STATE OF NEW MEXICO

ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTTER OF THE HEARING CALLED
BY THE OIL CONSERVATION DIVISION FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 20779

APPLICATION of LUCID ENERGY DELAWARE, LLC,
FOR AUTHORITY TO INJECT, LEA COUNTY,
NEW MEXICO

REPORTER'S TRANSCRIPT OF VIRTUAL PROCEEDINGS
SPECIAL HEARING OF THE OIL CONSERVATION COMMISSION

(Agenda Item 4)
THURSDAY, SEPTEMBER 3, 2020
SANTA FE, NEW MEXICO

BEFORE: ADRIENNE SANDOVAL, COMMISSIONER CHAIR
THOMAS ENGLER, PhD, COMMISSIONER
NIRANJAN KHALSA, COMMISSIONER
MIGUEL LOZANO, ESQ., COMMISSION COUNSEL

This matter came on for virtual hearing before the New Mexico Oil Conservation Commission on Thursday, September 3, 2020, through the New Mexico Energy, Minerals and Natural Resources Department Webex Platform, Santa Fe, New Mexico

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OIL CONSERVATION DIVISION EXHIBITS

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(Time noted 10:15 a.m.).

COMMISSION CHAIR SANDOVAL: This is a hearing in Case No. 20779 to consider the Application submitted by Lucid Energy Delaware, LLC for authorization to inject acid gas and carbon dioxide into Proposed AGI2 well.

The Oil Conservation Division per timely Notice has intervened for the purposes of this hearing.

Will the parties please make their appearances for the record, beginning with the Applicant.

MS. HARDY: Good morning, Commissioners and Madam Chair. Dana Hardy with the Santa Fe office of Hinkle Shanor on behalf of Lucid Energy Delaware, LLC.

MS. BADA: Good morning, Madam Chair and Commissioners. This is Cheryl Bada with the New Mexico Energy and Minerals and Natural Resources Department on behalf of the Oil Conservation Division.

COMMISSION CHAIR SANDOVAL: Thank you. This hearing will be conducted in accordance with the Commission's adjudication rules, as well as Special Procedural Rules set by Commission Order issued on August 4, 2020. This hearing will be heard in a fair and impartial manner so as to ensure that the relevant facts are fully elicited and to provide a reasonable opportunity for all interested persons to be heard.

The hearing shall proceed as follows:

All testimony will be taken under oath. I will admit any relevant evidence unless I determine that the evidence is unduly repetitious, otherwise unreliable, or of little probative value.

Any party who wishes to make a brief opening statement before presentation of his or her direct testimony may do so.

The Applicant will present direct testimony first. Other interested or intervening parties who have standing and who filed a timely prehearing statement or Notice of Intent to Present Direct Testimony, may present direct testimony.

Any party to this hearing may cross examine witnesses. Only the commissioners and participating parties shall have the right to cross examine a witness. Cross examination by other parties will be conducted at the conclusion of each presentation followed by cross examination by the Commission.

Redirect examination will be permitted but such testimony is limited to testimony relevant to that offered during cross examination. If time permits and at my sole discretion, a party who wishes to give rebuttal testimony or make brief closing arguments may do so at conclusion of the testimony in the same order as the direct testimony.

Any objection concerning today's conduct of today's hearing may be stated orally during the hearing with the party raising the objection briefly stating grounds for the objection.

The ruling I make on any objection and the reason will be stated for the record.

We will now proceed with the hearing.

Is there any admission of evidence or facts stipulated by the parties?

MS. HARDY: No, Madam Chair.

MS. BADA: This is Cheryl Bada. No, Madam Chair.

(Note: Pause.)

COMMISSION CHAIR SANDOVAL: The Applicant may make a brief opening statements.

MS. HARDY: Thank you Madam Chair.

Lucid requests authorization to inject treated acid gas from its Red Hills Gas Processing Plant into the Red Hills AGI2 well, which will be located in Section 13, Township 24 South, Range 33 East in Lea County.

