STATE OF NEW MEXICO

OIL CONSERVATION COMMISSION

VIDEOCONFERENCE OIL CONSERVATION COMMISSION MEETING/HEARING

DATE: Thursday, September 8, 2022

TIME: 9:02 a.m.

BEFORE: Chair Adrienne Sandoval

LOCATION: Remote Proceeding
Santa Fe, New Mexico 87501

REPORTED BY: Brett Torrence, Notary Public

JOB NO.: 5413759

A P P E A R A N C E S

ON BEHALF OF NEW MEXICO OIL CONSERVATION COMMISSION:

ADRIENNE SANDOVAL, ESQUIRE (by videoconference)
New Mexico Oil Conservation Commission
Energy Minerals and Natural Resources Department
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ALSO PRESENT:

Adam Rankin, Esquire, on behalf of Pinon Midstream, LLC (by videoconference)
Steven Green, Pinon Midstream, LLC (by videoconference)
Dylan Fuge, General Counsel, Energy Minerals Natural Resources (by videoconference)
Greg Bloom, Designee of Commissioner of Public Lands (by videoconference)
Dr. William Ampomah, Designee of the Energy Secretary/Professor, New Mexico Tech (by videoconference)
Christopher Moander, Commission Counsel (by videoconference)
Florene Davidson, Commission Clerk (by videoconference)

A P P E A R A N C E S (Cont'd)

ALSO PRESENT:

Adam Rankin, on behalf of Pinon Midstream, LLC (by videoconference)

Jesse Tremaine, Oil Conservation Commission (by videoconference)

Brett Torrence (by videoconference)

Steven Green, Pinon Midstream, LLC (by videoconference)

Dylan Rose-Coss (by videoconference)

I N D E X

E X H I B I T S

NO.	DESCRIPTION	ID/EVD
Pinon Midstream, LLC:		
Exhibit A	Application	23/114
Exhibit B	Commission Order R-21455-A	23/114
Exhibit D	Application for the Independence AGI #2	52/114
Exhibit E	David White, PowerPoint Presentation	53/114
Exhibit F	Notice Regarding Hearing	110/114
Exhibit G	Affidavit of Publication	112/114

(Exhibits retained by counsel.)

NO.	DESCRIPTION	ID/EVD
Oil Conservation Division:		
Exhibit 1	Dylan Rose-Coss Curriculum Vitae	138/141
Exhibit 2	List of Current AGI wells	145/146

(Exhibits retained by counsel.)

P R O C E E D I N G S

CHAIR SANDOVAL: August 8th at 9:02 a.m. And this is a regularly scheduled meeting of the Oil Conservation Commission.

I'm Adrienne Sandoval, Chair of the Oil Conservation Commission and Director of the Oil Conservation Division.

Would the other two commissioners please introduce themselves for the record?

COMMISSIONER BLOOM: Madam Chair, good morning. My name's Greg Bloom. And I am the designee of the Commissioner of Public Lands.

DR. AMPOMAH: I am Dr. William Ampomah, designee of the Energy Secretary and also professor at New Mexico Tech.

CHAIR SANDOVAL: Also with us is Commission Clerk, Florene Davidson, and Commission Counsel, Chris Moander.

First item is the approval of the Agenda. Is there a motion to adopt the agenda?

COMMISSIONER BLOOM: Madam Chair, I so move.

DR. AMPOMAH: Madam Chair, I second.

CHAIR SANDOVAL: Mr. Moander, would you do a rollcall vote please?

MR. MOANDER: Absolutely, Madam Chair. Commissioner Ampomah?

DR. AMPOMAH: Approved.

MR. MOANDER: Commissioner Bloom?

COMMISSIONER BLOOM: Approve.

MR. MOANDER: Madam Chair?

CHAIR SANDOVAL: Approved.

MR. MOANDER: The motion carries.

CHAIR SANDOVAL: Next item is approval of the August 11, 2022, meeting minutes. Is there a motion to adopt the meeting minutes?

COMMISSIONER BLOOM: Madam Chair, I so move.

DR. AMPOMAH: Madam Chair, I second.

CHAIR SANDOVAL: Mr. Moander, would you do rollcall please?

MR. MOANDER: Yes, Madam Chair. Commissioner, Ampomah?

DR. AMPOMAH: Approved.

MR. MOANDER: Commissioner Bloom?

COMMISSIONER BLOOM: Approve.

MR. MOANDER: Madam Chair?

CHAIR SANDOVAL: Approve.

MR. MOANDER: The motion carries.

CHAIR SANDOVAL: All right. Next item

on the Agenda is an update on Case Number 21872. Application of Titus Oil and Gas Production for approval of production allocation.

And I believe we have Dylan Fuge from the Energy Minerals and Natural Resources Department to provide an update on the status of the MOU between Texas and New Mexico.

MR. FUGE: Good morning, Madam Chair, Commission.

My name's Dylan Fuge. I'm the general counsel at the Energy, Minerals, and Natural Resources Department.

And I can give the Commission the following update on the MOU.

Actually, we ended up calling in an MOA with the Texas Railroad Commission. We were able to successfully conclude negotiations with the Railroad Commission in the last week or so.

The document was fully executed by both parties, last Friday, September 2nd. And we are currently working on, at least on the New Mexico side, some updates, a Notice to Operator, and some announcements, just to communicate the existence of the MOA, and some of the expectations consistent with my prior reports, and this Commission's Order.

The MOA covers allocation of production and the Application of Regulatory -- Variance Regulatory Requirements to cross border facilities.

And to be clear of the type of cross border facilities recovered are cross border facilities with producing intervals and take points in both states from the same wellbore.

And so I'm happy to dive into a little bit more detail if the Commission has questions. But otherwise, that where things stand.

CHAIR SANDOVAL: Are there any questions from the commissioners or counsel? Question counsel or recorder?

MR. MOANDER: I have a question.

CHAIR SANDOVAL: Go ahead.

MR. MOANDER: Mr. Fuge, would it be possible to get a copy of that document sent to me and the commission members? Is that okay?

MR. FUGE: Yes.

MR. MOANDER: Could you do that? Awesome.

MR. FUGE: Absolutely.

MR. MOANDER: I think in order to foster discussion, and I hate to suggest we might want to drag you back to a meeting.

Having the opportunity to review all that, and then me discuss it with the Commission, and then ask you questions, is probably going to be a bit more fruitful of a discussion.

I realize this was all jammed in. So I, by no means, fault you or anything for not having the document out today.

But yeah. I think that might be a good idea, Madam Chair. Is if we have questions, or you know, I can speak with you commissioners individually.

If there are questions, then you can request that Mr. Fuge reappear next month if we want to ask him any.

MR. FUGE: That would be --

MR. MOANDER: Or -- I could --

MR. FUGE: -- that would be perfectly fine with me. Yep.

CHAIR SANDOVAL: I'm muted and just talking to myself.

So general question. I believe it was part of the Order we entered into, jeez, eight months ago, six, eight months ago, that it was required for the Division to provide quarterly updates.

With the MOA being executed, does that need to continue? Or I think that might be completed.

MR. MOANDER: That'll be up to, I think your discretion, Madam Chair. What we could do, is next month, bring this back for review, or revision of that Order.

And then we could -- we would modify the Order and alleviate the burden of -- of the Division to appear quarterly.

CHAIR SANDOVAL: Okay. You're kind of coming in and out a little bit for me on sound. I don't know if I'm the only one.

MR. MOANDER: I think my -- my -- honestly, I think my headset is about to give up the ghost. I noticed some exposed wires this morning I hadn't seen before.

So it -- they've served well for over two years, but the end is neigh. So I apologize for that. I don't have any substitutes readily available.

CHAIR SANDOVAL: All right. So it sounds like maybe, Ms. Davidson, can we plan to go ahead and put the update on the Docket again, next month?

Mr. Fuge will circulate a copy to Mr. Moander, of the MOA, and then we can have any discussion that there may be at that meeting.

And potentially modify the Order to

alleviate the Commission, or the Division having to appear every quarter for an update.

MS. DAVIDSON: Yes.

CHAIR SANDOVAL: Thank you.

MS. DAVIDSON: You're welcome.

CHAIR SANDOVAL: All right. Anything else from Mr. Fuge before we move onto the next Agenda item?

All right. Thank you for any update. All right.

We will move on to Case Number 22977. Which was Application of Pinon Midstream, LLC to Amend Commission Order Number R-21455-A to increase the maximum daily injection rates for an Independence AGI #1 and #2 in Lea County, New Mexico.

All right. Do we have counsel for Pinon and the Division?

MR. RANKIN: Good morning, Madam Chair. May it please the Commission.

Adam Rankin appearing on behalf of the applicant in this case, Pinon Midstream, LLC.

We have two witnesses this morning. And I would like to make a short Opening Statement.

CHAIR SANDOVAL: Okay. Let's do a soundcheck with the Division and then we can move to

Opening Statements.

I think I see Mr. Tremaine. Are you here?

MR. TREMAINE: Good morning, Madam Chair. This is Jesse Tremaine for the Oil Conservation Division.

Thank you for a soundcheck. We are having -- I am having some issues with the computer audio this morning. So I hope you can hear me.

And I am working with the Division's single witness, Mr. Dylan Rose-Coss, to actually get on right now. He is not yet available in the meeting, but I am talking to him offline.

CHAIR SANDOVAL: He looks like he's on the attendee list. And I can move him over -- I just moved him over to a panelist.

MR. TREMAINE: Excellent.

CHAIR SANDOVAL: Mr. Rankin, are your witnesses with you or do I need to move them over to be a panelist?

MR. RANKIN: They are going to be needed to move over to be added as a panelist. They're actually in the room with me. But -- so we're going to dance around the sound and muting issues.

But they also need to be added as

panelists. That would be Mr. Steven Green and Mr. David White.

CHAIR SANDOVAL: I see a Steven. I do not see Mr. White.

COMMISSIONER BLOOM: I see David White on the -- on the screen in grid layout.

CHAIR SANDOVAL: Oh. Okay. Then he was already over. So I think we've got everybody. Thanks Commissioner, Bloom.

All right. I think we've got all of the functional pieces done. Go ahead, Mr. Rankin, and begin your Opening Statement.

OPENING STATEMENT

MR. RANKIN: Thank you very much, Madam Chair. May it please the Commission this morning.

Pinon is seeking an amendment of the existing Commission Order R-21455-A, which would authorize it to inject combined daily volume of up 20 million standard cubic feet per day for its Independence AGI #1 and #2 wells.

The AGI #1, was previously approved by the Commission under the Order I just referenced. And the AGI #2 was separately approved by the Administrative Approval by the Division in SWD Order,

SWD2464.

However, at the time the Division approved that Administrative Order, it did not believe it had authority to grant an injection rate up to 20 million standard cubic feet per day as requested.

Therefore, we file this Application with the Commission to amend the underlying Order.

And the requested increase in volume is necessary to meet the anticipated acid gas disposal needs of the industry upstream and operations in the area.

The requested 20 million standard cubic feet, just -- but for reference, will occupy a volume, approximately 8,200 barrels per day.

Which is significantly less than what the Division usually sees in terms of saltwater disposal wells.

Which could range, generally, when injecting into Devonian, from anywhere from 10,000 barrels per day up to 30 or 40,000 barrels per day or more.

So for comparison, the current volume limitation of 12 million standard cubic feet per day, would occupy approximately 4900 barrels of liquid volume at the reservoir pressure and temperature

conditions in the injection formation.

So it's a relatively modest request for an increase in an injection rate.

The request will allow the Pinon facility, and the injection wells, will help avoid flaring and will prevent waste.

It will also help prevent the release of atmospheric -- into the atmosphere of CO2, will help assure continued stability and smooth operations at the treatment plant.

Today, we will be presenting two witnesses. The first witness is Pinon CEO, Mr. Steven Green.

He'll be introducing the company to the Commission. He will review the company's footprint operations in Southeastern New Mexico.

And he will provide a short background and explanation for why it is the company is requesting the increased injection rate at this time.

And the second witness will be Mr. David White, which he elects. And he's going to provide the technical background necessary for the Commission to make its determination on the request, provide a short history, and to get the new Commission up to date on the prior approvals, and the background

on the facility, the geology, and the operations.

And then he'll give an overview of the modeling that was done and updated to confirm that the proposed injection rates are suitable for the reservoir conditions.

And then he'll also give an update on the fault slip modeling that was done to confirm that there is not an unreasonably increased risk in undue seismicity.

With that, Madam Chair, I would ask that our two witnesses be sworn in.

CHAIR SANDOVAL: Okay. Let's go ahead and let the Division make their Opening Statements and then we'll swear them in before they each start.

Thank you. Mr. Tremaine, do you have any Opening Statements?

MR. TREMAINE: Very briefly, Madam Chair. Good morning commissioners and Madam Chair.

OPENING STATEMENT

MR. TREMAINE: Thank you for this opportunity. The OC entered its appearance in this matter for limited purposes.

The Oil Conservation Division wants to ensure that appropriate safeguards are met should the

Commission amend the underlying Order.

And the Division also wanted to ensure that the Division's technical reviewers -- reviewer, was available to the Commission for any -- to provide some background information about the Division's review of the Application and to be available for any questions from the commissioners.

The Division does not object to the Application after it's had the opportunity to review the final prehearing statements.

And so I do not anticipate any significant concerns with the materials that I expect Pinon to present today. Thank you.

CHAIR SANDOVAL: Okay. Thank you, Mr. Tremaine. All right.

Mr. Rankin, would you like to call your first witness?

MR. RANKIN: Thank you, Madam Chair.

I'd like to call Pinon's first witness, Mr. Steven Green.

UNIDENTIFIED SPEAKER: Madam Chair. Sorry. I hate to interrupt. But did we get everyone sworn in?

CHAIR SANDOVAL: I was going to have him call the witness and then swear him in.

UNIDENTIFIED SPEAKER: Oh. I didn't know if you were going to do -- okay. That's okay, too. Just making sure we didn't skip over that part.

CHAIR SANDOVAL: Okay. Sorry. Go ahead, Mr. Rankin.

MR. RANKIN: Thank you, Madam Chair. We'd like to call our first witness, Mr. Steven Green.

CHAIR SANDOVAL: Thank you. Mr. --

MR. RANKIN: Madam Chair, I guess you can go ahead and swear him. Thank you.

CHAIR SANDOVAL: All right. Mr. Green, can we hear you?

MR. GREEN: Hello. Can you hear me?

CHAIR SANDOVAL: We can. We cannot see you, but we can hear you. Is that possible to be able to see you?

MR. GREEN: Sorry. I didn't start my video.

CHAIR SANDOVAL: Okay. There you are. All right. Mr. Torrence, would you please swear in the witness?

THE REPORTER: Mr. Green, can you please state your name for the record?

MR. GREEN: Steven Green.

THE REPORTER: Thank you very much.

Could you please raise your right hand?

WHEREUPON,

STEVEN GREEN,

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:

THE REPORTER: Thank you very much.

CHAIR SANDOVAL: All right. Go ahead, Mr. Rankin. Thank you.

MR. RANKIN: Thank you, Madam Chair. May I have the ability to share my screen?

CHAIR SANDOVAL: Yes. Give me a second and I'll give you permission. Okay. You should be able to now.

MR. RANKIN: You all see my screen?

CHAIR SANDOVAL: Yes. Yes. This is going to be a little bit small, but.

MR. RANKIN: I will make it bigger.

CHAIR SANDOVAL: Okay.

MR. RANKIN: So that we can see it.

CHAIR SANDOVAL: Thank you.

DIRECT EXAMINATION

BY MR. RANKIN:

Q Mr. Green, will you please state your full name for the record?

A Steven Green.
Q And for whom do you work?
A Pinon Midstream, LLC.
Q How long have you been employed by Pinon Midstream?
CHAIR SANDOVAL: Sorry to interrupt, but it's really hard to hear you. You came across clearer earlier.
THE WITNESS: Yes. Is that better?
CHAIR SANDOVAL: Yes. Substantially.
THE WITNESS: Okay. I've got to -- so I have to turn my volume up. Yeah. I've probably been there for years where --
CHAIR SANDOVAL: Now, we're getting a lot of -- I'm getting a lot of feedback. You're kind of like echoey.
THE WITNESS: Yeah. Once second. I've got my volume audio down. So just give me two minutes.
CHAIR SANDOVAL: No problem.
MR. RANKIN: Sorry, Madam Chair. We're just coordinating our protocol here.
CHAIR SANDOVAL: Okay.
BY MR. RANKIN:
Q So, Mr. Green, for whom do you work?

A Pinion Midstream, LLC.

Q And how long have you been employed by Pinon Midstream?

A We formed in December of 2020. So approximately 1 year and 10 months.

Q Have you had to talk before the Commission before?

A I have not.

Q Could you please provide a short summary of your educational background and relevant work experience?

