say even anything happened.

MR. COMISKEY: So again, I think when

we look at this, this is just a -- this is just kind of a high level, you know, just -- just flow. The whole -- the premise of this is that the stakeholders would be engaged on this. And it can be the stakeholders that are involved in the well, could be a mobile working group, and -- and also the OCD for some process.

DR. AMPOMAH: Let's look at the data that surveillance program. So I want to ask how often are you using poly DFMI to identify natural process?

MR. COMISKEY: I'm -- I'm pretty confident. We've -- we've had good results in using FDMI logs across the Permian to identify open and closed heel fractures. We have a -- we have a very robust in-house technology group and our technology company that -- that's what they do every day that that's what they do every day is look at image logs around the world.

So I -- I feel very confident. We've had a good success of -- of recognizing fracture systems, fracture networks within those concealed, closed, you know, open.

DR. AMPOMAH: So you want to use the spinner someday to identify the --

MR. COMISKEY: Yes.

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DR. AMPOMAH: And is it you will compare with the log data?

MR. COMISKEY: Yes.

DR. AMPOMAH: So which log data are you going to compare that to?

MR. COMISKEY: So when we think about the high -- again, these are -- these are sandstone, so we can look at the transects. My colleague Tom Merrifield noted that.

So we can look at the porosity trends in these sands, depositional geology if you're in a -- you know, if you're looking at a Bouma sequence looking at those upper finding sequences and looking at where the high porosity, thick channeling sands, blocky sands, so we can look at that from the -- the porosity and neutron density.

And they correlate that to permeability that we -- there are -- I would probably defer to my colleague Tom Merrifield on any more detail on that. But it's a pretty standard processing and sands and then relating that to -- to, you know, high clean zones for water.

DR. AMPOMAH: Yeah. For water, that is -- I still feel, just a suggestion, but you might want to still consider recording some of these productive

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loss, like some of these injector zones. It could be easy comparing.

MR. COMISKEY: And -- and to add to that, we do have cork that we have collected in other either disposal wells -- or not disposal wells, but wells we drilled through the DMG to help constrain the models for those pour process. It's not like we don't have any core at all. We do have core to it but.

DR. AMPOMAH: So it's an accident then.

MR. COMISKEY: That's right.

DR. AMPOMAH: Now, so when I look at your program, I see a lot of stunted data collection.

MR. COMISKEY: Yes.

DR. AMPOMAH: Less than our data collection. But I do see you do have the production monitoring.

MR. COMISKEY: Yes.

DR. AMPOMAH: So I want to know he -- I'm just going to recommend that you should consider dynamic modeling, simulation, and also coupled with your mechanics too.

MR. COMISKEY: So we -- we do have that list. We are going to take that. So we're doing -- we are currently doing mechanic worth modeling in this. And so this dynamic data will help feed into

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that mechanic worth model over time.

My colleague Bryce mentioned some of the RTA work. This will help feed that. And so we are -- we do have robust data modeling. My colleague Jason Parizek, he showed some of the modeling work that was done on the -- on the line -- the line frac modeling.

We have -- we do -- again, are -- are expanding upon that modeling work as we get more dynamic data to be able to, you know, constrain the models and be able to push the models further. So we -- we are looking at that in-house as well.

DR. AMPOMAH: Yeah, but you said you do the mechanics. But what about the hydrodynamic? More complex than the one that Kappa will give you and then the fracture and then also the potentially gone?

MR. COMISKEY: So when we think about going to more complicated modeling, I think the limiting factors are the data quality and the data abundance. You -- we can go to a very, very complicated dynamic model, but if the data we have isn't robust enough to support that, the results, I would argue, are -- are fairly ambiguous.

So we've seen a lot of high value and -- and running more simplistic models for the questions you're trying to get after. Think when we take a step back and look at the overall status of just disposal and data collection associated with that. It's very limited.

And so taking a step to collect this data I think is a big step. We hope to continue to progress that. I mean, to more data acquisition than others. Maybe we'll get more -- more complicated modeling efforts. But thinking of the current position we're in right now with just the data we have, I see a lot of value for the more simplistic models and a lot more uncertainty in the more complicated models just because the data we have doesn't necessarily support that.

DR. AMPOMAH: So in regards to the tracer, so based on the earlier analysis, you didn't have control over the other well. Are you saying that you're going to have control over the wells to be able to perform the tracer test?

MR. COMISKEY: Yeah. Yeah, one of the key things is, you know, we start running. We can -- we look at this and we need -- we see the need to run tracers. Obviously, we're going to have the wells, you know, next to us so. And when we execute a tracer program, if you're trying to understand a particular question or understand something, having the, you know, control of the wells nearby to be able to test that is very important.