Lucid seeks approval to drill and complete the well for the injection of TAG into the Devonian/Upper Silurian Formations at depths of approximately 16,000 to

17,600 feet.

Lucid currently operates the Red Hills AGI1 at the Red Hills plant, and the proposed Red Hills AGI2 will allow Lucid to expand its treatment capacity while also serving as a redundant well. The wells will also provide for environmental benefits, including the sequestration of CO2 and potential emissions credits.

Lucid's witnesses will include Matthew Eales, David White, Alberto Gutierrez, and William Ampomah. As Lucid's witnesses will explain, the proposed well will protect human health and the environment, and will not result in waste or impair correlative rights.

Lucid has also agreed with OCD's recommended approval by the Commission.

For these reasons and the reasons that will be explained by Lucid's witnesses, Lucid requests that the Commission grant this application.

Thank you.

COMMISSION CHAIR SANDOVAL: Thank you.

The Division may make an opening statement if they choose to do so, or may do so at the beginning of your presentation.

MS. BADA: We just have a brief comment that we don't oppose this application, Madam Chair and Commissioners, as long as the Commission adopts the conditions proposed by the Division.

COMMISSION CHAIR SANDOVAL: Thank you, Ms. Bada. The Applicant may now present its direct testimony regarding its application. Each witness will be sworn in at the beginning of his or her testimony.

Ms. Hardy, would you please call your first witness.

MS. HARDY: Yes, Madam Chair. Lucid's first witness is William Eales.

COMMISSION CHAIR SANDOVAL: Since I think the court reporter is struggling to speak, Mr. Eales, I'll present you with the oath.

ROBERT MATTHEW EALES,

having been duly sworn, testified as follows:

COMMISSION CHAIR SANDOVAL: Thank you.

Please proceed, Ms. Hardy.

MS. HARDY: Thank you.

And Madam Chair, I was planning to share my screen for some of the exhibits. I don't have to, but that would be under my name, not the conference room, and I can't seem to do that.

COMMISSION CHAIR SANDOVAL: Do you want to use it under your name?

MS. HARDY: Yes. I'll leave myself muted because I'm using our conference room audio, but if I could share my laptop screen.

COMMISSION CHAIR SANDOVAL: Try it now.

MS. HARDY: It is working now.

COMMISSION CHAIR SANDOVAL: Okay. Great.

MS. HARDY: Let me get it up here.

DIRECT EXAMINATION

BY MS. HARDY:

Q.   Good morning, Mr. Eales.

A.   Good morning.

Q.   Would you please state your full name.

A.   My full name is Robert Matthew Eales.

Q.   Where do you reside?

A.   Prosper, Texas, and Artesia, New Mexico. Split between the two.

Q.   By whom are you employed and in what capacity?

A.   Lucid Energy Group as the VP of environmental, health safety, and regulatory.

Q.   What are your responsibilities in that position?

A.   Inclusive in that may be OCD compliance, employee safety and pipeline.

Q.   Have you ever testified at a commission hearing?

A.   No.

Q.   Given that, would you please summarize your educational and professional background.

A.   I have a Master's degree in environmental engineering from the University of Kansas. I've been employed in the oil and gas industry for 23 years in various environmental leadership roles, primarily with Slumberger and Global Western Hemisphere. Environmental roles. And in other oil and gas companies upstream, and now with Lucid.

MS. HARDY: Madam Chair, based on Mr. Eales' education and professional experience, I tender him as an expert in environmental engineering.

COMMISSION CHAIR SANDOVAL: Any objection, Ms. Bada?

MS. BADA: Madam Chair, Commissioners, no objections.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have any objectionS?

COMMISSIONER ENGLER: No objection.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: Thank you. The witness is certified as an expert. Please proceed.

MS. HARDY: Thank you.