A Yes. I've got a Bachelor of Science in Mechanical Engineering from Mississippi State University, graduating in 2001.

I entered the Midstream space in 2008. and have pretty substantial experience in working in sour gas assets, including aiming, treating, and H2S to CO2 sequestration.

Q And what is your current position at Pinon?

A I'm currently acting as the CEO.

Q And in that role, what do your duties include?

A Really overseeing the business strategies of -- of the company, for the most part. I've been heavily involved in the technical design and

installation of the facilities.

But basically overseeing all of the day to day operations and -- and controls of the company.

Q And you're appearing as a fact witness, as a non-expert witness today. Correct?

A That's correct.

Q And you will be presenting a technical witness, Mr. David White, following your testimony?

A That's correct. Yes.

Q And you're familiar with the Applications in this case?

A Yes.

Q Is Exhibit A, which was filed with the Commission previously, is that a correct and accurate copy of the Application that was filed?

(Exhibit A was marked for identification.)

A Yes.

Q And are you familiar with the Commission Order R-21455-A that was entered previously?

(Exhibit B was marked for identification.)

A Yes.

Q And Exhibit B is a hard copy of that Commission Order. Correct?

A Yes.

Q And then the names, just so for reference, the names of two AGI wells that we're talking about here are the AGI -- Independence AGI #1 and the Independence AGI #2?

A That's correct.

Q And approximately, where are these wells located?

A They're located in Section 20 of Township 25 South, Range 36 East, in Lea County.

Q And the Independence AGI #1 has been approved. And it has been drilled. And is it currently operating?

A Yes.

Q Okay. And the AGI #2, it's been approved under an Administrative Order. And it's currently being drilled. Is that correct?

A Correct.

Q And Mr. Green, you prepared a presentation today to familiarize the Commission with your company, with Pinon Midstream, it's operations, and it's current footprint.

And then also, it's request to increase the injection rate in both of these wells.

A Correct.

Q And just bear with me, the company, Pinon Midstream, is requesting to increase the injection rate from 12 million standard cubic feet per day to a rate of 20 million standard cubic feet per day in both wells?

A Correct.

Q And what that means is that Pinon could inject a total volume, combined total volume, of 20 million in either one, or both, or wells simultaneously, or one or the other. Any combination. Correct?

A Correct.

Q Let's see. I'm going to go ahead and move my exhibit to the first slide in your presentation.

And hopefully we can all see it better this way. And I'm moving to slide number three, Mr. Green.

Will you just review for the examiners, give us an overview of the company, it's footprint, it's current operations.

And tell us a little bit about how you came to be CEO, and a little bit about the company's background.

A Sure. I'm happy to. To provide the background, the idea of Pinon Midstream started with -- actually with Ameredev.

Ameredev approached us in -- in early 2020 with an issue they were having in the basin of -- of not having a solution for handling both CO2 and H2S.

As they approached us, we started investigating really, you know, were they the only ones in the region and how significant of an issue it was.

And what we found is that the -- the eastern side of -- of the basin here is heavily laden with H2S and CO2.

And given those findings, we -- we'd come up with the idea of Pinon Midstream of just being solely a -- a solution for -- for mitigating CO2 and H2S for the basin.

So, you know, Ameredev really had the need. They brought -- they -- they were looking for expertise that had substantial H2S and CO2 sequestration expertise.

We had a team of engineers that -- that were really, you know, quite a bit of experience in -- in handling such sour gas.

And so in 2020 we formed the company. And hit the ground running immediately putting in facilities for -- for mitigating the issues that Ameredev had.

They had quite a bit of gas shut in because of the amount of CO2 and H2S that -- that they were experiencing within the region.

Pinon was formed with partners. Ameredev, who is primarily just a producer within this region. And we also have a partner in Black Bay Energy Capital that's provided the -- the capital for -- for the company to -- to build out.

As for the management team, we -- we have got a -- about a combined midstream experience of roughly 55 years of well and gas expertise.

Several of us have pretty significant experience in H2S and CO2 handling. Particularly around sulfur recovery in sequestration.

I personally spent the very first few years of my career in -- in a sour gas treating facility where we were -- we were treating gas that was 32 percent H2S on the inlet and up to 6 percent CO2.

So quite -- quite a bit of experience and understanding of the technical aspects of handling such a sour stream, which is very important for the application we're dealing with.

You know, treating natural gas without CO2 and H2S is -- is a very different technology and expertise.

We were fortunate, you know, to have the experience and come in and -- and really, this is pretty second nature in understanding the design criteria for -- for building an asset out with such substantial contaminants.

Kind of moving on to towards the -- the map, kind of provided in the -- in the screen here.

We'll kind of start off with kind of the hub of our facility, which is the -- the green box, which is our Dark Horse Treating Facility.

At this location, is where our two AGIs are located. This is where our two aiming plants are located.

We've got two 400 GPM Aiming Units with a combined inlet treating capacity of 170 million cubic feet a day.

We're going to talk about the gathering side of -- of gathering the sour gas within the region and -- and directing it towards Dark Horse.

If you -- if you look at the blue line that travels from the Dark Horse Facility, all the way down to kind of the maroon box, the White Horse Compressor Station.

This blue line is a 16 inch sour gas pipeline that we kind of use as a gathering header.

We -- we have low pressure pipes that are behind each of our compressor stations that are owned by the producers.

They aggregate their volumes to our centralized compression points. Particularly, the White Horse Compressor Station and the Gila Compressor Station in purple.

And we also have compression at the Dark Horse Facility as well. We -- we then take that gas, pressure it up to roughly 11 to 1200 pounds of pressure.

We have roughly 45,000 horsepower of compression, and AGI compression, available on the system.

And that gathering system directs all the gas up to the Dark Horse Facility. We then treat it. We remove the CO2 and H2S. We inject the CO2 and H2S downhole.

And then the sweet gas that is left out on the -- on the discharge side of our plant, is then redelivered into our Grande Pipeline.

Which is a 20 inch pipeline that traverses around 20 to 22 miles out into the basin where we provide multiple deliveries to multiple gas processors within the region.

As we kind of entered the region, one of the things we heard and listened, you know, from talking with all the producers in this area, is -- is issues of reliability and redundancy were big concerns.

So kind of our -- our focus has really been to solve their problem but provide as much optionality and redundancy as we can in doing so.

One thing that we're -- we're super proud of, given our -- our infancy as a company, and given the complexity of the things we try to do, is our safety track record. We have zero recordable incidents since we started at the facility.

And -- and I'll tell you, as you buildout Greenfield Systems, you're really susceptible to incidents early on, in your company's infancy.

So we've been able to -- to maintain a very perfect track record for safety. It's been a huge component of our focus and a big part of our culture as a company, and -- and how we're growing -- growing ourselves.

Q And so you are currently the operations of the company. You're limited to Lea County. Is that right?

A That is correct.

Q Mr. Green, I'd just like to point out, I

think your video may be turned off.

So if you can turn that back on is possible, but everybody can see you. There you are. There you are. Great.

So let's move onto the next slide, which I think, will give us a little more of a timeline.

A Yeah. This is kind of the -- this really kind of shows a picture of just how quickly we've -- we've progressed in our -- as a company here.

We -- we formed and in 2020, actually December of 2020, and immediately hit the ground running in developing facilities.

We started construction in March of '21. We were online in August of '21. And -- and we had constructed a -- a portion of our Grande 20 inch gathering pipeline.

We had installed our first amine plant, which is a 40 GP -- or 400 GPM Amine Plant. And I commissioned the AGI Independence #1, by August of 2021.

So roughly 8 to 10 months, is -- is the timeframe from when the company was formed, to when were actually, physically in operation.

Shortly thereafter, after commencing operation, we -- we started commissioning of our sour

gas pipeline the Dehondo [ph] 16 inch pipeline. And our White Horse Compressor Station, which was the most southern station on our system.

Giving it another month, we are adding another compressor station for aggregating more production that was coming online in kind of the central corridor of our gathering asset, our Gila System.

And then in December of '21, we added our second amine training service.

Moving into 2022, we extended our 20 inch pipeline further out into the basin, giving us more optionality for redelivery of sweet gas to multiple processors within the region.

And then, kind of moving into June of '22, we actually spudded our second AGI well, and we're anticipating of having that well ready for operations come early October of this year.

One thing I want to point out is -- is the -- the importance of this AGI in that it provides a very large scalable solution to the basin. Which is very critical for the production in this region.

Q Let's talk a little bit about how that looks.

A Yep.

Q And your operation of the AGI to date. On your next slide, review for the Commission, what each of these graphs represent. And give them a thorough review about the operations.

A Sure. Sure. The -- the two graphs on the left are -- are pressure profiles for the subsurface and surface points that we monitor continuously.

And so this data on the left-hand side is -- is all of the data that we've aggregated for 2022.

And the -- the reason that we're showing this is that we're wanting to show the performance of the well as it's performed with varying amounts of -- of disposal for this year.

The trends are very smooth, and very constant, and it'd indicate that the well is performing very well, and much as we've model anticipated, the -- the well to perform.

You'll notice that the -- the purple line is actually the -- the downhole pressure at the bottom of the well. And that -- that reads over to the right-hand side of the graph.

And the blue line is the -- is the surface pressure of the injection, which reads closer to the left-hand side to -- of the graphs. Okay.

And -- and things that we're pointing out is that we've had a couple of issues, or instances, in -- in our operation where we've lost power. Or the downstream markets had issues withing their facilities and shut us in.

And you can see that we had very minor blips in -- in pressures, particularly at the -- in the downhole injection.

You know, you can see we typically operate around 7400 pounds, but as we come off of injection, we -- we lose less than 200 pounds of pressure.

Which indicates that the well is really -- can handle quite a bit more injection capacity, is -- is what we're trying the articulate with -- with these graphs here.

Moving on to the right-hand side, we wanted you guys -- give an idea of -- of what have we done so far this year?

So if -- if you look at the graph on the right-hand side, we've got a chart that shows both in metric tons and in million cubic feet of what we've disposed on and as -- as a per month basis.

The blue chart, or the blue graph here, indicates that amount of CO2 in metric tons disposed of per month.

The -- the yellow chart that's layered in on top is the amount of H2S disposed of.

And the red line, which is paired with the right-hand side of the graph, is the actual million cubic feet of gas or TAG stream that was disposed of in that given month as well.

One of the things you'll notice, is that our production has some dips, as in it's getting lowered as -- in the front -- first quarter and second quarter of the year.

And you can see it's starting to kind of grow outwards since we've been into May.

And what -- what that shows is that the -- the producers in this region, is they come in to produce and drill wells.

They actually have to shut-in existing gas in order to not affect those wells, while they're drilling and completing new wells.

And so what you're seeing here, in February through April, is quite a bit of gas taken offline in preparation of bringing much more gas online.

So right now, we're currently in the ramp. We are seeing gas being added to our system every day.

Now, August looks a little deformed for this map because at the time we pulled this together, I

only had 23 days of data to kind of show.

But if I were to show you all of August and into September, that ramp goes further out to the right.

The -- the matrix on bottom here, just really kind of articulates physical values from the graphs that you can easily kind of see the comparison of a million cubic feet to metric tons of CO2 and H2S that's been disposed.

Q So Mr. Green, looking at that chart, okay, it looks to me like in T-A-G, TAG, is -- means the treated acid gas. Is that correct?

A That's correct.

Q So I was looking at that chart. By the end of August, you're already approaching 4 1/2, close to 5 million standard cubic feet of gas per day.

And your limit currently, is 12 million cubic standard feet of gas per day.

What are your projections for the company in terms of when you're going to start running up against the injection rate capacity?

A Yeah. It's -- that's a great point. And in -- in exactly a year of operation, we've already achieved roughly 50 percent of the capacity of the existing well.

And with current production projections, we're anticipating of -- of being completely full in the well by the end of 2023.

Q I think in your next slide you're going to talk to us a little bit more about those projections, how you've come to them.

And then let the Commission know the timeframes and why you're asking for an increase in the rate now.

So let's move on to the next slide. And if you would, just review for the Examiners -- the Commissioners, each of the elements of this next slide.

So they can understand how you've come to your projections and what the future production area looks like. Go ahead.

A Yep. Will do. So -- so starting off with this slide here, there -- there's a matrix at the top, that we wanted to provide to the Commission, to give you an idea of what does this TAG gas stream capacity equate to from a physical production capacity.

So with our current AGI capacity of 12 million cubic feet a day, that roughly equates to around 260 million cubic feet a day of gas production. All right.

And giving a -- a specific CO2 and H2O -- or H2S composition, equates to roughly 97,000 metric tons of H2S. And a 109,000 metric tons of CO2 annually. All right.

What we are requesting, is -- is an increase in that capacity of 20 -- 20 million cubic feet a day, which would provide us the ability to treat upwards of 430 million cubic feet a day of produced gas in the region.

And you can see the -- the amounts of CO2 and H2S that was sequestered as well.

Moving further down into the -- to -- of the page here, and -- looking towards the graph, Lea -- Lea and Eddy Counties are probably two of the most prolific regions for oil and gas production in the United States.

A substantial amount of growth has occurred and is going to continue to occur over the foreseeable future.

What we know about the basin, is that it is going to continue to need more CO2 and H2S solutions in order to realize production in this area of the basin.

You can kind of see to the graph here, we -- we do quite a bit of research on kind of

understanding the -- the history produced within Lea County.

And as well as trying to kind of articulate what we believe the growth is going to look like for the foreseeable future.

So if you -- if you look at the graph or the chart to the bottom, the -- the blue portion indicates kind of historical data of what gas physically flowing out of just Lea County has looked like up to 2022. And you can see we've reached over two BCF of gas production.

And with the gray line, it indicates the number of completions that have occurred for the history of the region.

And the -- and the yellow indicates the number of rigs that are -- that have been running just in this county.

So you can -- you can articulate the -- the yellow line and the blue line with the right-hand side of the graph.

And the blue and the orange line equate to the left-hand side of the graph for gas production.

What we're seeing past '22 and over the next several years of -- of production for this -- just this one county, within 5 years we're going to add a

BCF of capacity to this region.

And in order for us to be able to do that, we've got to have more solutions for sequestering CO2 and H2S.

If -- if you move, and look towards the right-hand side of the graph, we've -- we're providing kind of well density for wells completed since 2018, upwards of 2022.

And what you see here is that if you move further west into Lea County, and in towards Eddy County, you see a very, very high density of produced gas.

Well, in that region, it doesn't have the CO2 and H2S issues that the eastern half of the region does.

If you were able to zoom in and look at the green nodes close to the Texas border there, you'll notice that it's not near as dense from producing wells within that region.

And the reason is, is that there's been very limited options for mitigating the CO2 and H2S. And primarily, you -- you typically would find a solution for one but not the other.

And what we've been able to do to bring to the region is a -- a solution for both, and one that

is scalable, and that can handle quite a bit of production.

Which we are seeing already. And the projection showed that we're going to be seeing for the near future.

Q And Mr. Green, you're not just getting these projections from crystal balls or looking at data service companies.

You're actually getting feedback from companies, operators upstream, who are required to submit their gas management plans. And have planning in place in advance of their production.

So you're actually getting that communication from these operators directly with the projections for what their development's going to be.

And so you have some idea, 18 to 24 months out or so. Is that correct?

A That -- that's correct. A big portion of our -- of our business is planning with the producers within this region. There's actually a very critical piece to -- to our existence and the producer's ability to produce the gas.

Now, if you -- if you think about this area of the basin, Ameredev was ahead of -- of all the other producers in the region because they had

existing production that was shut in.

And they knew the amounts of CO2 and H2S. Well, a lot of this area is very untouched. Now, the producers in the region are really figuring out what it is that they're dealing with.

And they're looking for solutions and trying to plan for infrastructure that's necessary for them to produce this acreage.

And we're working with producers every day in planning for volumes. In planning for facilities. In planning for added treating facilities as well.

So we've got projections and -- and a need for ample more gas treating to come in the region. As we said, we're going to be full by the end of 2023 with current forecasts.

And there's more gas out there that we can aggregate and treat if given more capacity with our existing AGI well.

With kind of the way that the -- the markets are set right now, it's a minimum of a 12 month expectancy for being able to approve a project and get it online at this point.

So we really need 24 to 18 months of planning to be -- to be safe and assure that we can meet the deadlines the producers are -- are aiming

for.

Q So in this case, the current status of your operations is that you got the Independence AGI 1 currently injecting and disposing of approximately 4 1/2 or 5 million standard cubic feet per day.

With projections that you're going to max out that capacity in the next 12 months, knowing that you're going to need another 12 to 18 months from today, for planning purposes, to get the infrastructure and capacity in place to meet future demand.

So in short, I guess, Mr. Green, that's the reason why you're before the Commission right now, while the AGI #2 is currently being drilled.