If you have other -- other operators or companies, trying to get on the same page sometimes can -- can be a challenge. So that's a -- that's a strategic advantage and part of the reasons why we picked these locations.

DR. AMPOMAH: I don't believe I can ask questions related to the Exhibit 11 because they don't talk about it.

MR. FUGE: The witness testified to it. So you can ask questions.

DR. AMPOMAH: So if we can go to that one. And I do have some few questions.

So as we review Chevron's application, my first question is so you can go to OCD isn't it?

MS. BENNETT: Oh, OCD. I'm sorry about that.

DR. AMPOMAH: So the first question that I have is the first one. You know, number one, approved locations outside the identified well productions till deleted by the -- and provided by the -- as an except, so in one of your wells, you are within that area.

MR. COMISKEY: I believe we're actually in that area in both wells.

DR. AMPOMAH: You're in that area in both, yeah. In both wells in that area.

MR. COMISKEY: Yes.

DR. AMPOMAH: So does your communication satisfy the admonition?

MR. COMISKEY: It does not. And -- and again, the reason why we're trying to re-look at this is that, you know, we -- we understand there's concern on this. But generally, drawing a -- a big circle on a map and saying, "Don't go in here anymore" is -- is maybe not the best approach when we think about a long-term strategy of produced water management.

We understand there's risks. That's why we -- we come here today. That's why we're presenting this robust data collection program. That's why we're disseminating it. We think that again having a data-driven pragmatic approach to disposal is probably a better and more advantageous way to understand the risks. So that is why -- that's why they're pushed together.

DR. AMPOMAH: Was Chevron part of that?

MR. COMISKEY: I believe Chevron was part of that, yes. I -- I was not a part of that group. I was not employed at Chevron at the time.

DR. AMPOMAH: So was it more like a general knowledge or is a settled group -- like, yeah, I'll buy them back?

MR. COMISKEY: So I -- I would argue that things change. When this -- when this was put up, there was -- there was good work that was brought forth in my opinion on this.

I think we provided testimony that again if you only look at disposal related interactions with production, you're probably only going to come up with disposal related questions. If you only look at fracture driven interactions or FSIs, you're only going to -- you're only going to come up with that. So looking at everything holistically, is just probably a good approach.

I mean, also too, I would also suggest that in 2015, 2016, 2017, the concern around produced water management was not what it is today. The rise of seismicity has definitely impacted industry. It's created I think a step change in how we need to handle it.

The amount of water that we're handling on a daily basis is -- it's never been worked at before in the history of our industry on this scale.

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And so I think re-looking at all options and how we can -- can manage that is very important. So I think it's a multitude of things.

DR. AMPOMAH: So does that mean that if the commission agrees to Chevron's request, that one needs to be struck down or something?

MR. COMISKEY: I would argue that maybe it's more of a taking a data-driven approach to disposal within -- within the -- the Avalon production area. I think that's the way that Chevron is advocating for this. We -- we aren't advocating for a free for all in disposal. We're -- we're advocating for again a data-driven, pragmatic approach to -- to understanding disposal in -- in the area.

DR. AMPOMAH: So on 2Bm, exclude the lower Brushy Canyon formation from the interval. So I know that you said Chevron was saying it's just going to be different. "We are not going to do any injection there." But it's still part of what you want the canyon for.

MR. COMISKEY: Yes, and I -- I believe we're not drilling -- we're not drilling into the lower Brushy. We're drilling into the upper portion of the Brushy. The Brushy is roughly 1,000 feet thick.

DR. AMPOMAH: So there is a separation?
MR. COMISKEY: Yes. Yes. We're not drilling through the whole Brushy. We're not drilling into the lower Brushy. We're drilling into the top portion, logging it, collecting the data, and then again, as was common early in testimony, it will be sealed off.
DR. AMPOMAH: Now, 3C. You've planned oxidizing. You've planned oxidizing as part of your demolition plans. That's --
MR. COMISKEY: I -- I don't believe it does. I mean, we're committed to -- to adhering to the permit. And we keep making sure that the fluids are complying within the injection interval for the UIC program.
DR. AMPOMAH: So NMOCD is also proposing 4F. So OCD should establish a process to allow the use of existing data imaging in disposal wells as exploration wells, including pressure monitoring. Now, when I looked at -- I need to know definitely you were going to have the pressure measurement. Is it downhole or?
MR. COMISKEY: It's -- we'll have service injection pressure monitoring and also downhole reservoir pressure monitoring. Yes.