Q. Mr. Eales, can you please identify Lucid Exhibit 1.

A. Yes. Lucid Exhibit 1 is our C-108 Application.

Q. Is Exhibit 1 a true and correct copy of the Application?

A. Yes.

Q. Did Lucid retain Geolex to prepare its C-108?

A. Yes, we did.

Q. Were you personally involved in Geolex's presentation, preparation of the Application?

A. Yes.

Q. And did Mr. Gutierrez and Mr. White testify regarding the application?

A. Yes.

Q. In addition to Geolex, did Lucid retain New Mexico Tech to provide an analysis regarding Lucid's application?

A. Yes, we did.

Q. What does that analysis include?

A. That includes the potential for any new seismicity.

Q. Will Dr. Ampomah discuss that analysis in his direct testimony?

A. Yes, he will.

Q. Mr. Eales, can you please identify the document marked as Lucid Exhibit 2.

A. Yes. That's our Lucid Business Overview.

Q. And was this overview prepared by you or under your supervision?

A. Yes, it was.

Q. Can you please describe what is shown on Slide 2 that I have put up on the screen.

A. Yes. Slide 2 is, as it states at the top in the title, is an overview of our operations, separated into sections, as well as our client base.

Overall Summary is self explanatory. Some bullet points on where we're at as a company. At the bottom left an overview of our assets, including the pipeline and the compression.

At the top right a map of the overall asset base, and particularly where we have our gas processing plants, including Red Hills in the bottom-right corner, and, as I said earlier, our list of selective (Inaudible).

Q. Mr. Eales, can you please describe what's on Slide 3.

A. Yes. This slide is an overview of our evolution since Lucid's acquisition of Agave, and our growth since then. So it shows the expansion timelines since '17, volumes added. And the bright shows the difference of our footprint at the time to the footprint today.

Q. Can you please explain what's shown on the next slide.

A. Yes. The intent of this slide is to show our volume growth in natural gas processed within New Mexico up until Quarter 3. So you will see the growth, and especially the stair-step growth related to the commissioning of individual trains at Road Runner and Red Hills.

Q. Can you explain what's shown on Slide No. 5.

A. Yes. Primarily it's an aerial photograph of our Red Hills gas processing plant. Since this photo was taken we've added a control room to the right of the red area to run all of the trains from one location.

You also see the AGI well, AGI1 as we call it, in the far distance just to the right of the table.

You also see the nameplate capacity with each of our trains. And again each one those of when commissioned brought us up to 1.16 billion assets.

Q. Is Lucid currently operating the Red Hills AGI1?

A. Yes, we are.

Q. Was authorization to inject into that well initially granted to Agave Energy?

A. Yes, it was.

Q. And when, approximately, was that?

A. It was approximately January, 2012.

Q. Can you provide a brief summary of the history of the Red Hills plant and the AGI1 well?

A. Absolutely. The Red Hills No. 1 plant, as noted earlier, was commissioned, permitted under Agave, went into service September of 2013. And previous slides and the next slide will actually show the timeline in more detail for the Commissioners.

Q. Let's look at that slide, please.

A. The timeline for the train additions is shown here: Expansion for the Red Hills 1, 2, 3 and the incremental volumes brought on. You will see the final incremental volume is -- uhm, covered up by the graph. So it's that 1.16 -- and how each one of these trains added to it over the years.

And we've also provided the details of each one of those trains for commissioners' viewing.

Q. What is the Red Hills plant current capacity for processing sour gas?

A. It's current capacity for processing is 1.1.

Q. Is Lucid planning plan to expand that capacity?

A. Yes, we are.

Q. Why is that?

A. Upstream customer-communicated needs. We continue to see a need to expand into where we have currently permitted the seven trains with our effort.

Q. How large is the site where the processing plant is located?

A. 300 acres.

Q. Can you please describe what's shown on the next slide, No. 7.

A. Yes. This is an overview of our current AGI1 as well as an overview of intent with AGI2.

As noted in previous photo, this is an aerial photo of our current operations. It's currently running close to design; we have a need to expand.

You'll note the design basis and our actual statistics in the tables at the far left, and our proposed expansion.