You're already asking for that increase in capacity in order to meet that demand?

A At this time. That's correct. It's -- it's -- we can't go out, and contract, and help plan unless we have the capacity available to us.

Q Well, let's just move to your last slide and give the Commission an overview of the location.

And just review for them what this is and what we're looking at here in this next slide.

A Yeah. So -- so we're looking at a view of -- of the Dark Horse Treating Facility, and we're

actually looking from the west east. So back over towards the horizons is the -- is the town of Jal.

All right. So if you look over to the left-hand side of -- of the screen here, this is the Independence AGI #1. And it's been in service since August of 2021.

You can see there's a rig onsite as we're currently drilling our second AGI well that was spouted in June of this year.

And we're currently around 16,000 feet is -- is where we're located. So roughly about another 2,000 feet of drilling remaining, which we're anticipating to be complete within the next two weeks or less.

Q And that's under your -- under the current Order you guys are required to have the second redundant well completed the first part of November. Is that right?

A That's correct. And we're on pace to be ready for operation come October.

MR. RANKIN: With that, Madam Chair, I have no further questions or Mr. Green. And will pass him to the Division and the Commission for questioning.

CHAIR SANDOVAL: Thank you.

Mr. Tremaine, do you have any questions for the witness?

MR. TREMAINE: I do not have any questions for the witness. Thank you.

CHAIR SANDOVAL: Thanks. Commissioner next.

COMMISSIONER BLOOM: Madam Chair, I have no questions.

CHAIR SANDOVAL: Commissioner Ampomah?

DR. AMPOMAH: No. There are no questions. No questions at this time.

CHAIR SANDOVAL: Okay. I have a couple of questions.

Just generally, can you -- so there are -- let's see, a lot of requirements within the Order that you were issued. For example, let's see.

You're supposed to send in reports to the OCD. There were some quarterly pieces.

Can you just affirm that you have complied with all of those requirements that are currently within your Order?

THE WITNESS: We -- we have. Yes. And as a matter of fact, if you -- if you look at one of the slides, it shows some of the data that we've reported to the Commission.

CHAIR SANDOVAL: Okay. And prior to operation of AGI #2, are you submitting a modification to your H2S Contingency Plan, or was that already in your H2S Contingency Plan?

THE WITNESS: I believe it's already included in our H2S Contingency Plan. But I need to go back and verify that.

CHAIR SANDOVAL: Okay. Yeah. I think there was a requirement 8(a) regarding the H2S Contingency Plan just -- I'm sure you -- take note of that.

THE WITNESS: Yeah. I'll take note. We'll -- we'll provide an answer.

CHAIR SANDOVAL: I guess, when this well was originally permitted, so when you submitted the Application, what's been the change between the original ask of 12 and the 20?

Or why did you originally ask for 12 and not 20?

THE WITNESS: Well, the -- the original 12 was -- was very early in the understanding of what -- what are we solving for in the basin? So the original 12 was actually asked by a producer and Ameredev.

And -- and mind you, they started the

permitting process over 2 years in advance trying to solve their own problem.

Now, the thing that Ameredev understood is that they didn't have the technical expertise to understand and -- and really operate and build out.

But they knew they needed a scalable solution for the amount of CO2 and H2S they had. So when they stepped into this, their -- their goal was solving their own problem.

Well, when we got involved, the permit was already provided for the 12 million cubic feet a day.

And so during that time as we're solving Ameredev's issues, we're out looking for third parties and other producers in the region that we know are having the same issue.

And as we've started aggregating more volume, and we do have more producers than just Ameredev delivering into the system.

And we are disposing of their CO2 and H2S, we -- we quickly understood that we were going to outgrow what we had. And that's what we're trying to solve for today.

CHAIR SANDOVAL: Okay. And just to confirm, you're asking for 20 total between the two

wells.

THE WITNESS: Yes.

CHAIR SANDOVAL: So you will never be injecting more than 20 total between the two?

THE WITNESS: That's correct.

CHAIR SANDOVAL: Okay. Are both of these wells constructed in a manner that you think they can handle 20 as opposed to 12?

THE WITNESS: Yeah. Our technical witness, David White's going to give you the details associated with it.

CHAIR SANDOVAL: Okay.

THE WITNESS: With everything we reviewed, it -- it is. Yes, ma'am.

CHAIR SANDOVAL: And then I think Mr. Rankin hit on this briefly, but there is a requirement in the original Order. I think it was -- let's see.

I have -- I think you have to begin injection within 24 months after the original Order. The original Order was November 4th of 2020. I think you, in your presentation, show mid-October.

I am familiar with how construction deadlines can go. Are you confident that you will be able to meet that 24 month deadline?

THE WITNESS: Yes. Very confident.

CHAIR SANDOVAL: Okay.

THE WITNESS: We've -- we've less than 2,000 feet remaining of drilling remaining.

So we're really kind of through the more difficult parts of -- of the drilling process right now. So we're -- we're very confident that we'll be ahead of schedule for November 4th.

CHAIR SANDOVAL: Okay. I think I have one more question. Oh.

This Order also requires that you install a seismic station, or a seismic monitoring station. Have you done that?

THE WITNESS: Yes. We have. And it is currently monitoring and communicating with the State where they can see that data real-time.

CHAIR SANDOVAL: Okay. Great. Thank you. That was my last question.

Mr. Rankin, do you have any follow-up?

MR. RANKIN: Just one. Madam Chair, I appreciate it.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q Mr. Green, if there is an issue with getting the well completed within the timeframes required

under the Order, the Order also provides for the Division, in its sole discretion, to grant an extension of up to 6 months.

And if that's needed, will Pinon reach out to the Division, and notify them that you need a short extension in order to complete the well, and get operations up?

A Absolutely.

MR. RANKIN: All right. Madam Chair, no further questions from me. And ask that Mr. Green be dismissed unless you have a follow-up.

CHAIR SANDOVAL: Thank you. Thanks, Mr. Green. I think you can be dismissed.

THE WITNESS: Thank you.

MR. RANKIN: Thank you, Madam Chair.

CHAIR SANDOVAL: Mr. Rankin, call your next witness.

MR. RANKIN: Yeah. With that, we'll call our next witness, Mr. Steven -- I'm sorry. Mr. David White.

CHAIR SANDOVAL: Alright. Mr. White, let's make sure we can hear you.

MR. WHITE: Yes. Can you hear me?

CHAIR SANDOVAL: There's a little bit of echo, but not terrible.

MR. WHITE: Yeah. Yeah. We're coordinating our mute strategies.

CHAIR SANDOVAL: Mr. Torrence, would you please swear the witness in?

THE REPORTER: Hi. Mr. White, could you please state your name for the record.

MR. WHITE: David White.

THE REPORTER: Thank you. Could you please raise your right hand?

WHEREUPON,

DAVID WHITE,

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:

THE REPORTER: Thank you.

CHAIR SANDOVAL: Go ahead and proceed, Mr. Rankin.

DIRECT EXAMINATION

BY MR. RANKIN:

Q Thank you. Mr. White, will you please state your full name for the record?

A David Allen White.

Q By whom are -- virtual connectivity interruption --

A Geolex, Incorporated.

Q Have you previously testified before the -- virtual connectivity interruption --

A I have not.

Q And were you -- qualified as an expert in petroleum geology, seismic interpretation, and fault slip probability modeling?

And were those credentials accepted and made in a manner -- virtual connectivity interruption --

A Yes. And yes. They were.

Q And did you contribute to the analysis according to CONOA, the Application that was filed and approved administratively, for the Independence AGI #2, and is marked as Exhibit D in the hearing packet?

(Exhibit D was marked for identification.)

A Yes.

Q Okay. And will your testimony and opinions, that you provide today, evaluate and address the basis for Pinon's requested increase in injection rates in both AGI #1 and #2 wells to a combined total of 20 million standard cubic feet per day?

A Yes.

Q And will you also address the potential for induced seismicity as a result of that injection?

A Yes.

Q Did you prepare a PowerPoint presentation today that will review your analysis, conclusions, and opinions on those topics?

A Yes. I did.

Q Okay. And you're prepared to review those with the Commission right now?

A I am.

Q Then with no further ado, I'm going to set up your presentation so that we can all see.

And Mr. White, has this been marked as Exhibit E in the exhibit packet?

(Exhibit E was marked for identification.)

A Yes.

Q Okay. And I will put this on the screen so you can see it. And we'll start walking through.

Mr. White, will you just briefly summarize what it is that the Application requests? And then just walk through the exhibits.

And if I have any questions, or would like to clarify anything, I may briefly interrupt you.

But otherwise, Mr. White, please just review and I'll advance the slides as you direct.

A Sounds great. And -- and yeah. Hopefully,

some of this introduction will be a little bit of a reiteration of things that have been discussed.

But in terms of Pinon's request, Pinon is seeking amendment of the existing Commission Order R-21455-A to authorize a combined or shared daily injection volume limitation for the AGI #1, are the Independence AGI #1 and #2 wells, up to 20 million standard cubic feet per day.

And as Mr. Green had previously described, you know, meeting the anticipated acid gas disposal needs of oil and gas operators, and production in this area, is -- is kind of the -- the justification for this volume request.

As Mr. Rankin described in his Opening Statement, this request -- when this 20 million standard cubic feet per day volume under reservoir temperature and pressure condition, which have been confirmed through drilling and completion of the AGI #1 Well via direct measurement of baseline conditions, would reflect an approximate 8200 barrels per day being injected into the reservoir.

And as the Commission and the Division are likely aware, is significantly less than typical SWD disposal operations.

The current permit limitations, for another

comparison, the current limitation of 12 million standard cubic feet per day would occupy about 4900 barrels per day at reservoir conditions.

And in utilization of this, of aiming treatment in AGI Wells at the Pinon Facility, are really critical components, as -- as they had been selected as the primary handling methods of acid gas at this facility.

And they really have become a preferred method for that purpose, as you know, they're really offered the opportunity to avoid, or minimize flaring, and prevent waste.

And they -- they prevent the atmospheric release of CO2, which you know, some other gas handling methods, such as sulfur recovery units, you know, don't -- you know, in those applications, CO2 has typically been vented, and historically been vented to the atmosphere.

In making their request, you know, in accordance with the requirements of the original Order, Pinon had filed in November of 2021, the Form C-108 Injection Permit Application for the redundant Independence AGI #2 well.

And the materials that we will be presenting today with respect to addressing the feasibility of

this request were also included in that original redundant well Application.

Which was submitted to the Agency late last year in accordance with the -- the Commission's timeline for the redundant well Application.

So and if I can give kind of a brief introduction of how the remaining slides are going to go, you know, in -- in past acid gas injection well applications, you know, a complete presentation of all the requirements of the C-108 Application are --

CHAIR SANDOVAL: Sorry to interrupt.

MR. WHITE: -- are included in this presentation. But seeing as how for this particular case, both the AGI #1 well and AGI #2 well have been authorized for injection.

The -- the main meat of this presentation is going to be two-fold. First, providing a general background of the project. The location of the project. The designs of the wells. And the local geology.

And then move to focus on tasks more specifically, or items more specifically related to the justification of the amendment to the volume.

So we'll begin just with the background information to make sure everybody is aware of some of

the basic characteristics of the project. The Pinon Dark Horse Gas Treatment Facility, which -- with which Mr. Green described --

MR. MOANDER: Mr. White, I hate to interrupt you.

THE WITNESS: -- is located approximately 6 miles west of Jal, New Mexico.

MR. MOANDER: Mr. White, can we --

THE WITNESS: That location of the service facility and the location of the --

MR. MOANDER: Am I not being heard?

THE WITNESS: -- AGI wells, are shown on this map, section 20.

MR. MOANDER: Hello --

THE WITNESS: The Independence AGI #1 well --

MR. MOANDER: Hello, Mr. White, can you --

THE WITNESS: - as Mr. Green described, was completed and brought into service late August of 2021, and it was drilled as a --

MR. MOANDER: Can we pause this? Can everyone hear me? Can anyone hear me?

THE REPORTER: Yes.

THE WITNESS: The Independence AGI #2

well --

CHAIR SANDOVAL: Yes.

MR. MOANDER: Okay.

THE WITNESS: -- also shown at this facility location, are determined --

MR. MOANDER: Okay. So it sounds like -- in trouble here.

THE WITNESS: -- by the two, are the red injection well icon on the map is being constructed as a deviated well.

MR. MOANDER: Madam Chair, you might interrupt him again.

CHAIR SANDOVAL: Mr. White, or Mr. Rankin, can you hears us?

MR. RANKIN: Yes.

CHAIR SANDOVAL: Can you guys hear us?

THE WITNESS: Yes.

MR. MOANDER: Okay. Let's take a second here 'cause I think we're having some technical problems. And not just -- it's not just you, Mr. White. I think there's some other stuff going.

THE WITNESS: Okay.

MR. MOANDER: Madam Chair, what would you like to do?

Do you want to have everyone log in

again or something? Because it looks like we're having both audio and visual issues?

CHAIR SANDOVAL: Mine has gotten better now. Was he cutting out -- was Mr. White cutting out for everybody else or was it just for me?

MR. MOANDER: I did not have an issue after he started his testimony.

DR. AMPOMAH: Yeah. I'm good from my end. I heard it clearly. Yeah.

CHAIR SANDOVAL: Okay. I was having some issues. But you seem to be okay now. So I think let's just proceed.

MR. MOANDER: Okay. I'm going to turn my camera off too to see if that helps. So I'm not drawing a --

CHAIR SANDOVAL: I did the same. All right. Thank you. Go ahead.

THE WITNESS: Okay. Sure. Thank you. Thank you, guys.

Kicking back off. The Independence AGI #2, also approved through -- through the administrative process as Mr. Green had described, is currently being drilled.

And -- and on target for completion, or -- or for the completion of drilling activities

within the next couple of weeks.

In the map shown, we see the surface location for the AGI #2, as well as the bottom hole location, roughly south, southeast of -- of the Dark Horse Facility.

The project area, the AGI well surface locations, and the -- the AGI #2 bottom hole location, all stay within the western half of section 20, and that surface is owned wholly by Pinon Midstream.

So if we can move to the next slide. And some of this has -- has been discussed.

But in this slide, I'm just wanting to briefly discuss the permitting timeline, and the facility construction timeline, in kind of an organized fashion so everyone can see it.

As we previously mentioned, the Pinon Midstream Treatment Plant was constructed and put into service in late 2021.

The facility again, specifically designed to utilize amine treatment and acid gas injection wells as their method for handling H2S and carbon dioxide associated with natural gas production and treatment operations.

And the Independence AGI #1, which is currently in service, and -- and demonstrating a, you

know, well behaved performance record, was originally authorized by Commission as a UIC Class II AGI Well in November of 2020.

And was brought into service coincident with the completion and start-up of the treatment facility itself.

That original Order, as we've -- we've discussed, has authorized that initial AGI Well to inject up to 12 million standard cubic feet per day. At a maximum allowable surface injection pressure of 4,779 psi.

And as part of the original Order, in the -- one of -- one special condition required, construction and a specific timeline for bringing into service, a redundant AGI Well.

Which while required via the Commission Order, has always been the -- the plan for Pinon to have a redundant injection well system just because it is the primary handling method for acid gas on the site.

And with that motivation, Pinon took steps to begin and meet Commission deadlines for submittal of the second AGI Well Application, the Independence AGI #2.

Within the Commission required

timeline, that application was submitted to the Oil Conservation Division for administrative and technical review on November 4th.

And as part of that Application, the request that we're discussing today to increase the rate, the daily injection limitation, to 20 million standard cubic feet, was made as Pinon was, at that time, better aware of the larger disposal needs of the area.

Despite those materials being included in that Application, and the approval of the redundant well Application on March 31st of 2021, the Division had made the determination that that revision or amendment to the volume limitation could not be authorized via the administrative process.

And you know, we've -- we've discussed about how critical the AGI System is for Pinon's operations, but in general, there's -- there's reasoning that -- that this handling method has kind of become a preferred method for gas treatment and gas processing operations.

In that, you know, AGI wells, and -- and this method, provide the opportunity for a substantial amount of greenhouse gases to be sequestered.

Which, with other options, chemical scavenging, and sulfur reduction, traditionally, has been vented to the atmosphere, which ultimately leads to, you know, the AGI projects and systems, increase the operational stability of plans, especially when redundant AGI well systems are in place.

So that overall, it reduces waste and air emissions, both on -- from flaring on the facility sites, as well as in the field, with that increased operational stability.

And as proposed, Pinon's, and the forecasts for development in the area, the proposed 20 million standard cubic feet per day limitation would -- would allow Pinon to be able to meet the needs of those operators.

And as we see in the last bullet point. When taken on a per day basis at these proposed injection volumes, there's a significant amount of CO2 and H2S that is sequestered.