DR. AMPOMAH: So do you support that point? Can Chevron agree to that?

MR. COMISKEY: Absolutely. If -- if there are abilities to look at existing DMG disposals for monitoring, absolutely.

DR. AMPOMAH: Thank you, and thanks for you knowledge on micro-seismicity. It was exact.

MR. FUGE: Mr. Bloom?

MR. BLOOM: Yeah, just a couple questions. If we go back to 3C for a second.

Does an acid treatment create new fracture systems?

MR. COMISKEY: No. I mean, the acid treatment we're looking at is mainly on the cleanout side. It's to -- you know, it was common earlier to look at skin, you know. You know, clean up some of the near well bore. Things like -- that's the purpose of the action. Acid injections.

MR. BLOOM: Just wanted to clarify that. Thank you.

I appreciate your analysis on the future proposed seismic monitoring program. I hope that that data is publicly available or that there's some way that the Land Office can access that as you put out the program.

We have -- OCD has its SRA to pick through and does analysis, but the Land Office, we also have an in-house review that we do before we issue any salt water to federal easements. So I don't know that we need all the data dumped on us, but having a system where we can get in and see what you've sent over and be very smart of you to be helpful.

MR. COMISKEY: Absolutely.

MR. BLOOM: Thank you.

MR. COMISKEY: And in the present?

MR. BLOOM: That's it.

MR. FUGE: I just have a couple. I'm on page 137, the sort of notional structure. I think this makes sense as sort of a decision tree and appreciate the notion of, you know, keeping the OCD involved but sort of limiting, you know, direct engagement so, like, we can't sort through it ourselves. So I sort of appreciate that in the structure.

I do have a question about the first one, and more just well, I have two questions. One, how will new producers in the area know about this and other structure? Or do you think that universe is well-defined, that when we issue the approval, the

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universe of producers that might be impacted are going to be already known?

MR. COMISKEY: So obviously, we -- we can only communicate this through the -- the DMG work group, but there's NMOGA. And so that helps a lot. We also reach out in IPAM. So I'm -- I'm engaged in the -- the deep -- the working group that covers that.

And so and then too obviously through -- through our work with Rowena [ph] Group, we would, you know, be happy if -- if we felt like we had available to notify any operators through any of that, we've reached out through our main contacts to make that establishment.

MR. FUGE: That's helpful. Thank you. And then would the potential interference, the sort of producer potential interference and I sort of see some examples of data. It reads to me a little bit kind of the first time I looked at it is, is this a stumbling block? Like we're going to argue about whether there's potential interference?

Or is this is sort of like she suggests that maybe interference either via watercuts or other changes, and then you immediately jump into the green box, which is sort of the intent. They come in with some data that "Hey, we're seeing increased water

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production," you'd go into that sort of resolution process?

MR. COMISKEY: Yes.

MR. FUGE: Just want a clarification in the testimony. I'm on page 138. You talked through a lot of the sort of various data collection surveillance portions of the program. I guess in your sort of affirmative direct testimony, I took the last three as things that might be done. But then in your exchange with Dr. Ampomah, it sounded like those were things that would be done as part of the deployment. Which is it?

MR. COMISKEY: So -- so if we look at -- so tracers -- tracer things that may be run. The reason for it is if we don't -- we're just pumping tracers in the ground, we're not seeing anything, we could pump forever. And there's money.

But downhole gauge and the offset producers, we already have those deployed. Those were already hand monitoring wells, and so those are there. And then production monitoring is something we -- we do continuously. So -- so the bottom two are happening. The tracers are something we -- we may deploy if -- if there's a reason for it. Yes?

MR. FUGE: On page 140, you talked

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about sort of data reporting and other things like that. Just to clarify here kind of in the -- maybe I was just a little confused with sort of the last two. Is there a suggestion that OCD would be getting sort of a distilled version of the dataset that operators were getting, or would y'all be getting the same?

MR. COMISKEY: So and this -- this would be an opportunity we'd love to engage the OCD on. We would like to put all the data in one location. We don't -- we don't want to manage a share point for every operator and every financial stakeholder.

So we would like to provide all the data, interpreted, raw data. We -- we look at this as maybe having quarterly updates on this with OCD, so everybody's looking at the same data. There isn't "you looked at this, I looked at that." And one location, a one-stop shop.