The bottom bullet points, far left, AGI is currently taking 2.49 million cubic foot of gas a day, 85 percent CO2, 15 percent H2S. AGI2 is projected to take 9600 mmcf, 94 percent CO2 and 6 percent H2S.

Q. Does Lucid intend to simultaneously operate the Red Hills AGI1 and the Red Hills AGI2 wells?

A. Yes, we do.

Q. When was the AGI1 well drilled?

A. It was drilled in 2013.

Q. And that well's currently operating?

A. That's correct.

Q. What is the volume of treated acid gas that Lucid currently injects into the Red Hills AGI1.

A. 2.491 million cubic feet per day.

Q. And what is the volume of TAG that Lucid plans to inject into the Red Hills AGI2?

A. 9.6 million cubic feet per day.

Q. Mr. Eales, let's talk about the environmental benefits in the injection of treated acid gas. Can you summarize those benefits?

A. Yes. The intent of an AGI well is actually fully for the benefit of the environment. AGI wells were put into place as a preferred method for disposing of acid gas rather than flaring, and the SO2 and the safety risk associated with that.

In addition to that, we, as noted earlier, are injecting CO2. We are actively working in project to continue to inject the CO2 and to get 45Q certification for that injection, once we're able to document with an MRV that we've got full capture of the TAG.

Q. And without an AGI well, how would oil and gas operators treat their -- dispose of their sour gas?

A. Our operator clients would have to flare the H2S sour gas.

Q. Does the injection of TAG eliminate flaring at the plant as a control for sulphur derived in the processing of sour gas?

A. Yes, it does.

Q. And does it eliminate the need to vent CO2?

A. Yes, it does.

Q. Will the injection of TAG minimize CO2 emissions from the plant?

A. Yes, it will.

Q. In your opinion will there be environmental benefits if Lucid is authorized to inject CO2 in the Red Hills AGI2 well?

A. Yes. Benefits would, as noted earlier, benefit Lucid as well as minimize flaring upstream.

Q. And will Lucid be in a position to obtain emission credits?

A. We are hoping so. We are very optimistic that we will.

Q. Will Lucid complete an H2S contingency plan before commencing injection into the well?

A. Yes, we will.

Q. In your opinion will that plan comply with all the Commission's requirements for H2S?

A. Yes, it will.

Q. Mr. Eales, have you reviewed the Oil Conservation Division's recommended approval of the well?

A. Yes, I have.

Q. I think those have been identified, although they haven't been introduced yet, as OCD Exhibit 1.

A. Yes.

Q. Does Lucid accept those conditions?

A. Yes, we do.

Q. Mr. Eales, in your opinion will the ability to

inject acid gas into the well --

COMMISSION CHAIR SANDOVAL: Ms. Hardy --

MS. HARDY: Yes.

COMMISSION CHAIR SANDOVAL: -- the court reporter is struggling to hear.

We can hear you pretty well.

Ms. Macfarlane, I would recommend you turn the volume up all the way. We seem to be able to hear okay.

MS. HARDY: I'll try to speak up.

COMMISSION CHAIR SANDOVAL: Thanks.

MS. HARDY: Thank you.

Q. (Repeated) Mr. Eales, in your opinion will the ability to inject acid gas into the well result in more efficient operation of the Red Hills plant?

A. Yes, it will.

Q. And in your opinion will Lucid's proposed method of disposing of acid gas protect public health and the environment?

A. Yes, absolutely it will.

MS. HARDY: Madam Chair, I move the admission of Lucid Exhibits No. 1 and 2.

COMMISSION CHAIR SANDOVAL: Any objection, Ms. Bada?

MS. BADA: Madam Chair, no objections.

COMMISSION CHAIR SANDOVAL: Commissioners, any objections?

COMMISSIONER ENGLER: No objection.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: No objections from the commissioners, and Lucid Exhibits 1 and 2 are entered into the record. Please proceed.

MS. HARDY: Thank you. I have no further questions for Mr. Eales. He is available for questions from the commissioners and counsel.