Now, to remain compliant, even though the C-10 -- C-108 Application that was submitted and approved by the Division, even though it was unable to -- to make any amendment to the allowable injection volumes, you know, the redundant facility is still very important to Pinon's operations.

And as such, they had continued in their effort, to drill and complete that approved well.

As previously discussed, this -- the AGI #2 well was spudded in mid-2022, and -- and currently, is fully on track to meet all of the Commission's deadlines for completion and then service that were described in -- in the original commissioned Order.

Okay. So moving on a little bit from, kind of the permitting history and the approval history, I want to take a few -- I'll take a few slides to discuss the design of the AGI well.

And -- and in this slide, I'm showing a brief schematic of the AGI #2 well as -- as it was proposed and as it's being constructed.

And while this is the schematic that I'm showing, the ultimate design, and design standards, are in accordance with -- with those that were implemented for the AGI #1 well.

Similar to that well, the -- the redundant well is -- is -- incorporates all AGI best practices, as well as specific input from the NMOCD technical staff that was communicated during the application process of the AGI #1 well.

This ultimately resulted in a five-string casing design that allows for individual isolation of the shallow Salado Salt section. And the specific isolation of the Capitan Reef Formation through use of external casing packers and some diverter tools.

For both wells, critically intervals of casing and tubing, such as the base of the well, where lower well components are, where water may be more likely to be present, are specifically designed of -- of materials rated for acid gas service.

Specifically, the use of Inconel 925 and G3 Nickle Alloy corrosion-resistant grade casing. And you can see those being utilized in the well schematic in the lower most interval.

In addition, the AGI #2, as well as the AGI #1 well, had been designed, and utilized downhole monitoring equipment and safety equipment, with a subsurface safety valve.

Typically being installed about 250 feet below the surface, which allows for one, a downhole isolation point that can be integrated into the plant system and is.

And also, just provides protection against any backflow of material out of the wellbore.

Both wells are also equipped with downhole pressure, and temperature sensors that are installed immediately overlying the permanent injection packer and provide real-time pressure and temperature conditions along that -- at that depth interval.

All of the safety equipment and monitoring equipment are also constructed of Inconel 95 [sic] or equivalent materials that are fully rated for acid gas injection service.

And in this slide, we'll take kind of a -- a more diagrammatic look at a two-well AGI system as the -- the you know, for the current Pinon operations.

The acid gas stream is approximately 70 percent CO2 and 30 percent H2S. And to kind of call back to Commissioner Sandoval's question about the H2S Contingency Plan, that ratio of gas is -- is in agreement with the current plan.

And you know, prior to any injection operations at the elevated rate, that H2S Plan would be fully updated and approved to be reflective of those operations.

But starting from kind of taking a look at the diagram again. And starting kind of from the

top right.

For the acid gas injection system, coming off of the amine treatment, the stream of CO2 and H2S, is transmitted to -- or from the amine system to surface compression -- or to a surface compression facility at the well site.

Where it is then compressed to approximately 1500 to 2500 psi and then transmitted to the AGI wells via corrosion resistant pipelines that are equipped with automatic safety valves. Again, to provide many isolation points and to prevent backflow of materials.

The gas is transmitted to the injection trees, which are specifically designed -- they're specifically constructed dry acid gas injection trees, which like many other components in this system, are made of appropriate corrosion resistant materials.

Moving down the wellbores of these two diagrams, we see the placement and annotation for the downhole subsurface safety valve.

Which is exceptionally useful in the event of some emergency, or something that may limit the wellhead's ability to contain gas.

You've got valves upstream of that. And valves downstream of that that are very -- they

can allow for pretty specific isolation of that system.

At the lower portions of the well, we see annotated, the permanent injection packer and the placement of the downhole pressure and temperature gauges that provide real-time monitoring of the base of the well conditions.

And while it's not pointed out, or described in this slide, I'd also like to give you -- describe a little bit, the complete picture of monitoring that goes with the AGI wells that are constructed at the Pinon Facility.

In addition to the continuous monitoring of downhole pressure and temperature conditions, the -- there is also continuous monitoring of surface injection pressure, surface injection temperature, surface annular pressure conditions, and gas flow rates.

These are all communicated to the plant control room in real-time, and the combination of these real-time data sources, ultimately allow for the very rapid identification of any issues in the system.

Whether it's, you know, an integrity loss in -- in the tubing, or things like that. Those -- those sensors really allow for really rapid

identification of those issues.

And with a two-well system, you can -- from those -- those indications, make appropriate changes in your operation.

And here we have just kind of a another look at the project area. More specifically focusing in on its location relative to the nearby city of Jal.

As we discussed previously, the facility is constructed on -- on lands wholly owned by Pinon. Specifically, the west half of Section 20. And it's approximately 6 miles from Jal, New Mexico.

And then in the last point of this slide, I just include the specific coordinates for the surface locations of each AGI well.

Moving on to give a little bit of the background of the geology of the area, in the top panel, Panel A, we have kind of a generalized map showing the major areas of the Permian Basin.

And in the bottom panel, we kind of see a cross-sectional view of -- of the Permian Basin, obviously seeing the significant depths that are reached in the Delaware Basin side of things versus the Midland Basin.

In -- for the Independence AGI #1 wells, and the Pinon Facility, those -- those

operations are -- are located in the eastern margin of the Delaware Basin. You can see in the map, the annotated location of -- of those facilities and wells.

In this area, surface deposits are typically aeolian and alluvial with some local exposure of Triassic red beds. And -- and underlying the surface location, are approximately 9,000 feet of Permian strata, which overlie 8,000 feet of older Paleozoic strata.

And we'll take a -- a more specific look in the next couple of slides at what overlies and underlies the injection zone and -- and its -- their relationship to production in the area and things like that.

But within the area, there's excellent coverage of the you know, the -- the Regional Woodford Shale. Which is a well demonstrated and -- and regional caprock in this area that provides the -- the containment for injected fluids into the -- the reservoir that both of these wells target.

In this area specifically, the Woodford Shale is -- is approximately 300 feet thick. So quite a good thickness of -- of that well demonstrated caprock at the Pinon location.

Both wells target what is often referred to as the Siluro-Devonian, which is inclusive of the Devonian, Wristen, and Fusselman formation strata.

Which are common targets for disposal operations for -- for many SWDs, AGI wells, and -- and has a well demonstrated history of -- of being able -- being productive receptors of injection fluids.

In the area, being near the eastern margin of the Delaware Basin, there are instances of normal faulting that typically are oriented, or trend parallel, to the north, northwesterly trend of the Central Basin platform.

And we'll take a look at those in a little bit more detail in the -- in the slides to come.

Here is just another kind of generalized stratigraphic correlation for the Permian Basin. A lot of the -- the regions of the Permian Basin that were represented in the previous slides map, are -- are included and described in this slide.

The highlighted section in the slide shows the Delaware Basin stratigraphy. And obviously highlighted because as the area of the Pinon Project

and facilities and within those strata, we have annotated the formations in which historic, or active production has occurred.

Not necessarily widespread, but -- but within a reasonable distance from the locations that those are the -- the formations, which is -- had some history of production.

So before you -- before you advance, and we can take note of this a little bit more in more detail when we get to the, you know, the data collected from drilling the Independence AGI 1.

But ultimately there's a significant vertical package of geologic strata that separate the approved Siluro-Devonian injection zone from overlying producing zones.

And here, diving right into that, is kind of, in this slide we're reporting the formation tops that were encountered for drilling the Independence AGI #1 well.

And we see again that looking at the most -- or the right portion of -- of the stratigraphic, or of the well log shown there, we see that we've got, you know, between the top of the approved injection zone, where the top of the blue bar marked "Injection Interval" is, and kind of the -- the

interval of potential production in the straw anitocca [ph], and marrow section.

We've got well over a thousand feet of separation between that, which kind of illustrates the -- the actual data collected and confirms kind of a -- the -- the information shown on the previous slide.

Taking another look at -- at some of the background geology info of the area, in this slide, we show a structure contour map generated from sub-C elevations of the top of the Devonian.

So it's essentially a structured contour map that illustrates the -- the shape, the -- the dip angles of the top of the Devonian Reservoir there.

And we can see the AGI #1 well location annotated at the -- very proximal to -- or at the A point in the A to A prime cross-section trendline, which we'll discuss in -- in the next slide.

The AGI #2 being the second node of that trendline. And then finally, another nearby Siluro-Devonian penetration marking the A prime location in that trendline.

But we see the AGI 1 and the Pinon Project area being located downdip of a local

structural high in the area. And kind of bounded with larger fault features to the north and to the east.

And if we can move onto the next slide, we'll take a look at the cross-section that that trendline is -- is illustrating.

So we see that cross-section in -- in the figure to the right here. And one thing, it -- it certainly illustrates the -- the porosity of -- of well-logged data in the area.

Which from an injection well operation standpoint, you know, it equates to fewer penetrations and fewer potential issues of gas migrating out the reservoir. But it certainly make investigating the deep subsurface a little more challenging to have less control.

And so for both the Independence AGI #2 Application, the original AGI #1 Application, and those projects, analysis and evaluation of 3D seismic data covering the area was an absolute necessity to make sure that productive intervals of the reservoir where injection operations can be maintained safely, is identified.

So we see in -- in the well data that are available and are inclusive of well -- of data collected from drilling and completing the AGI #1, we

can see the porosity profile, and certainly see the local coverage of that thick interval of Woodford Shale, which behaves as the caprock material, or the primary containment layer in this area.

As -- as secondary containment, you know, this Woodford Shale is also over let -- overlaying and -- and these data were confirmed by drilling the Independence AGI #1 and collecting sidewalk bore data.

But overlying the Woodford Shale, is the -- the overlying 950 feet -- approximately 950 feet of Mississippi in carbonates of the Osage formation are also characteristically very low -- very low porosity in permeability units.

So they could provide additional protection to -- to -- in confidence, that the gases injected in this area, are going to be contained within the target.

MR. RANKIN: Madam Chair, are we done with the geology review?

THE WITNESS: Yeah.

MR. RANKIN: Madam Chair, having completed the background section here on the geology and history, I want to check to make sure the -- about being an hour in, I want to make sure the court

reporter is doing okay.

And if we want to take a break, we could take a quick break now. Or continue into the modeling, which would be the next topic of testimony.

CHAIR SANDOVAL: Okay. Why don't we take a 10 minute break and come back at 10:40?

MR. RANKIN: Take a break now till 10:40.

CHAIR SANDOVAL: Can you hear me?

THE REPORTER: Yes.

DR. AMPOMAH: Yes.

CHAIR SANDOVAL: Okay. All right. We'll be back at 10:40.

THE REPORTER: Off the record now at 10:30.

(Off the record.)

THE REPORTER: Back on the record at 10:40.

MR. WHITE: Okay. So now that we've kind of covered a lot of the background information on the project and the local geology, I want to move into the additional work that's been completed in advance of the submission of the original AGI #2 C-108 Application.

And there we go. Nope. Nope. Nope.

Eighteen. Okay.

And so I want to talk about the additional work that's been done that more specifically focuses on the justification and the request to amend the allowable volume to 20 million per day.

And -- and this additional work is -- has really -- revolves around two questions.

The first being, is the reservoir -- in the injection reservoir, in our understanding of it, currently suitable to support this injection rate being requested.

And you know, what impacts will that have on the reservoir? What will the result in plume look like?

And then also, what does -- what are the risks of induced seismic events in response to this change in the allowable injection volume?

And -- and so this work really started with first updating the existing geologic simulation model that was presented in hearing for the AGI #1.

To be inclusive of not only well log data, but the results of reservoir testing that was performed during the drilling and completion of the AGI #1.

And to revise that model to -- to better reflect our understanding of the subsurface now, and also build in, and consider the AGI #2, and it's injection contributions into the reservoir.

With the ultimate goal of trying to understand, after 30 years, what does the result in acid gas plume look like in terms of its dimensions?

What are the concentrations of acid gas within the reservoir when these wells are operated as proposed?

And then finally, just re-evaluation of the slip probability and the risk for induced seismicity in response to operation at 20 million standard cubic feet per day for the two wells. Or to be clear, shared by the two wells.

And so we have a little bit more background in this, in that in our evaluation of both the original AGI #1 well, and our evaluation and development of the permit application for the AGI #2 well, in both of those instances, 3D seismic data were reviewed, in order to site locations.

And of course, were revisited and re-evaluated, at the time of permitting and developing the permit for the AGI #2 well.

In this map, we showed the faults that

were identified in the area, and to confirm, even though re-evaluation during the time of AGI #2, our interpretation of those subsurface features remains the same.

So we have -- we've identified eight faults that typically trend in line with the -- the north-northwesterly trend of the central basin platform with a few smaller features that are semi-perpendicular to those.

As we described previously in the -- the Devonian -- in the slide where I discuss the Devonian Structure Map, the nearest faults to the location are the large north-south feature to the east of the well locations, and then the northern fault there.

And so in updating, or in utilizing a reservoir model, and simulations to understand the resultant plume similar to the AGI #1 application efforts, and similar to what was presented in that associated hearing, we have utilized the Schlumberger PETREL platforms to construct the geologic simulation space.

Which effectively can be thought of as the digital container in which injection operations are simulated.

And then the associated Schlumberger ECLIPSE platform to conduct those simulations that include both the proposed operation of the AGI wells, as well as the operation of nearby SWD wells.

And so in this slide, the map shows the -- the -- it shows a map view of the geologic model that has been constructed.

In terms of its dimensions, it's -- it -- it remains the -- the same as the Independence AGI #1 well, in terms of its aerial expanse, covering about 20 square miles in southeast Lea County, New Mexico.

The boundaries of the simulation space were not increased for a couple of reasons. One being the number of wells that are included in the simulation did not warrant that those be expanded.

And then secondly, the expanding of the model in an area with limited well control, and outside of the -- the coverage area for our seismic, would lead to a lot of assumptions being made about the characteristics of the model in that space.

So for this period, and these investigations, it was not warranted to -- to increase that space without knowledge of how to characterize it.

While the model -- while the model dimensions have not been changed, the characteristics within the model, so porosity and permeability characteristics.

We have gained important data from drilling the AGI #1 and #2, that allow us to better represent the subsurface characteristics for our simulations.

And in this slide, we show just a -- a 3 dimensional render of the actual model that was produced.

While in the image, the color codes are generalized into eight discreet zones that are stacked vertically within the reservoir, the total simulation is -- is comprised of 292 simulation layers.

Which are then additionally subdivided into 500 by 500 feet grid cells leading to a rather large area, in which injection operations are simulated with the -- the model size reaching 920,000 grid cells.

And so in this slide, we provide kind of a summary table of how the eight identified zones are -- are -- the characteristics that -- that are ascribed to them.

And these zones are -- are -- were

generally delineated based on their -- their porosity and permeability characteristics.

And -- and so we see that, you know, upper zones appear, have varying average porosities than lower zones.

And -- and those are generally reflected in that -- or -- and this is the summary of how those are reflected in their average values in the modeling.

Taking a high level look at it, the average total porosity within the eight zones of the injection interval is 4.2 percent.

This is -- is based on our interpretation of well logs and the drilling of the Independence AGI #1. And then the permeability values that were utilized to inform the model again, were based on what drill stem test data are available.

Independence AGI 1 injection tests data as a separate injectivity test and a long-term falloff test was performed. And then further refined by the larger or significant studies on dolomite permeability.

And so moving to this slide, the panels that are shown in this slide are the -- are -- are -- we're -- we're showing how

porosity and permeability is actually distributed within the model.

As we discussed, we do have these porosity and permeability estimates are generated from what limited well control we do have.

And then further supplemented through analysis of the 3D seismic data and specifically mapping of impedance characteristics in the area.

So we see, taking a look at, and -- and you'll have to forgive me if -- if the scale is small. But the -- in the top left chart, we essentially have the distribution of porosity within the model.

And you can see that that general population ranges from about, you know, zero, or very near zero. Or maybe even more generally, 1 percent porosity, to about 6 percent porosity for most of the population.

And -- and that is essentially how that's distributed in each of those 920,000 grid cells. So that's the total population.

And then moving over to the panel to the right, we see how permeability -- for a brief second, we saw permeability was distributed in the model.

Yeah. So -- so seeing this

distribution in the bar chart with the -- with the blue colors, we see the permeability for most of the population ranges from around .1, .2 millidarcies to -- to about 30 millidarcies.

And you see the corresponding frequency of those values shown in the vertical axis of that bar chart.

With both permeability and porosity, based on our experience drilling AGI wells and completing AGI wells, testing the Siluro-Devonian reservoir via injectivity tests.

These -- these -- the way these characteristics are described in the model is -- is in accordance with -- with what we see -- with what we see in -- in actual wells drilled, completed, and operated.

Oh actually, Adam, if you can go back one more. And on the -- the -- sorry. I -- I failed to describe the bottom panel there.