MR. FUGE: And then just to clarify one comment. You don't need to pull it up. But there was one in OCD's Exhibit 11 about sort of a requirement to provide some publicly available seismic -- I think you answered it you do have a robust network but my understanding is the robust network you have is private micro-seismic, which is a little trickier. So

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do you have a position on the public aspect?
MR. COMISKEY: So -- so the agreement that we had with the provider and the companies is that we can provide that. We can provide the -- the locations of our first quakes and exact attitude to OCD. And we -- we have before.
So -- so that is -- again, we also support expanding the New Mexico territory we've discussed as well. But -- but that -- that data, you know, if -- if needed can be provided.
MR. BLOOM: And then I think the last component, and this is just sort of a, you know, conceptual piece. And again, it's a question I asked. I forget of which witness. It may have been you in your first round of testimony.
When I think pilot, there's sort of like a lesson learned component with the data and a firm commitment to sort of report out at an interval. And so I see and it's not sort of reporting out on every kind of triggering event that's there.
But what I'm not seeing in the proposal is a sort of like "Five years out, we will give a rollup like the Commission has seen for certain" acid bath well. I can think of more recently to talk about it as a component. Am I missing that element, or is

it not present?

MR. COMISKEY: It's -- it's probably not present. And we -- that'd be something we'd love to work on if -- if the permits are -- are approved with -- with you and your staff just -- just to work out a plan on designation, we kind of envisioned having regular updates and then -- and then as you mentioned maybe more milestone updates as well.

MR. FUGE: Yeah, I mean, I think at least from where I'm sitting now, I mean, if the Commission were to issue an order with a pilot, I think I would want at least -- just putting out there. Would you be open to if we put in a sort of -- there was a milestone report at some meaningful number of years out where it's going to open a discussion there to incident five, ten, you know, milestones?

MR. COMISKEY: Yes, we would be open to something like that. Sure, UGS.

MR. FUGE: I have no further question. And mindful of --

Ms. Bennett, do you have a?

MS. BENNETT: Yes. May I do two really brief redirects?

MR. FUGE: Yeah. Yep.

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EXAMINATION

BY MS. BENNETT:

Q So on Exhibit 11, Mr. Ampomah asked you a question about whether you fit within or Chevron fits within the 1A because your two locations are within the DMGRA. But as I read this, it says that it's the recommendation for administrative review, not approval, per se. Is that a fair rating of this 1A is limited to administrative applications?

A I believe looking at that that's correct.

Q And you're here before the Commission on a full hearing and not seeking administrative approval of these applications?

A Yes, that's correct.

Q And would you be willing to move forward with hearings to the extent required in the future for other DMG disposal wells that were within the DMGRA?

A Yes, we would.

Q And then Dr. Ampomah also asked you a question about whether the NMOGA DMGRA is sort of like this set in stone, exclusionary -- for lack of a better word -- that the operators sort of acceded to over the years.

And that made me think of the fact that there are multiple operators who were a part of that working group who have supported your projects. So do you know if XTO was part of that original working group?

A I believe they were. Yes.

Q How about Cimarex?

A I believe they were.

Q Mewbourne?

A I believe they were.

Q Chevron?

A Yes, Chevron was.

Q So do you think it's fair to say that there's been an evolution in thinking since 2016 that's shared by more than just Chevron?

A Yes, I believe so.

Q And that evolution in thinking is what you're presenting to the commission at this time?

A Yes.

MS. BENNETT: Thank you. Those are the only redirect questions I had.

MR. FUGE: Are you reserving?

MS. BENNETT: Yes. I would like to reserve with the opportunity to recall Mr. Comiskey as a rebuttal witness if necessary.

MR. FUGE: Well, in light of the time, I think we're at a natural breaking point since

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Chevron, I believe, is finished presenting its witness. So we will resume tomorrow morning at 9 a.m. with OCD's witnesses.

For those listening in, and this was in all of the announcements announcing the meeting, there is a different link for tomorrow morning's meeting. Just go to the agenda, click on it. Just click on the link for Day Two. And we will start promptly at nine.

Thank you.

(Whereupon, the meeting concluded at 4:57 p.m.)

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I, JAMES COGSWELL, the officer before whom the foregoing proceedings were taken, do hereby certify that any witness(es) in the foregoing proceedings, prior to testifying, were duly sworn; that the proceedings were recorded by me and thereafter reduced to typewriting by a qualified transcriptionist; that said digital audio recording of said proceedings are a true and accurate record to the best of my knowledge, skills, and ability; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this was taken; and, further, that I am not a relative or employee of any counsel or attorney employed by the parties hereto, nor financially or otherwise interested in the outcome of this action.

JAMES COGSWELL
Notary Public in and for the
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