MS. BADA: Madam Chair, this is Cheryl Bada. The OCD has no examination for this witness.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have any questions for the witness?

COMMISSIONER KHALSA: No questions.

COMMISSIONER ENGLER: Yes. This is Tom Engler. I've got one quick question. Appreciate the work.

CROSS EXAMINATION

BY MR. ENGLER:

Q. My question is: If the AGI2 is approved, will the AGI1 still be operating?

A. Yes, it will.

Q. So the expectation is that both will be able to inject simultaneously.

A. That's correct.

COMMISSIONER ENGLER: All right. Thank you. That was my question.

THE WITNESS: Thank you.

CROSS EXAMINATION

BY COMMISSION CHAIR SANDOVAL:

Q. Mr. Eales, so just along those lines, if one of the AGIs is down, would there always be a backup?

A. That's correct.

COMMISSION CHAIR SANDOVAL: Okay. Thank you.

Any questions?

Okay. No further questions, Ms. Hardy.

MR. EALES: Thank you.

MS. HARDY: Thank you, madam Chair. Lucid's next witness is Mr. Alberto Gutierrez.

Let me make sure he's -- he should be here in just one second. Thank you.

COMMISSION CHAIR SANDOVAL: No problem.

MS. HARDY: Thank you. (Note: Pause.)

My apologies, Madam Chair. Let's me make sure he's -- I hear him coming.

COMMISSION CHAIR SANDOVAL: No problem.

MS. HARDY: So there he is.

MR. GUTIERREZ: Sorry. I had to find this room here.

MS. HARDY: Do we need to swear the witness?

COMMISSION CHAIR SANDOVAL: Yes. I think I will do that again.

ALBERTO GUTIERREZ,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. HARDY:

Q. Good morning, Mr. Gutierrez.

A. Good morning.

Q. Can you please state your full name.

A. Alberto A. Gutierrez.

Q. Where do you reside?

A. Albuquerque.

Q. What is the name of your company?

A. Geolex, Incorporated.

Q. In what capacity do you serve?

A. I am the president of the company and I'm a geologist.

Q. Please summarize your educational and professional background.

A. I'm a professional geologist. I have been -- I have a Bachelor's and Master's degree in geology from -- Maryland is my Bachelor's, from UNM my Master's -- back in 1979, '80, and I've been practicing in this field since that time.

Q. Did you prepare Lucid's C-108 Application?

A. Yes.

Q. Have you prepared other applications for approval to inject acid gas?

A. Yes. In fact I prepared the applications for pretty much every well except one in New Mexico.

Q. Did you testify at the hearings on each of those applications?

A. I did.

Q. Were you qualified as an expert petroleum geologist and hydrogeologist?

A. Yes, I was.

MS. HARDY: Commissioners and Madam Chair, I tender Mr. Gutierrez as an expert in petroleum geology and hydrogeology.

COMMISSION CHAIR SANDOVAL: Any objection, Ms. Bada.

MS. BADA: Madam Chair, no objections.

COMMISSION CHAIR SANDOVAL: Commissioners any objections?

COMMISSIONER ENGLER: This is Tom Engler. No objection.

COMMISSIONER KHALSA: Commissioner Khalsa. No objections.

COMMISSION CHAIR SANDOVAL: Okay. And the witness is certified as an expert. Please proceed.

MS. HARDY: Thank you. I'm going to share my screen here.

And Madam Chair, I wanted to mention that Mr. Gutierrez will address a significant part of the presentation, and then we'd like to have Mr. David White address a couple of topics, and in the end of the Geolex portion bring Mr. Gutierrez back to address the final conclusions.

Is that acceptable to the Commission?

COMMISSION CHAIR SANDOVAL: Yeah, that's fine. I would just add, Ms. Hardy, if you could, when you're speaking, speak as much into kind of straight forward into your screen. It looks like we pick up your sound better.

MS. HARDY: Okay. Thank you.