And what is shown in the -- the bottom panel is just a cross-plot of the model permeability cross-plotted against the model porosity.

And it shows, essentially, you see looking at the data, you can probably pick out that there are eight unique trend lines where, you know,

those eight discreet vertical zones, each correspond to a colored trend line in that.

So obviously that we can see that there is -- in some zones, the model represents a stronger correlation between porosity and permeability than others.

So we can essentially expect that those zones with the stronger increase in permeability, with increases in porosity, will be larger receptors of acid gas.

And so in this slide, again, this is describe -- this -- this slide is intended to show you how characteristics are represented in the model.

And from those -- and essentially what is being shown here, is a -- a porosity map. So we're looking map view, top down again, at the -- at the simulation space.

And we have the porosity distribution within the model Zones 1, and 7, and 8, which based on the way porosity and permeability is distributed, are anticipated.

And -- and in fact, the results show that they are the two of -- two primary receptors of acid gas in our simulation. And also, that's in accordance with our experience with Siluro-Devonian

acid gas injection wells.

So moving on from how the characteristics of the model are setup, the -- with this geologic model constructed, we're able to simulate injection operations and start to get some insight into our initial question of -- of can this reservoir, as we understand it, sustain these operations that we're proposing.

And just to recap, the -- in -- well, in this slide, I'll recap the specific conditions of the injections simulations that were reported.

The AGI wells were simulated to inject a mixed acid gas stream, again, of 70/30 CO2 to H2S in accordance with -- with Pinon's current operations. And the simulation was conducted for a period of 30 years.

As the gas properties, the density and volume, based on temperature and pressure conditions, were determined utilizing the NIST REFPROP utilities.

Which is a comparable utility to Aqualibrium, which has been referenced in -- in many, many acid gas injection well applications. And essentially allows us to understand the acid gas characteristics for a given temperature and pressure.

For the injection wells included in the

simulation, but the AGIs and SWD were operated at their maximum anticipated injections rates.

Which correspond to the permitted injection rates for the entirety of the simulation in order to provide the most conservative results and assurance that the operations are reasonable.

The simulation assumes the reservoir is a brine-saturated reservoir in hydrostatic equilibrium. And the boundaries of the simulation, because of our understanding, are -- are kept closed.

And we assume that faults are -- are barriers to flow, are non-transmissive, which is a -- a common assumption, and is supported by what we know about a lot of these deeper Paleozoic faults.

Which have a long history of -- of trapping productive resources and demonstrating that they're not really transmissive of flow.

So in the work presented today, and in the -- the C-108 Application for the AGI #2 well, again, which was submitted at the end of last year, two simulations are presented here.

The first being injection via the AGI #1 and #2 well, at an injection rate of 10 million standard cubic feet per day for each well. Which is shown there, would equate to approximately 4100

barrels per day for each of those wells.

And this scenario was selected while we've explored several scenarios. This scenario was selected as the most reasonable because from an operational standpoint, it's -- it's kind of the ideal way to operate this well and to manage reservoir capacity.

It would be not very suitable to -- to plan to inject into one well for long as it -- it strains surface equipment more and ultimately has a greater and more rapid impact on local reservoir conditions.

So for what's presented today, that was deemed as the most suitable and most preferrable for long-term operation of the wells.

The second case being presented is similar in terms of the AGI will operate -- or the operation of the two AGI wells. But then it also considers operation of the nearby West Jal B Deep SWD at its maximum expected rate of 30,000 barrels per day.

So now, after a good deal of discussion about the foundation of the model, in the next kind of -- and -- and the simulation conditions, the next couple of slides, we'll be taking a look at the

results of that simulation.

And this and the next slide will follow the same format in that we see in panels A and B. The -- the maps that show one, the aerial extent of acid gas within two primary -- two zones that are the primary receptors of acid gas, that show the aerial extents as well as map the -- the gas saturation at the end of the 30 year injection simulation.

Panel C will show kind of a -- a resultant polygon that amalgamates the district -- the -- the lateral extent of all eight zones, to kind of show and illustrate, the maximum dispersion distance of acid gas at year 30 -- at the end of the injection simulation.

And panel D will show a cross-sectional view that illustrates both being a north/south cross-sectional view, that illustrates the distribution of acid gas vertically as a result of these injection operations that are being simulated.

So looking at these results, we see that at the 30 year mark, we see acid gas within Zone 1 reaching the farthest from the AGI well location at approximately 2.43 miles from the site.

Oh. I think you skipped that. We should be on Case 1. So -- so for Case 1, in which

operation is only at the AGI wells, had 10 million per day.

The maximum dispersion distance we see, is 2.3 miles and -- and certainly it's not a radial dispersion. But -- but towards the north, we see the greatest migration of that acid gas.

Generally, gas -- or acid gas saturation levels are highest near the wellbore, where we see reservoir concentrations within the grid cells ranging between about 30 to 50 percent.

And as we reach the margins of the plume, we start to see gas saturation values lower than 25 percent.

And in Case 2, again, following a similar pattern in terms of -- of the results being presented, we see -- and this case, just to -- to reiterate, this case would be the same 10 million standard cubic feet per day into each acid gas injection well.

But also with operation of the West Jal B Deep at a rate of 30,000 barrels per day.

And immediately, the -- one of the -- the first impacts we see, is we start to see a little bit more deflection of the acid gas plume away from the West Jal B Deep. So kind of inhibiting

migration to the northeast of the AGI well locations.

And we see that deflection resulting in a little bit farther reach from the AGI well bores, with the maximum extent reaching about 2.4 miles from the AGI sites.

Again, we kind of see a similar pattern in saturation with the nearest areas to the wells having saturation levels of 30 to 50 percent. And then being reduced towards the margin of each plume.

In both case simulations 1 and 2, we see, kind of in accordance with -- with our experience in the Siluro-Devonian, we Zones 1, 5, and then the lower most zones being the most productive receptors of acid gas.

And here we take another look at kind of at the results. And -- and what we have plotted here for Cases 1 on the top and Case 2 on the bottom.

And -- and you'll have to excuse me, but case 2 at the title of -- of that chart has a typographical error.

It says 15,000 barrels per day. But it is actually -- should read, 30,000 barrels per day and the -- this has been confirmed that the data represented on this slide are representative of that 30,000.

But in both of these charts, we're taking a look at the model's prediction for surface injection pressure required to inject at 20 million standard cubic feet per day, plotted against time.

And the two yellow trends, the solid yellow representing the Independence AGI #1, and the dashed yellow trend representing the #2 well.

Both show that for the complete 30 year simulation period, that injection can be maintained under the limitations of each respective maximum allowable surface injection pressure for the -- the complete 30 year period of operation.

And in this slide, again, this is kind of providing the -- the numerical equivalence of the results shown in the -- the prior cross-sectional view.

If you recall a couple of slides back, we looked at cross-sectional views of gas saturation and it was quite apparent that some zones were -- were being occupied by more acid gas than others.

This is the numerical breakdown for case simulation one on the left. And case simulation two on the right.

And we can see the model predicted volumes of acid gas at each of the eight general zones

will have received at the end of the injection -- the 30 year injection period.

So you see in column two, the cumulative injection reported in million standard cubic feet per day.

And in the following, the -- the column to the right of that, the cumulative injection in million barrels equivalent.

And then the fraction of the total acid gas injected, that each injection interval, or each reservoir zone has received in this simulation.

And lastly, the next couple of slides just show the initial and resultant pressure predictions for again, the two primary, or two of the major receivers of acid gas in -- in our simulations with that.

Essentially equating to the upper Devonian section, which is a very -- which is a -- a primary receiver in the existing AGI well.

And then the Fusselman interval, which is also a recipient of acid gas in -- in the current injection well.

And so here we see the same initial and end of simulation resultant pressure maps for Case Number 2, which should be immediately apparent, has

some -- some different results.

As that simulation considered also a significant volume being injected by the West Jal B Deep SWD well, at 30,000 barrels per day, for a period, day in and day out, of 30 years.

So just to summarize kind of the result of the -- this investigation, the -- based on our current understanding of the reservoir, and our conservative approach to simulating the -- the injection operations within this reservoir, the current model results, and our understanding, support the -- the ability, or confirm the feasibility of the reservoir in this area.

And the current injection operations that confirm the feasibility of Pinon operating the two wells at the combined rate of 20 million standard cubic feet per day.

And this is predicted to be feasible for the entire -- for a period of at least 30 years, and -- and can -- these operations can be maintained without any modification to the current maximum allowable surface injection pressures.

To reiterate, this -- in our simulations in our work was intentionally designed to be conservative just so that we can have as much

confidence as we can that the -- the work to actually operate these things, and attain approval, that we have as much confidence in -- in the reservoir's ability to receive these fluids as we can.

So as such, you know, injection simulations, all wells, were operated at their maximum anticipated or permitted rate such that -- that those conservative results can be arrived at.

In all case studies presented with and without the -- or without the contributions of the West Jal B Deep, all of those proposed operations, splitting 10 million between each well, can be maintained through the entire simulation.

When looking at the results -- no, you're fine. When looking at the results with and without the West Jal B Deep operating, we see a maximum dispersion distance between 2.3 and 2.43 miles from the AGI wellbore.

The results of the simulation are also in agreement with what we've seen in drilling and operating acid gas injection wells in the Siluro-Devonian Reservoir.

And then finally, and -- and quite importantly, is that with the simulation results that consider the increased volume, what we also see is

that the plume, while it is naturally larger due to a larger injection volume, we don't see it migrating or advancing into the path of any -- any other penetrations into the SWD well, or into the Siluro-Devonian Reservoir.

So we have confidence that -- that no additional pathways out of the reservoir, through a -- through an existing well that may or may not be plugged appropriately, are -- are going to present any issue to this application.

And so with an understanding, or confidence, that the injection reservoir can -- can receive the fluids being proposed at -- in a reasonable manner, that can be -- that can be completed within the bounds of the current maximum allowable injection pressures.

The next question becomes, does this increased injection volume present any elevated risk or any -- any significant change in the risk for induced seismic events. As there are faults in the area, which have been identified, and -- and need to be considered.

And so the second part of our reassessment completed for the C-108 Application for the AGI #2 and in preparation -- or in being presented

today, is a re-evaluation of that fault slip probability assessment that was completed both -- for both well applications.

Again, just to bring -- to -- to refresh everyone's memory about the local structure, in this map, we show again, the faults that have been identified in the area. Naturally, the area covers a pretty significant distance.

So the -- there -- there will naturally be faults that are a bit more relevant to the AGI locations than others.

And to -- to kind of reiterate again, these features were identified in review of 3D seismic survey data, which was also re-evaluated at the time of each application.

And so again, with modeling fault slip probability, or simulating injection operations to kind of assess fault slip probability, a series of -- of input parameters have to be identified, and -- and defined in the model and subsequent simulations.

These parameters, which are shown in the table here for the work completed for the Independence AGI #1 and #2, they essentially, are utilized by the model to describe local stress

conditions, the -- the orientations and the attitudes of subsurface features, which the model uses to essentially assign pressure values, or -- or conditions that are going to be necessary to induce slip along features in the area.

In the area of the Independence AGI #1 and #2 well, as we've seen in previous slides, most of the fault features are trending inline, or parallel to, the trend of the central basin platform, with a few minor fault features trending in -- in subparallel directions.

And while we have eight major fault features in the area that we've identified, in order to really accurately represent their kind of non-linear expressions in the fault simulation evaluation, those faults have been, as shown in this map, broken down into 29 fault segments.

So that those points along those features that may be more in alignment with regional stress directions, and therefore, more -- having a little bit higher potential for -- for slip, are adequately considered by the simulation.

So we'll see in this map, how each of those major fault features are broken down in their corresponding segment numbers that -- that we'll see

in the simulation results to come.

And one of the first things that the fault slip probability model, which I'm not sure if I referenced this, but the model being utilized is the Stanford Center for Induced Seismicity Fault Slip Potential Model.

Which is a pretty -- very quickly, become a widely used model for investigating the potential for slip and response to a variety of injection simulations.

And based on the structural data and the assumption -- the reservoir characteristics that are defined in the model, one of the first steps it takes is it tries to identify what the change in pressure for each of the fault segments being represented.

What the change in pressure is going to be that's going to be required to induce slip along that feature.

And so what we're showing here is for the 29 fault segments in which we've defined in the model. We're seeing the model's prediction of the pressure required to -- to induce slip along those features.

So immediately looking at the model's

predictions, we do see that the faults 1, 2, 5, and 6, as shown in -- in kind of the previous fault mapping, are the most -- are the features with the most likely -- are -- are the features with the most potential, or lowest pressure thresholds to induce slip.

With an -- with a prediction of, or an assessment of the geomechanics and -- and an understanding of the fault features in the area, we then inform the -- the fault slip potential model of the injection simulations that we'd like to simulate.

By -- so -- so that it can essentially complete a hydrologic simulation model. And start to make predictions about what the pressure impacts of each of those wells will be over the operation -- or over the periods for which they're being simulated.

So in our investigation of the area, where the Pinon Independence wells are located, we included seven additional SWD wells that are operating, or are planned to be operated in the area.

And what we'll quickly see is, you know, based on our understanding of the reservoir, some of these SWDs are located pretty far away on the eastern margin of -- of the -- of the study area. And really are anticipated to have some pretty minimal

impacts.

So similar to the reservoir modeling, we see, you know, West Jal B Deep, and -- and the AGI wells not being particularly affected by those wells much, much further out.

So actually, Adam, if you can go back one time.

So as we can see in the tabulated data for the seven injection wells that are included in the simulation, we see -- you can see that the injection volumes that we simulate, range from about 4200 barrels a day to 30,000 barrels per day.

As there are a couple of instances of SDW wells operating, or being at least approved for injection, up to those rates in the area.

There is one well at Jal North Ranch SWD that our review of records, it was -- it was not apparent what it's actual permitted injection value was.

So for our simulations, we assumed a value of 10,000 barrels per day.

As with the injection, the previous plume modeling simulations, all of the injection volumes, or all of the injection operations of these SWD and AGI wells, were -- were completed at their

maximum daily injection rate.

Again, to provide that conservative estimate of risk. And provide as much confidence that -- that the risk in fault slip in response to this proposed operation, is -- is not -- or -- or is -- is a manageable risk.

So in this slide, we see some of the results of the simulation, of the seven injection well simulation, which was operated for the AGI wells, or -- or for the period in which AGI wells were operated, was at least 30 years.

However, because some of these SWD wells have been in operation prior to the AGI wells, the total model -- or the total simulation duration was extended to account for those historic operations.

So with some wells, I believe beginning their operations circa 2010, we see the ultimate simulation period being in excess of 40 years.

And in the top panel, we see the FSP models predicted, or the results of the hydrologic model, where we see the pressure front generated from the operation of these seven wells.

And -- and noting immediately that -- that the resultant pressure conditions that the model predicts, falls pretty significantly short

of what the model also predicts, would be the pressure thresholds needed to induce slip along any of those features.

And we see each of those features, or the pressure conditions, along each fault -- each of the 29 fault segments being plotted in the chart to the bottom there.

In general, the results of pressure increase along these features, ranges from less than 1 percent to 20 -- 20 percent of what the model predicts is the pressure required to induce slip.

And in this slide, we also show some other demonstrations of the fault slip probability results with the top panel illustrating the fault slip potential predicted by the FSP model, through time, with each of those fault trends being plotted in the black trend line.

So we immediately see that -- that along all 29 features simulated, there's not really any elevated risk of slip probability for any of these features based on this particular injection scenario.

For most of the 29 fault segments, the model predicts a probability of 0.00 probability of slip.

However, there are five, or I'm sorry,

four segments for which the model does predict non-zero probabilities.

And these are shown in the map, the lower map, on this slide. We see segments 4, 5, oh. I'm sorry.

It is five segments, 4, 5, 16, 17, and 18, having probabilities ranging from .01 to .05, based on, or in response to the seven injection well scenario.

So in this slide, we also show again, the same plot of fault -- model predicted fault slip probability plotted against time in the upper panel there.

And then the specific model predicted results, or the specific model predicted change in pressure required to induce slip.

The model predicted pressure change for the seven well scenario. The associated probability that those conditions will be reached and induce slip.

And then the final column representing the probability of slip for those five features for a subsequent simulation in which the AGI wells are not included.

So immediately in that comparison, we see that the volume, the approximate 4,000 barrels per

day equivalent, that the two AGI wells are contributing, are not producing, well, in this iteration, any noticeable change to the probability of slip.

Which would -- which would suggest that any observable risk of slip, is kind of being driven by adjacent SWDs or the higher volume injectors in the area.

With that -- even considering that, we observed that generally these features, these fault features, these eight fault features, are generally not predicted to be of significant risk of injection induced slip for this seven well scenario.

Again, subsequent simulations that remove the AGI injection contributions, really produce no noticeable result, or no noticeable change in the probability of slip.

And ultimately, as proposed, the AGI wells at 20 million standard cubic feet shared between the two wells, can be completed.

And those wells can be operated without significantly increasing the risk of injection induced slip in the area.

So to just kind of summarize the -- the materials presented, including the background

materials, and the request of Pinon.

Again, Pinon is requesting approval or amendment, of the existing Commission Order to allow for a combined, or shared, daily injection volume limitation of 20 million standard cubic feet for the AGI wells 1 and 2.

These wells, both well #1 and well #2, have been authorized for injection into the Siluro-Devonian interval.

One, via the Commission -- or via the hearing process before the Commission. And one, via the administrative route.

Independence AGI #2 was authorized earlier this year, in March of 2020 [sic] however, as we discussed before, the -- the request to increase the total volume limitations was not able to be considered through the administrative process.

In our additional work to evaluate the reasonableness and the feasibility of maintaining these injection operations, our revised modeling, which is better informed through drilling and completion of the AGI #1 well, and -- and further refined through detailed analysis of 3D seismic data, confirms that -- that this is a reasonable request of volume for this area, and -- and the reservoir.

Both log data and well test data support its ability to -- to receive these fluids in a safe manner.

Summarizing the -- the conditions of the -- of the modeling and simulation again, to reiterate PETREL, or Schlumberger PETREL and ECLIPSE software platforms were utilized in our investigation.

And the results of that indicate that based on the two case studies it simulated, the resultant acid gas injection plume would extend from the AGI wells between 2.3 to 2.4 miles from the current wellbores.

Being controlled and deflect -- or being controlled, or with the main difference between those two case studies, being the operation of -- of the West Jal B Deep.

The simulation results also confirm that the operation at this rate can be maintained throughout the entire period for which Pinon is -- is requesting.

With the results showing that surface injection pressures can be -- can remain under the maximum allowable pressures for the entire period.

Additionally, revisiting our assessment of fault slip probability, or fault slip potential,

those results as well, confirm that based on our understanding, these -- these wells can be operated as such without any significant risk of -- of producing induced seismic events.

So the -- moving back to the ultimate request of Pinon. Pinon would request approval to operate the Independence AGI #1 and #2 at a combined daily injection rate of 20 million standard cubic feet per day.

The AGI #2 well is currently being drilled and is currently on target to meet all of the condition of the Commission's requirements with respect to the redundant AGI well.

The -- the -- again, to reiterate the ask of 20 million standard cubic feet per day is -- is a reasonable request and -- and really only a moderate increase as under reservoir conditions.

Again, the -- the acid gas would equate to approximately 8200 barrels per day within the reservoir. Again, significantly less than many SWD wells operating in the basin.

The operation proposed can be maintained without any increase to the maximum -- maximum allowable surface injection pressures. And as such, we're not requesting any

modification to those conditions.

And ultimately, as proposed, based on our investigation, the operation at this rate, can be done safely. And -- and it will allow Pinon to meet the local needs for -- for acid gas disposal in the region.

BY MR. RANKIN:

Q Mr. White, in summary then, it's your opinion that the granting of Pinon's Application will protect human health and the environment in this case?

A It is.

Q And in your opinion, will operation of the two AGIs at the proposed injection rates result in waste or impair any correlative right?

A No.

Q And in your review and analysis, it's your opinion that the target interval here will have, and does have, the capacity to accept the volumes of the treated acid gas at the rates that are being proposed for the life of the wells?

A Yes. I do.

MR. RANKIN: Madam Chair, at this time, I would move the admission of Pinon Exhibits A through E.

And the last bit of our presentation is

to touch on and review the Notice.

But I know -- I realize that we have proceeded through a lot of material and the Commission may wish to ask questions now, or the Division may wish to ask questions now, or we can finish up by just reviewing the Notice.

CHAIR SANDOVAL: Go ahead and finish up, and then we can enter exhibits, and then proceed with questions.

MR. RANKIN: Thank you, Madam Chair.

BY MR. RANKIN:

Q Mr. White, did Geolex prepare, and issue notice of today's -- this Application? Today's hearing?

A Yes. We did.

Q And is that Notice reflected in Exhibit F of your exhibit packet?

(Exhibit F was marked for identification.)

A Yes. It is.

Q And does that exhibit packet include a sample notice letter that was sent to each of the parties?

A Yes. It does.

Q Does it also include all the green card

receipts reflecting the status of delivery of each of those notice letters that went out?

A For -- yes. For the 14 of the notices sent out, we did receive green cards, return receipts, confirming receipt of those materials.

For one certified mailing that was sent, the -- the address was found to be vacant. And we followed-up with a Federal Express overnight shipment to a corrected address for one interested party.

And then for two additional certified mailings that went out, those -- those mailings are still in transit according to the USPS tracking system.

When that "In transit" status was identified, we reached out via electronic mail, to contacts at those two entities, to provide them immediate electronic versions of all of the materials that were sent in the original certified mailing notice.

And -- and those correspondence, via electronic mail, and the subsequent overnight FedEx shipment details, are included in this exhibit as well.

Q And the one party that you received notification that the location was vacant, that was

for NGL Energy Partners.

And that address was the address provided on their corporate website. And it still is provided on their corporate website. Is that right?

A At the time. I don't know if it's current. How -- how it -- what -- what it's currently. But at the time, yes.

Q And that subsequent attempt to deliver by overnight mail was successful?

A Yes. It was.

Q And in addition, Mr. White, did we also prepare a Notice of Publication in the newspaper of general circulation in the location where the well is located?

A Yes. We did.

Q And has that been marked as Exhibit G?

(Exhibit G was marked for identification.)

Let me get to it. See if I can get to it.

Is this a copy of the Affidavit of Publication reflecting that Notice of this Application Hearing was provided in a newspaper of general circulation in the county where the wells are located?

A Yes. It is.

Q And you identify each of the parties,

affected parties required to be noticed by name in this publication?

A Yes.

Q And these same parties were noticed as well for the C-1 -- Administrative C-108 Application that was approved by the Division. Correct?

A Yes.

Q And none of those parties --

A As well as additional parties that are now of interest at the time of the hearing.

Q And included in that list was the State Land Office and the BLM. Correct?

A Yes.

MR. RANKIN: Thank you, Mr. White. At this time, Madam Chair, I would move the admission of Exhibit A through G into the record if there are no objections.

CHAIR SANDOVAL: Mr. Tremaine, any objections?

MR. TREMAINE: No objections.

CHAIR SANDOVAL: Any objections from any other Commissioners?

COMMISSIONER BLOOM: No, Madam Chair.

DR. AMPOMAH: No, Madam Chair.

CHAIR SANDOVAL: All right. Exhibits A

through G are entered into the record.

(Exhibit A, Exhibit B, and Exhibit D through Exhibit G, were received into evidence.)

MR. RANKIN: Madam Chair, at this time, I have no further questions of Mr. White.

And will pass Mr. White for questions by the Division and the Commission. Thank you.

CHAIR SANDOVAL: Thank you.

Mr. Tremaine, do you have any questions for the witness?

MR. TREMAINE: Very briefly. I think I have one question, Madam Chair.

CHAIR SANDOVAL: Okay. Go Ahead.

CROSS-EXAMINATION

BY MR. TREMAINE:

Q Mr. White, I think we've heard today, that as Pinon has kind of developed its business, that the need for maximum injection rate has changed from what Ameredev originally -- or projected to be 12, now it's at 20.

My question for you is, is there any reason to believe that as Pinon continues to develop this facility, and develop its business, that you would expect any further increase in injection down the

road?

A So -- so I don't -- I don't know if I would have the -- the, I guess the -- the forecast data, or -- or the demand data that Mr. Green may have, that kind of would be at -- be -- allow me to better -- be better informed in answering that question.

What I would suspect is, or -- or what I would say is if that was pursued in the future, then it would be, you know, reasonable.

And -- and similar investigations as -- as to the ability of the reservoir to continually either maintain, or -- or to receive those fluids without detrimental effects, would need to be done as well.

But whether or not it's forecasted and -- and likely to be requested, I don't think I have -- I -- I don't know if I could speak to that.

Q I understand. Thank you. That may have been a better question for the other witness.

In terms of that process, if Pinon determines in a year or two that it -- there's 25 MMSCF of injection, or 30, would Pinon undergo a similar process of updating the modeling and running these projections?

A I would assume so. And -- and I don't -- I don't think it's been discussed.

But part of the requirements of the original Order, required a -- a periodic and continual update of that geologic model.

Which, to be frank, is -- is going to -- you know, our understanding is going to improve with every iteration of that.

Because we can start to see how our model predictions line up with what we're actually experiencing in terms of operating pressures.

And essentially take each of those to kind of history match and -- and kind of true up our model and our understanding.

So I would assume -- based on my experience with Pinon, pursuing any approval for any additional increase, would -- would be accompanied by a -- a significant investigation into the feasibility.

And -- and as well, the -- the ongoing requirements of the Order will help to kind of keep our understanding of -- of the feasibility in check, I think.

Q Okay. Thank you.

MR. TREMAINE: No further questions.

CHAIR SANDOVAL: Thank you. Commissioners, do you have any questions for witness?

COMMISSIONER BLOOM: No, Madam Chair.

DR. AMPOMAH: Yeah. Madam Chair, I do have questions for the witness.

CHAIR SANDOVAL: Okay.

DR. AMPOMAH: Okay. Yeah. So Mr. White, so we do have the Woodford Shale being the cap rock for the Devonian that we are -- that Pinon is targeting.

So but there has also been a lot of production and more like horizontal wells through the Woodford Shale.

So my first question is in the location that Pinon is looking at, are there any activities going on in the Woodford, which can more or less compromise the integrity of the ceiling?

THE WITNESS: No. At this time, I am not aware of any Woodford Shale development that would be occurring in the area of the Pinon wells.

Overlying production is primarily dominated by Bone Springs and Wolfcamp, which is separated by thousands of feet of strata.

DR. AMPOMAH: Yeah. So you talked about how you've used information from the AGI #1 well to update the model that you presented to us today.

And also, even now, you have the AGI #2 still drilled -- being drilled at this point.

Let me ask. Did Pinon take any core from the AGI #1 well?

THE WITNESS: Yes. They took sidewall cores.

DR. AMPOMAH: So did they measure permeability from this core?

THE WITNESS: Yes.

DR. AMPOMAH: I didn't see, in the modeling, where you included that kind of probability in your modeling.

Aside, you talked about -- and even I didn't see the core measurements being made mention of. You talked about using the DST to calculate, or to, more or less, get the permeability.

So would you confirm to the Commission whether you incorporated the core measurements, probability measurements, into the modeling efforts?

THE WITNESS: So the core measurements were utilized to inform our revisions to the model. But ultimately, in -- in some of the more productive intervals, where injection or are separate injectivity tests, and falloff tests.

Where those -- those test indicated the most volume of fluid was going, such as the upper Devonian and Fusselman intervals.

You know those -- those intervals are usually productive because there hasn't been a fractured solution enhanced porosity, or a solution enhanced rock there.

And so naturally, for recoveries along those most productive intervals, was not very good. Most of the core recovery that was successful was in the overlying Mississippian section, the Woodford Shale Section.

And then some more of the tighter intervals of the Siluro-Devonian kind of in between the Fusselman porosity and the upper Devonian porosity.

DR. AMPOMAH: So when you say that probably if Pinon could have recovered a conventional core compared to a sidewall core, probably the recovery rate could have been improved.

THE WITNESS: Potentially.

DR. AMPOMAH: So in the DST measurement, you also measured reservoir pressure. Right. So I wanted to know if you went back to look at a 4.3 -- 0.43 psi per foot, initial reservoir pressure that you used in the model -- to initialize the model, did you go back to check for consistency?

THE WITNESS: Yes. Yes. The

geomodelling team would -- would have done that.

DR. AMPOMAH: Would have, or probably they did, or you're not sure?

THE WITNESS: At this time, I would need to confirm that.

DR. AMPOMAH: Okay. Yeah. Because that is very necessary, as you know.

THE WITNESS: Yes.

DR. AMPOMAH: You know, because we are using .43 psi per foot, which is a good assumption, but you have the opportunity to do deep DSTs, so definitely you measure the reservoir pressure at that point.

So you want to make sure that you check the consistency in there. And if not, probably in -- reaching of the models, you probably have to check into that.

THE WITNESS: Yeah.

DR. AMPOMAH: So you talked about the porosity probability of relationships, and you made mention of the Winland R35 that you used, so I want you to be clear to the Commission, how the permeabilities were modeled.

Is it based on just statistics or based on the Winland R35 equations?

THE WITNESS: So the -- the way, from my understanding, that the -- the way permeability is populated in the model, was using the Winland R35 method.

And that was done for the purpose -- or -- or the purpose in utilizing that method was because, I guess, more standard distribution methods really didn't produce any simulation cells that were lower than .1 permeability, so -- or -- or .1 millidarcies permeability.

So we didn't find that to be reasonable with respect to how these wells behave. And so it -- the -- it -- it was recommended that those -- that that method be taken to -- to ascribe permeability characteristics within the simulation space.

DR. AMPOMAH: That was great. So you talked about how you used a caustic containers inversion for the porosity. Yeah. So you have a big seismic, so at least you're able to -- porosity from the seismic.

I didn't see a lot of information on that, so can you clarify that you were able to do inversion on the seismic to get the porosity to help improve the model?

THE WITNESS: So impedance data were available to us for review. The -- the inversion was not completed by Geolex.

And ultimately, the way that that was incorporated into the model, was such that -- that, you know, we don't -- they all -- the licensing terms of those data are not breached.

So while the model was not constructed to -- to directly represent any of that, it was utilized to kind of better inform and make more realistic, those results.

DR. AMPOMAH: Thank you. So let's get to the model impact.

So you have one saltwater disposal well. And then also the AGI #1 well. So first of all, are they all active, injected now?

THE WITNESS: I'm sorry. Can you say that again?

DR. AMPOMAH: So the saltwater disposal well and the AGI #1 well, are they all active now?

THE WITNESS: Yes.

DR. AMPOMAH: So then in your plots, profiles that you show, I didn't see any history match in work done before the forecast.

THE WITNESS: Yeah. And -- and

ultimately, that's going to be as more AGI #1 and #2 well data are -- are yielded from their operation.

With the Commission's schedule to revisit this model, those will be the long-term goals of this evaluation.

But ultimately, on the initial investigation, it was not part of the scope to -- to include all of those.

And but rather to take a conservative approach for operating volume to assure that our confidence in -- in the reservoir's ability to maintain that is in place.

DR. AMPOMAH: So what is the distance between AGI #1 and AGI #2?

THE WITNESS: Bottom holes are separated by a little over 3,000 feet.

DR. AMPOMAH: 3,000 feet. So are they not close enough? Or is it okay?

Because I'm thinking about, did you guys do any interference test to make sure that you are maximizing the -- space, you know, to be able to co-inject both wells without any pressure issues?

THE WITNESS: Though the -- the main motivation between separating the wellbores was ultimately to take what information we received from

drilling the AGI #1 well, and identify what appeared in the seismic data, to be an even better potential location in terms or reservoir characteristics.

So that location was cited based on, you know, a better understanding of what the data and the seismic survey really mean.

So that was the primary motivation for selecting that location.

DR. AMPOMAH: Mr. White, in the fault modeling, so you showed two faults that were incorporated in the model.

Now, I saw that these are non-transmissive faults. Or so it means that it has transmissibility zero. There's no fault across.

Now, if you look at -- so if you look a slide number, probably 28. So why did you not run another scenario where these faults were okay?

Or let me ask it this way. How was the transmissibility calculated for this particular faults?

THE WITNESS: So -- so based on our -- the reason it was not explored for this simulation, is that we -- we made the -- or in our experience, these faults that are generally confined to the lower Paleozoic section, don't have a lot of

extension vertically, up into other producing zones.

You know, most of the population of these faults, have behaved and -- and are demonstrated as -- as competent traps.

And -- and so we felt that that was the most reasonable assumption for this area.

DR. AMPOMAH: So in that case, you don't believe that there's any chance for the faults to be okay?

THE WITNESS: I'm sorry. I -- I believe that either mine or -- or your connection broke up. Could you repeat that?

DR. AMPOMAH: So I'm saying that so are you confident, you know, saying to the Commission, that these faults are strictly closed and cannot be opened?

THE WITNESS: I'd say that is the most likely scenario. And provides the most conservative estimate of the plume migration in that assuming these faults to be closed, significantly reduces the -- the available reservoir in which acid gas can occupy.

And -- and should the -- the open fault simulation be considered, it's likely, based on -- on the well data, or the existing wells, it's not likely to come into contact with any other Devonian

penetrations.