Q. Mr. Gutierrez, can you please identify Lucid Exhibit 3.

A. Let me get that. It is the presentation that we are about to look at here.

Q. Was the presentation prepared by you or under your direct supervision?

A. It was.

Q. Will Mr. White also testify regarding portions of the presentation?

A. Yes. As a matter of fact, I think on the next page we kind of describe what each of the witnesses is going to talk about. So I can kind of give a little overview of how we're going to set the presentation up. We can go through it.

Q. Did you also prepare Lucid's C-108, which is marked as Lucid Exhibit 1?

A. I did. Both David and I did, and we worked also in conjunction with William.

Q. Is the C-108 true and correct to best of your knowledge?

A. It is. It's been supplemented by additional work which will be described by Dave and Willie.

Q. Thank you. And can you describe the presentation topics overview for each witness?

A. Sure. Mr. Eales has already done his presentation. I'm going to go through the bulk of the geologic and hydrogeologic analysis, the design, the proposed designs for the well, and the original analysis on the injection zone, and as a -- in order to accommodate the Commission's desire to have a more robust seismicity assessment and more robust modeling of the plume migration and plume evolution over time, we took upon us to do a significantly different kind of modeling, in addition to the simple volumetric modeling that we do in our normal applications.

And, uhm, David will present our modeling results as we have refined our plane volumetric model and the work that he's done to look at seismicity risk and containment in the reservoir, and then Dr. Ampomah, William, will describe -- we worked jointly with New Mexico Tech, and they developed a model using Petrel and Eclipse where we simulated all of the injection in the area, not only from our well but from the surrounding wells, and put them -- the effects of it, both pressure and volume, in terms of the evolution of the plume.

And so William will be describing that, and then I will come back and summarize the over-all.

Q. Can you please describe the key elements of Lucid's C-108.

A. Sure. Basically the AGI project has substantial environment benefits because a significant amount of the stream which is being injected now, and an even more significant amount of the stream which will be injected into the Red Hills No. 2 is CO2, which would otherwise be released into the atmosphere, and is going to be permanently sequestered, in this case in the Devonian.

The AGI project reduces waste and air emissions by eliminating the flaring of acid gas for the operation of a salt water recovery unit, which is the other primary mechanism for getting rid of acid gas, which are notoriously difficult to operate and keep under air regulation constraints.

Also nearby oil and gas wells and water wells and surface water are protected by both the well design and geologic factors associated with the reservoir, which we will talk about.

Similarly overlying fresh water resources, other nearby salt water disposal wells and producing wells will all be protected by the accurate delineation of the reservoir and what wells we have, designs that we're evaluating and will use for the AGI2 well.

The application details all of the information necessary to approve the installation of the well. When the original application was developed and submitted, it was prior to the hearing that we had with the Commission for the Three Bear AGI, which is when the commissioners made it clear that they wanted to see a little more sophisticated modeling to evaluate the plumes. And so in the original C-108 we had only the single volumetric model which I'll go over, and then we refined that in the subsequent information that was submitted later.

The adjacent operators and the OCD and the BLM all prefer deeper injection in terms of the Devonian vs. the DMG in the area, so that's another reason why we went for that reservoir, which is quite deep in this area.

Operators and the surface owners have received proper Notice. And there were some original concerns on behalf of a couple of operators. We met with them and with OCD and we've resolved those concerns, so now the operators in the area support the project.

Q. Mr. Gutierrez would you please provide some information regarding the location and background.

A. Sure. If we can go to the next slide I can use the map. This is just a very large-scale map, but it shows you that the plant is located in Section 13, Township 24 South, Range 33 East in Lea County; that's just off of Highway 128 there from Jal to Carlsbad. And when it's fully operational the plant will produce approximately, or process approximately 1.4 billion cubic feet a day of natural gas, which will make it the largest single plant in the state.

The production will provide additional revenue to the state because of being able to put wells on line that currently aren't on line. So it's a good project.