So having an understanding of the maximum extent that the plume may reach, may be a more, at this time, a more useful investigation for us to assure that -- that we don't reach any penetrations that could be conduits out of the reservoir.

DR. AMPOMAH: Mr. White, so let me go back to what I asked about the core measurements.

So I presume, based on your testimony, Pinon did routine core analysis on the core -- on the -- let's say the sidewall core that it took.

What about special core analysis for relative -- and capillary pressure measurements?

THE WITNESS: So I don't have those data, or not familiar with the specifics. But I don't believe that those were -- were completed.

DR. AMPOMAH: Yeah. So that is -- if you can bring up the slide number 28. Yeah. One of the plumes that is showed.

So my main concern is how did Pinon calculate the irreducible water saturation? You know, so what was the source of the original perm curve that you use in the modeling?

THE WITNESS: So the source was -- the source -- well, there were multiple relative perm

curves utilized in the models to -- to characterize the behavior within each zone.

And those were -- were determined from a collaborative effort of -- of evaluating the well data collected, and reasonable assumptions for our understanding of the reservoir in this area.

DR. AMPOMAH: Yeah. But don't you believe that if you want to get the actual data, then get in the core, and then doing the flow to experiment on the core.

Like a special core analysis give you. They have data for you to be able to get the test.

Because if you look at the plume that you are showing, I want to see, in terms of the what is the maximum saturation of the water that cannot be displaced by the injection that you are putting into the well.

And if you do not do the -- planned experiment, how do you account for that irreducible water saturation?

THE WITNESS: Well, I certainly do believe that that may be the most suitable approach. But I don't know if -- if the actual core recoveries would've been truly reflective of that.

And -- and when you have the -- the

disparity, and where injection fluids are going, versus where your core recovery occurs.

DR. AMPOMAH: So let me try to wrap it up quickly. And I'm sick today, so it probably is good for you.

But let me ask. What was the minimum horizontal stress that you used in calculating the maximum fracture pressure?

THE WITNESS: You're referring to the later portion of the -- the presentation where fault slip probability?

DR. AMPOMAH: Yeah. But even within the modeling. So let's say you use the minimum horizonal stress to, more or less, know the maximum -- pressure that you can go. Right.

So in the current modeling, what was the minimum horizontal stress that you utilized?

And I'm sure you used that in the fault slip analysis as well.

THE WITNESS: Yes. And -- and that particular variable, or value, is not shown in this. However, you know, it is engrained in the simulation.

And we can, if over a break, we can probably grab that number, and let you know what it is. What the model assumption for that is.

DR. AMPOMAH: Okay. So it to be good that you include that in the final admission -- that -- the final documentation. And I presume it is a normal -- routine. Right?

THE WITNESS: Yes.

DR. AMPOMAH: Okay.

CHAIR SANDOVAL: I just want to jump in real quick.

I think if, Dr. Ampomah, if they haven't provided us with the information previously, they have submitted their prehearing statements, they submitted their exhibits.

They can't really provide us with more information if they didn't think to include that in the beginning.

THE WITNESS: Okay. And I can provide a little bit of -- more information on that.

So the way the Stanford model is constructed, that -- those values that Mr. -- or Commissioner Ampomah is requesting, is represented and defined in that particular model by the eight feet parameter.

So what I can do, maybe we can -- I mean, obviously that eight feet parameter can be utilized to see what those -- those stress conditions

are if we -- if we cannot provide that.

DR. AMPOMAH: Yeah. And, Mr. White, you know, let me be clear that the questions that I'm asking is probably mostly for the regulator to see how they review the models that are presented, you know, to the Commission.

So the last one, you use ECLIPSE for the modeling.

Did you look at the reaction between the injected fluid, that is the H2S and the CO2 with the -- fluid and also the metrics to see how the injection that you are doing, how the fluid is stored?

THE WITNESS: You mean in the simulation itself? Does it consider those other sinks? No. It does not.

DR. AMPOMAH: Why?

THE WITNESS: At this point, I just don't think enough information has been explored to -- in order to pursue that type of investigation.

You know, the modeling, we could also, and maybe a longer term goal for this as the model is revisited, is even to produce a dual-porosity model where we start to consider the role of fractures versus matric porosity.

So I think at the point where it

becomes, or the data available to us become the operating data to where we can start to further refine that.

Some of those things kind of be -- be brought into scope with that.

DR. AMPOMAH: Thank you, Mr. White. Madam Chair, I'm going to end here. Thanks so much.

CHAIR SANDOVAL: Thank you. I think you very eloquently asked the majority of my questions. So I do not have anything -- actually, I have one question.

The only question I have is, I just want to make sure I understand what -- what you guys think is going to be the injection pattern.

Like, how are you planning to use the wells? Are you planning to inject in one at a time?

Are you planning to inject equally in both? With a total capacity of 20. What is kind of the injection plan?

THE WITNESS: So -- yeah. So -- so as we simulated in -- in the plume modeling investigations, we think the long-term average for this is going to 10 and 10 into each.

Which represents, you know, with bottom hole locations separated by some distance, it is -- we

feel that's the best management of our impact to the reservoir. So long-term, we feel that it's going to average like that.

Pinon's intent, if I understand correctly, is that this -- these wells will be operated simultaneously. Maybe with some small fraction going to one well and the majority going to the other well.

So maybe -- so maybe 5 and 15 for a period. Or 6 and 14 for a period. And then alternating the -- those conditions between the two wells, such that operational readiness of both systems is maintained at any point.

And we don't deal with any scaling, or -- or issues that may result from downtime of the one well completely.

But I think over the long haul, the 10 and 10 is -- is how it will likely average out.

CHAIR SANDOVAL: Okay. And then if for some reason, both wells were to go down, so the point of the redundant wells, if one well goes down, you can shift injection to that one -- or to the other one.

If both wells were to go down, what is the operational plan?

THE WITNESS: So I think in terms of

how that is planned out, may be a question more suited for Pinon.

In -- in considering the downtime of one well, the -- they separate injection tests that we've completed on the Independence AGI #1, are currently supported that if, for a period of time, one well had to take all of the flow, then that would be a reasonable operating parameter, for at least a short period.

With the -- in the event that both wells go down, I know Pinon does have a -- or the operators that Pinon service, many of those operators have the ability to immediately and remotely shut in a lot of the -- the wells that are contributing to that gathering system.

So there -- there is some volume that can be immediately shut in without going to flare.

And I think, again from my experience, I think this can be done in a matter of minutes for a lot of their infrastructure.

So I think there -- there -- I think, in the event that -- that both wells go down, there -- there's certainly some options for Pinon.

CHAIR SANDOVAL: Okay. That's all of the questions that I have. Mr. Rankin, do you have

any follow-up?

MR. RANKIN: Madam Chair, I do not. I appreciate the Commission's questions.

And at this time, we have no further questions or information to present. So we rest our case.

And I guess, now being noon, unless you want to proceed with the Division's case, you know, we can proceed as the Commission desires.

CHAIR SANDOVAL: Okay. Mr. Tremaine, how long do you expect your presentation to go?

I think we're going to take a break, but just for planning afterwards?

MR. TREMAINE: Well, I think that ours will be fairly quick. I will say less than half an hour.

CHAIR SANDOVAL: Okay.

MR. TREMAINE: We were not planning to get into kind of extensive details but are available for additional questions.

And I do expect Commission questions. So I'm not sure how long that will go.

CHAIR SANDOVAL: Okay. All right. It's 12:05 basically. Let's come back at 1, and we will pick up with the Division.

I will leave this going, so you're welcome to either stay on, just turn off your video and mute, or you can drop off and then come back on. Thanks.

THE REPORTER: Okay. Going off the record at 12:04.

(Off the record.)

CHAIR SANDOVAL: It's one o'clock. And we will pick up where we left off, which was I think starting with the Division.

But I think we have one maybe a piece of announcement prior to that.

MR. MOANDER: That's your cue, Dr. Ampomah.

DR. AMPOMAH: Yeah. Thank you, Madam Chair.

You know, in the interest of justice, I will ask to recuse myself for the remainder of the proceedings. Thank you.

MR. MOANDER: Thank you, Dr. Ampomah. And I think -- well, with that, are any of you -- yeah. Thank you.

CHAIR SANDOVAL: Okay. All right. So we will proceed I guess, with just Commissioner Bloom and I. But it is still a quorum. And so we are able

to proceed. All right. Mr. Tremaine.

MR. TREMAINE: Madam Chair, the Division has one witness, Mr. Dylan Rose-Coss. Call him at this time.

CHAIR SANDOVAL: Okay. Mr. Rose-Coss, can we hear you?

MR. ROSE-COSS: Can you hear me?

CHAIR SANDOVAL: Yes. All right. Will the court reporter please swear in the witness?

THE REPORTER: Okay. Can you please state your full name for the record?

MR. ROSE-COSS: My full name is Dylan Henry Rose-Coss.

THE REPORTER: Thank you very much. Can you please raise your right hand?

WHEREUPON,

DYLAN ROSE-COSS,

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:

THE REPORTER: Thank you very much.

THE WITNESS: Thank you.

CHAIR SANDOVAL: All right. Go ahead, Mr. Tremaine.

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DIRECT EXAMINATION

BY MR. TREMAINE:

Q Mr. Rose-Coss, where do you work?

A You know, I -- I work for the State of New Mexico within the Energy, Minerals, and Natural Resource Department.

Specifically, within the Oil Conservation Division, UIC Team.

Q And what is your specific position within the Division?

A I'm specifically classified as a petroleum specialist advanced.

Q And could you please summarize your responsibilities as a petroleum specialist advanced for the Commissioners?

A You know, by and large, at the generality of what you would say I do, is review applications for compliance, impose these rules.

By regarding the prevention of waste, and the protection of correlative rights, public health in the environment. I also serve as a technical examiner for these hearings at OCD, that level hearings.

Specifically as a member of the UIC team, what you would say I do is applications and compliance for Class II disposal wells within the state. UIC

Class II disposal wells.

Q Thank you. Mr. Rose-Coss, have you prepared a CV for this hearing?

A Yes. I have.

Q And is that marked as proposed OCD Exhibit Number 1?

(OCD Exhibit 1 was marked for identification.)

A It is.

Q And is that a true and accurate description of your relevant education and experience?

A It is.

Q And now, would you please summarize for the Commissioners, your education and experience?

A Sure. Well, as you can see on the CV, I have over eight years of experience in, kind of public, or resource management.

You know, prior to that, or the way I got into the field, again at UNM many moons ago, where I received a bachelor's in science and a distributed science minor in Environmental Science.

Which I follow-up with at again, at UN -- University of New Mexico with an Earth and Planetary Science Degree, which is their -- UNM's form of a geology undergraduate.

Which I then proceeded to follow-up with at the University of New Mexico Tech, where I received a master's degree in -- in geology.

And during that time, you can also see from my CV, that I have three peer review publications and five conference level papers regarding the underground, kind of -- reservoir characterization and underground sequestration of carbon dioxide.

So my -- my job was to follow -- master's degree and kind of, New Mexico Tech was with a resource consulting firm, water rights consulting firm in Santa Fe called Glorietta GeoScience.

That let me -- that -- which I followed up with by taking position with the Oil Conservation Division as an environmental specialist. Mostly reviewing spills and releases from the oil field.

And then I moved into, and I've held the position for three years now, as petroleum specialist advanced with the UIC Team.

Q Okay. When you were getting your master's at New Mexico Tech, did you specialize in any particular areas?

A Yes. You know, I -- I did specialize with -- at New Mexico Tech, in petroleum geology, and reservoir characterization, and actually earned a lot

of experience at my time there in oil reservoir modeling and simulations.

Specifically, kind of relating core measurements to reservoir modeling.

Q And for what types of cases do you typically or normally appear as a technical examiner for the Oil Conservation Division?

A Sure. Yes. You know, so -- so by and large, the cases that I hear as a technical examiner, are for compulsory pulling.

But when I'm -- with my specialties -- specialty is called on the most, is during hearings regarding saltwater -- contested saltwater disposal wells.

Q Okay. Thank you. Have you ever testified before the Commission before?

A I have not.

Q All right.

MR. TREMAINE: Madam Chair, at this time, I would move admission of OCD Exhibit 1, Mr. Dylan Rose-Coss' CV.

And also ask that the Commission qualify Mr. Rose-Coss as an expert in the areas of petroleum geology, petroleum engineering, and underground injection.

CHAIR SANDOVAL: Mr. Rankin, any objections?

MR. RANKIN: No objection.

CHAIR SANDOVAL: Okay. Commissioner Bloom, any objections?

COMMISSIONER BLOOM: No, Madam Chair.

CHAIR SANDOVAL: Okay. OCD Exhibit 1 is entered into the record.

(OCD Exhibit 1 was received into evidence.)

And Mr. Rose-Coss is certified as an expert.

MR. TREMAINE: Thank you, Madam Chair.

BY MR. TREMAINE:.

Q Mr. Rose-Coss, have you -- I want to refer you to the particular matter at hand.

Have you had an opportunity to review Pinon's Application on behalf of the Oil Conservation Division?

A I have.

Q And when you review an application, such as the one submitted by Pinon in this case, what types of things are you looking for?

A You know typically, when an application for injection comes before the Division, we first review

it for simple administrative completeness.

And the administrative completeness review involves checking notice to affected parties and -- and verifying that all affected parties were noticed.

And should the application be clear of any issues of, in terms of general completeness, it moves onto a technical review, where the kind of aspects of geology and engineering related, you know, to correlative rights, and protection of the health in the environment, are evaluated.

So mainly, what wellbore design depicts the formation tops such as that and ensuring that the well is going to be constructed in a manner to protect the, really the water rights and correlative rights.

And you know, should a application from there, have any issues or be protested, is when it's elevated to a OCD hearing level, which have a more thorough review, is undertaken of the technical aspects of the -- of the application.

But mainly, in -- in those instances, by and large, for correlative rights issues, a hearing of affected parties.

And in this case at -- for TAG or acid gas injection wells that come before the Commission, you

know, if further analysis of the technical, kind of specifics, of -- in terms of the computer simulated modeling, are reviewed, and evaluated for efficacy, and validity.

Q Pardon. I muted myself there.

And, Mr. Rose-Coss, did you conduct the review that you described of Pinon's Application for this case?

A You know, yes. We did. I, and the other members of the UIC technical team, did carry out a thorough review of this application.

And since the filing of the prehearing statements, have -- have indeed, reviewed all of the material submitted. And as it stands, do not disagree with the modeling or oppose the Application.

However, you know, the Division would like to take the opportunity to reiterate its stance that, you know, it agrees that, AGI wells present a unique oil field opportunity.

But they also represent a unique oil field risk. And therefore, we maintain that they be regulated consistent with these elevated concerns, for correlative rights, waste, and public health, in the environment.

And believe the future major mods should

return to the Commission. And their -- and that their redundant well is still necessary, and that all of the conditions set forth in the existing Order need to be adhered to.

Q So, Mr. Rose-Coss, am I understanding correctly that consisting with what you just outlined, and the previous conditions set forth in the Order, that the Division is not recommending any additional, or new conditions of approval for this Application?

A No. No. We're not recommending any additional conditions at -- at this time.

Q Just a moment ago, you referenced, kind of unique risks associated with acid gas injection wells and the types of things that you, as a technical reviewer, looked at the Application -- reviewed the Application for.

Has OCD discussed these general concerns with Pinon directly?

A Yes. We have. The OCD, at the Division level, is -- did have a meeting with Pinon Midstream preceding this case, in which these concerns were elaborated on, and basically, Pinon explained how their -- model was generated.

And updated with the latest information that was made available to them through the drilling of the

Independence AGI #1.

And that proof, that presentation, was consistent with the material presented today here.

Q Okay. And now we'd like to draw your attention to what's marked as OCD Exhibit 2.

(OCD Exhibit 2 was marked for identification.)

Mr. Rose-Coss, what is Exhibit 2?

A You know, Exhibit 2 is a list of the current AGI wells that are tracked and monitored for the State of New Mexico by the UIC Team.

And -- and the list is really just presented to illustrate the current state of AGI wells in the state. And highlight the elevated regulatory lens used to monitor these wells.

And we'd also just like to say that we're ready for -- to answer questions that the Commission might have regarding the state of the State's AGI Well Program.

Q Okay.

MR. TREMAINE: Thank you. Madam Chair, I would move to admit OCD Exhibit 2.

CHAIR SANDOVAL: Any objections, Mr. Rankin?

MR. RANKIN: None.

CHAIR SANDOVAL: And Commissioner Bloom?

COMMISSIONER BLOOM: No, Madam Chair.

CHAIR SANDOVAL: Okay. OCD Exhibit 2 is entered into the record.

(OCD Exhibit 2 was received into evidence.)

BY MR. TREMAINE:

Q Okay. So, Mr. Rose-Coss, I'd just like to ask you directly, at a general level, what are the unique risks that OCD associates with AGI wells?

A Well, you know, first and foremost, the -- the general risk of a -- of it being kind of a potentially dangerous gas that's going to be transported, and high-pressures, and concentrated.

But in addition, the nature of that injectate poses, kind of engineering considerations, you know, such as corrosivity, at -- and additional correlative rights risks.

So -- so it -- based on those facts or aspects of it, it believes that there's those additional consideration and level of scrutiny needed to elevate it to the Commission level of consideration.

Q And in conclusion, Mr. Rose-Coss, is in your

opinion, the Pinon Application adequate as you reviewed it to address OCD's concerns with waste, correlative rights, and protection of public health in the environment?

A It is.

Q Thank you.

MR. TREMAINE: No further questions.

CHAIR SANDOVAL: Mr. Rankin, do you have any questions for the witness?

MR. RANKIN: I do not.

CHAIR SANDOVAL: Commissioner Bloom?

COMMISSIONER BLOOM: No questions, Madam Chair. Thank you.

CHAIR SANDOVAL: Okay. I have a handful of questions.

Mr. Rose-Coss, are you familiar with, let's see, the Geolex presentation that was presented today?

THE WITNESS: Yes, Madam Chair. I am.

CHAIR SANDOVAL: On slide 41, so it just calls out the injection wells in the vicinity of the proposed AGI. There are seven wells, I think within eight miles of this proposed AGI.

Are there any concerns with interactions between these wells?

THE WITNESS: You know, I believe that the concerns that there would be, are addressed in -- in their modeling that they presented today.

So the Division appreciates that all of those wells were incorporated into the model. And that the model was generated, running those wells at, you know, the model was generated conservatively.

So all of those wells were run at higher rates presumably, potentially than they actually are going to be operated at.

And -- and so, the -- the modeling performed puts to rest many of the concerns, if not all of them, regarding those wells in the area.

CHAIR SANDOVAL: Okay. Most of them look like they're a ways away. It was, let's see, 30-025-25046 that's relatively close by.

But the Division, based on the modeling, doesn't have any concerns? I mean, that's the West Jal B Deep Number 1.

THE WITNESS: Yeah. You know, the Division would have more concerns -- it would have significant concerns regarding the permitting additional wells in the area.

So any applications up for review within a broad AOR, or receive strict scrutiny, the

West Jal B Deep is existing.

And based on the modeling, the modeling suggests that both of these wells can co-exist at -- at their proposed rates.

CHAIR SANDOVAL: Okay. So if the Division were to get -- well, maybe -- so these are the existing wells. Do you know if there are any proposed wells nearby, like that are in application?

THE WITNESS: There aren't proposed -- there aren't proposed wells that are near approval. And -- and anything in the area -- it's -- it's not the most popular area for SWD applications.

So -- so they have -- they have staked their claim here to -- to this -- this kind of 3 miler.

CHAIR SANDOVAL: Okay. But so if the Division were to get applications in within the area of review for this AGI, would there be additional scrutiny on those applications for potential interference, or how would that be handled?

THE WITNESS: You know, any -- anything within a mile and half of this well, wouldn't be permitted in the radius of this well. And -- and anything within a 3 miles radius, I would say.

You know, the -- the other flag that comes up in this instance, is the proximity to faults. And structure in the basin. And so it is on the eastern portion of what's considered like, the major Delaware Basin.

So you know, moving east, all of those wells focus -- there was additional kind of, review in regards to any seismicity concerns.

So fault slip modeling will be a bare minimum. Anything that's within 3/4 of mile of one of these -- faults, requires a large additional scrutiny.

CHAIR SANDOVAL: Okay. So you mentioned a meeting with Pinon and talking through some other divisions' concerns, were there any modifications that came out of the meeting?

Was there any change to the Application, or change to conditions, or any -- anything that came as a result of that meeting?

THE WITNESS: No. Nothing major came out of that meeting. Just kind of assessing the -- kind of the state of their modeling is -- is really what came out of it.

And Pinon and Geolex was just forthcoming with kind of how they put together the model and what they were going to present here today.

So I believe, so you know, the only additional things that came up that I believe were addressed by Mr. Ampomah and Mr. White, was the way that the faults were modeled within their simulation.

And so -- so those were discussed before the -- the Commission.

CHAIR SANDOVAL: Okay. And the Division is not recommending any additional conditions or modifications to the current Order other than -- where you're eventually updating the limit per day, but nothing else?

THE WITNESS: You know, the Division was happy to see the additional scrutiny provided by the Commission, and through the modeling, to validate the request for the additional injection.

And was happy to see all of the additional information provided to justify their request.

And believes that future modifications are, you know, significant. Major modifications to the well, or to this injection limit, should again, come before the Commission.

But beyond that, we did not oppose the application. But we -- we would suggest -- it would be nice that because Geolex is going to be updating

the model periodically, as per the conditions of approval of the initial Order, that the considerations raised by Dr. Ampomah are considered and incorporated into future models as they gain more information and have more injection history done. History match their modeling.

CHAIR SANDOVAL: Okay. So when somebody comes in for a modification of an application, or modification of the existing order with a new application, such as today, does the Division do a compliance review of the well that is being modified?

THE WITNESS: Yes, Madam Chair.

CHAIR SANDOVAL: And have they complied with all the requirements so far of this well?

THE WITNESS: Yes, Madam Chair. As -- as far as the current status of both of the wells, the -- the redundant well as well, Geolex and Pinon have been in compliance.

CHAIR SANDOVAL: Okay. For the other, I think it was in Exhibit 2 by the Division, and some of the other AGIs, so it's the Division's practice to require a redundant well.

Is kind of the injection patter here, similar to other wells where they're intending to use

both wells simultaneously?

Or is that unique to this scenario, and most just use one?

THE WITNESS: You know, a review of this list -- you know, one of the things that I think it does is illustrates the kind of chronology of the Division's history with these, and they increase in complexity in kind of learning curves that the Division's gone through.

And so having a redundant well is a new phenomenon based on previous learnings with the Division.

And so the other case that I'm most familiar with in which a redundant wells is used, the redundant well's in the Delaware Mountain Group.

And so there's additional concerns regarding the Delaware Mountain Group. And so my understanding was that that well wasn't going to be -- that well was going to be used as a backup in case one goes out of commission.

And then only use that to avoid the kind of corelative rights risk associated with creating a large acid gas plume in the Delaware Mountain Group.

And so we're -- the Division is -- has

less concerns with the redundant wellbeing in the Devonian in this case, and the wells being utilized in that manner.

CHAIR SANDOVAL: Okay. So the Division is comfortable with both wells being used at the same time as long as it doesn't exceed the 20 million a day?

THE WITNESS: Yes. Yes.

CHAIR SANDOVAL: All right. I think that was my last questions. Mr. Tremaine, do you have any follow-up with the witness?

MR. TREMAINE: No, Madam Chair. Thank you.

CHAIR SANDOVAL: All right. Thank you, Mr. Rose-Coss. You are dismissed.

THE WITNESS: Thank you, Madam Chair. Thank you, Commission.

CHAIR SANDOVAL: Mr. Rankin, do you have any brief closing statements?

MR. RANKIN: Thank you for the opportunity, Madam Chair.

CLOSING STATEMENT

MR. RANKIN: The only thing I will say is we appreciate the Commission's time and attention during the fairly technical presentation today.

And we appreciate the questions, and concerns, and focus on safety, health, and concerns around correlative waste, and -- correlative rights, and prevention of waste.

But no additional comments other than to say, you know again, we appreciate the Commission's attention and consideration.

And we ask that this Application be approved with the existing conditions under the existing Order.

CHAIR SANDOVAL: Thank you, Mr. Rankin. Mr. Tremaine, do you have any closing statements?

MR. TREMAINE: Very briefly, Madam Chair.

CLOSING STATEMENT

MR. TREMAINE: The Division asks that the Commission consider the Petition that the Division outlined today.

And should the Commission approve the Application of Pinon, that you do so in a manner that's consistent with the Order to be amended in terms of the other conditions and requirements.

Such as leaving in place, deadlines for the completion, and injection deadlines for the redundant well, and the various other requirements.

The Commission may consider Mr. Rose-Coss' recommendation of considering updates to the modeling as they're available through -- through Pinon.

But other than that, the Division does not have any other objections, or items to raise regarding the Application. Thank you.

CHAIR SANDOVAL: Thank you Mr. Tremaine.

MR. MOANDER: Madam Chair, before you close up everything --

CHAIR SANDOVAL: Yeah.

MR. MOANDER: -- just because you've not closed the evidentiary record yet.

I just want to clarify with the parties because we heard some pretty hefty technical stuff today.

That the focus of this whole hearing, and I'm going to say this and hopefully not screw this up, is purely to address the MMSCFD from Order R-21455-A.

And basically changing the language in that Order, modifying from 12 million to 20 million. There's no other changes that are being requested specifically. Is that right?

And either party can answer at any point. I just want to make sure we're clear on all the concepts here, so there's no vagueness or errors.

MR. RANKIN: Madam Chair, if I may just make one additional clarification from Mr. Moander's statement.

CHAIR SANDOVAL: Go ahead.

MR. RANKIN: The only, I guess, slight modification there would be that the requested increase in injection rates would be applicable to not just the AGI 1 but would be to both wells.

So the way the Order reads now is that it's applicable to the AGI 1. And so we want to make clear that the amendment isn't for allowance of the 20 million standard cubic feet per day into both wells. Combined total.

CHAIR SANDOVAL: So a maximum between -- just to be explicitly clear. A maximum between the two wells, is 20 total. We're not talking 40?

MR. RANKIN: Correct.

MR. TREMAINE: And, Madam Chair, in response to that. What Mr. Moander outlined is consistent with the Division's perspective.

The Division's primary concern here was

making sure that the technical basis, primarily the modeling, but the entire technical basis that was the justification for the previous Order, was updated to reflect the additional injection amounts.

And so that's why we have very narrowly focused the presentation here today on OCD's review of that modeling and kind of that process.

So our understanding is, Mr. Moander, is that yes. That is correct. It is that one change.

And that to clarify, OCD's previous statements, or mine, it references to like, major modifications.

Should in the future, Pinon ask for an increased injection, you know, the technical basis for this hearing, and any subsequent order, would be a technical basis to justify 20 million standard cubic feet per day, not something in excess.

So that's why OCD's drawn that distinction that, you know, future major modifications, such as another increase in injection, OCD asks that, consistent with the existing Order, those changes like that, come back before the Commission.

MR. MOANDER: Thank you gentleman. Because nothing will complicate one of these issues

more than lawyers and engineers talking to each other. So I appreciate the clarification.

CHAIR SANDOVAL: Any other questions, Mr. Moander?

MR. MOANDER: No, Madam Chair. Thank you for indulging me.

CHAIR SANDOVAL: All right. The record of this hearing is now closed.

The Commission will immediately deliberate so as to reach a final decision on the Application.

I move that the meeting be closed pursuant to the Administrative Adjudicatory Deliberations Exception to the Open Meetings Act Section 10-15-1(h)(3), to deliberate in this case.

Is there a second to my motion?

COMMISSIONER BLOOM: Madam Chair, I second.

CHAIR SANDOVAL: Mr. Moander, would you please do a rollcall vote?

MR. MOANDER: Happily. Commissioner, Bloom?

COMMISSIONER BLOOM: Approve.

MR. MOANDER: Madam Chair?

CHAIR SANDOVAL: Approved.

MR. MOANDER: The motion carries. And this hearing is now closed for deliberations.

CHAIR SANDOVAL: Okay. Everybody can remain --

THE REPORTER: Going off the record at 1:34.

(Off the record.)

CHAIR SANDOVAL: Okay. It is two o'clock. And the -- let's see.

The Commission Meeting on the record is now open.

And the discussion during the closed session was limited to deliberations in Case Number 22977. I move to go back on.

MR. MOANDER: Madam Chair, I have, and I think you should probably also note that Dr. Ampomah did not participate in, was not involved in deliberations.

CHAIR SANDOVAL: Thank you. And during the session, the conversation was limited to deliberations in Case Number 22977 and the only participants were myself, and Commissioner Bloom, and counsel of the Commission was present.

Dr. Ampomah did not participate in deliberations or discussion.

And with that, I would move to go back on -- or to reopen the Meeting. Let's see, as it was closed with the deliberations exception to the Open Meetings Act Section 10-15-1(h)(3).

Is there a second?

COMMISSIONER BLOOM: Madam Chair, I second.

CHAIR SANDOVAL: Mr. Moander, would you do rollcall please?

MR. MOANDER: Yes, Madam Chair. Commissioner Bloom?

COMMISSIONER BLOOM: Approve.

MR. MOANDER: Madam Chair?

CHAIR SANDOVAL: Approved.

MR. MOANDER: Motion carries.

CHAIR SANDOVAL: All right. Great. Thank you. All right.

So in Case Number 22977, I move to increase the injection rate to a combined total of 20 million standard cubic feet per day, that is shared between AGI well #1 and AGI well #2.

The Commission is to retain authority for any major modifications to a future application.

And then the Commission would also -- I move to also add a condition that has been in some

previous AGI Orders prior.

Such as AGI Order R-20694, and which shall state,

"The Operator shall, every two years, once injection begins, provide the Division with a report that compares the reservoir pressures, volumes injection, and projected TAG plume extent to those estimated in the C-108 Application.

Together, with summarizing the AGI wells' performance, including but not limited to, injected volumes by fluid type and reservoir pressure.

And potential calibration of models due to information collected during the prior two year period.

Ameredev, I think in this case, will use data collected and analysis conducted pursuant to this Order, to prepare the analysis.

The report shall include an updated model of current and projected plume migration, and shall use the modeling technology, and standard use at the time of the report, and any available information about plume migration.

At the request of the Commission, the Operator shall provide in person presentations of its data and analysis regarding the AGI wells'

performance.

And the inclusion of this is due to the proximity of several other injection wells within the area and within the potential plume.

To determine how those interact with one another over time and if the modeling that was based on these initial parameters remains accurate."

And with that motion, is there a second?

COMMISSIONER BLOOM: Madam Chair, I think I heard you mention Ameredev in the middle of that. Did you mean Pinon?

CHAIR SANDOVAL: I did.

COMMISSIONER BLOOM: Okay. And so we'll, yeah. We'll make sure to make that change there.

MR. MOANDER: Is the --

COMMISSIONER BLOOM: And what is that modification?

MR. MOANDER: Is the motion modified, Madam Chair?

CHAIR SANDOVAL: Yes.

MR. MOANDER: Okay. So now, we're back on track. So back to Commissioner Bloom.

COMMISSIONER BLOOM: All right. So we

modified to motion to include the mention of Pinon, striking Ameredev.

And I second this motion, Madam Chair.

CHAIR SANDOVAL: Would you please do a rollcall vote, Mr. Moander?

MR. MOANDER: Happy to do so, Madam Chair.

Commissioner Bloom?

COMMISSIONER BLOOM: Approve.

MR. MOANDER: Madam Chair?

CHAIR SANDOVAL: Approved.

MR. MOANDER: The motion carries.

CHAIR SANDOVAL: Okay. Mr. Moander, would you please update the Order, and then provide the Order for final vote at our October 13th Commission meeting?

MR. MOANDER: Yes, ma'am.

CHAIR SANDOVAL: Thank you. And with that, is there an update on any pending litigation?

MR. MOANDER: Believe it or not, there is a little bit.

I checked on A1CA39578, which is the Barker appeal. The Court has not taken any action since February. I'm not sure what's going on. I think I'm going to -- I'll take a deeper look at that.

The other case is the Ragsdale District Court Rule 70 -- appeal. The reply by Ragsdale was filed late yesterday, which completes the open briefing cycle agreed to by the parties.

And Ragsdale should be -- counsel for Mr. Ragsdale should be submitted for hearing in anticipation of briefing today.

So I anticipate a hearing of some sort likely to be set probably in the next 30 to 45 days.

CHAIR SANDOVAL: Thank you. Is the any other business before the Commission today?

All right. Our next meeting is October 13th, and we will see many of you there. Thanks everybody. And have a great rest of your day.

UNIDENTIFIED SPEAKER: Thank you all. Appreciate it. Take Care.

THE REPORTER: Going off the record at 2:07 p.m.

(Whereupon, at 2:07 p.m., the proceeding was concluded.)

CERTIFICATE OF DEPOSITION OFFICER

I, BRETT TORRENCE, 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.

BRETT TORRENCE
Notary Public in and for the
State of New Mexico

CERTIFICATE OF TRANSCRIBER

I, CHRISTINA KNOTE, do hereby certify that this transcript was prepared from the digital audio recording of the foregoing proceeding, that said transcript is a true and accurate record of the proceedings 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.

CHRISTINA KNOTE