If we again show the next slide, we can give you an overview of what the plant looks like. Actually, this is an older photograph; I think the ones that Mr. Eales showed are a little more contemporary. But you can see where the existing AGI1 and the proposed AGI2 will be approximately 200 feet north of the existing well.

And those blank pads that you see within the red-outlined area are areas where additional plant equipment "will be" constructed -- at the time of this photograph. A lot of that has already been constructed.

But it is within that boundary that is within the 370 acres or so that Lucid owns out there.

Obviously field gas will be sweetened by the amine units, and the treated acid gas will be compressed and piped to the AGI wells. That's the same thing that's going on now, it will just be on a larger scale with the new train that will feed AGI2.

Q. And what is on Slide 10?

A. This just gives you the legal description of the proposed well where we're anticipating drilling at 1800 feet from the south line, and 150 feet from the east line of Section 13.

It will be a vertical well drilled from that surface location and completed in the Siluro-Devonian Formations below the Woodford, and the new well is approximately 200 feet north of the existing AGI well.

The reason why we want the two wells close together is we want to minimize to the amount of high-pressure acid gas piping on the surface that needs to go from the compression to the two wells, but we need them far enough apart that we can work on one well, if we need to, while the other one is still up. So this will allow us the ability to do that.

Q. Can you please describe the schematics of the well.

A. Sure. If we go to the next slide I can give you a schematic of the surface facilities. This is a very diagrammatic look but basically, as you can see, we've got one shallow well in the DMG that we're currently injecting into. When we drill the deeper Devonian well next to it, it will have a similar kind of construction. Of course it's a much deeper well, and we will go into some of the details of the construction.

But right here on this slide you see an area that is highlighted in green, and that is the portion of the new well that will pass through the zone that we are already using for injection in the old well, and we will protect that by a combination of corrosion-resistant cement and corrosion-resistant casing. We're evaluating two different designs right now, and we can talk about those later in the presentation.

And we had discussed those with the agency, and I think we'll work out a final design with them. It has more to do with the selection of materials in construction to protect the zone of the well where current injection is taking place. And I'll go into some of these details later in the testimony.

But this gives you a pretty good -- and I don't really have a pointer that I can use, but if you look at the upper-right-hand side of the slide, that's where the gas comes into the compression facility, goes through a series of safety valves and controls as it goes out to the individual wells. Then there's obviously pressure control on those wells and monitoring of all of the injection parameters, as well as the annulus and the bottomhole parameters of the wells.

So it's a pretty standard four-string design that we will use for the well.

I think we have covered most of these things in what I've already said, but as I mentioned, this four-string design was -- originally we would have those four strings all cemented to the surface, run to the surface, and in those designs we intend to use -- in either one of the designs we are going to use 300 feet of CRA casing in either the bottom of the tubing and also in the zone where the packer is being put in.

What we're evaluating right now is that in the interval between 6200 and 6700 feet whether we use a design that involves a liner inside the well to go from the, uh packer, from the intermediate down to the, uh, to the production string, or if we run that production tubing all the way to the surface and cement it.

Right now I think that's the design which is being preferred, but we haven't made a final decision on it one way or the other. But both will provide similar or equal protection to the current injection zone of the well as it passes through the current injection.

Q. Can you please summarize the factors that in your opinion will assure safety, integrity of the well?

A. Yes. I mean basically all of the surface and intermediate casing strings will be fully cemented to the surface, will be logged with a circumferential cement bond log before proceeding to the next stream so we will assure that we have a good cement bond between all of the casings and the -- the casing and the surrounding rock.

And then if we go with the liner approach, because we won't have an extra piece of casing within the zone opposite the current injection zone of AGI1, we intended to use CRA casing and corrosion-resistant cement on that intermediate casing string; however, as the designs have evolved and as we've been looking at the relative potential issues with drilling and completion and economics, I think we are leaning more now towards a more traditional AGI design like every other well in this state, where we don't use a liner but we use a production string that is cemented all the way to the surface. And then that would allow us to just use corrosion-resistant cement and HLA casing for the intermediate zone across the injection zone for AGI1.

So I guess in one case you're using the corrosion-resistant casing combined with the cement to provide the added protection in that zone; in the other design you're using a combination of the, uh, corrosion-resistant cement, the HLA casing, and then the borehole for the intermediate casing all the way to the surface.

So those are the two options.

Q. Will there be injection of pressure calculations?

A. Yes. As you may have remembered from Mr. Eales' testimony, he testified that, you know, we only anticipate really putting a little under 10 million a day of TAG into Well No. 2; however, since either one of the wells is designed to be able to be operational if the other one has a problem, we have modeled everything with a very conservative assumption that we're using the full 13 million into the well as an injection stream.

We also -- at the time when the C-108 was conducted, Lucid didn't really have any better information about the composition of the stream than what they're currently injecting, which is roughly about 87 percent CO_2 and about 12 percent H_2S, with some traces of other hydrocarbon.

The proposed additional train is going to be receiving what we believe is a much higher concentration of CO_2 relative to H_2S, so that we wind up with a combined stream that is approximately 94 percent CO_2 and 6 percent H_2S.

But at the time of the C-108 this was the best information we had, and so we modeled everything using this concentration. But one of the things, when we get to that point, that we've done is look at the effect of the new projected concentration for AGI2, and it really has very minimal effects in terms of the modeling. And I'll go into that in a little bit.

We understand that the fluid is compatible with the Formation because we have similar Formation fluid in other Devonian wells nearby where we've been operating very effectively and without any compatibility issue.

Our current MAOP, because the well is so deep, based on the calculation with NMAC guidelines is about 4800, actually 4838 psi at the surface, although we won't ever get anywhere close to that. I think the pressures that we're looking at realistically for surface will be in the 1800- to 2000-pound range, depending on what a volume we are putting in.

Q. Can you describe the acid gas volume calculations.

A. Sure. This is the -- if we go to the next page, I think it will give you the table.

This is the table that was in the original C-108, which it shows the calculation, or summarizes the calculations that were done to evaluate what the volume and pressure conditions are going to be when you inject this volume of acid gas into Well No. 2.

With this projected concentration, as you can see, shown on this slide of 87 and 13 or 87 and 12, what we wind up with is about 5285 barrels a day of acid gas going into the reservoir at full capacity, the 13 million.

Again I want to point out that the projected use of well is only about 10 million, a little less than 10.

But if you take this same set of formulae and apply the new proposed composition of 94 percent CO2 and 6 percent H2S, you don't get -- you get a slightly higher density of the TAG. Instead of being like this one, 779 at the surface and 828 eight at the base, I think it's more like 786 at the surface and 840, or so, at the base in terms of density, but interestingly enough because

CO_2 takes up more space than H_2S the volume increases a little bit. But not very much. The volume instead of being 5285 a day at 13 million cubic feet using the 87/12 composition becomes like 5317 barrels a day, so roughly 30 barrels a day more at 13 million with 94/6.

So really it doesn't have much of a difference. It would be certainly within the error range of the model.

And of course it is further conservative because we modeled the entire 13 million instead of the 10 that we anticipate.

But that is the effect that we anticipate, and, you know, we have done a -- in the original C-108 we did the typical volumetric modeling, that simple displacement model that we've done. We have, as a -- you know, to accommodate the desires of the Commission to have a more robust modeling effort to predict what the pressure and plume conditions are going to be, David will be presenting the more-detailed volumetric model that we did breaking out various zones within the reservoir to look at what the maximum extent could be in the most permeable zones. And then -- and he will describe that.

He will also describe the induced seismicity. That is not really part of the stuff that New Mexico Tech did, but rather what we did with the seismic data.

And then also he will describe the responses that we have and the analyses that we've done to address the concerns that the other operators had raised about possible containment in the injection zone.

And then William, Dr. Ampomah, will describe the full-blown 3D reservoir model that New Mexico Tech, that he and his team constructed in conjunction with us for this site.

So they will describe those portions, and then we'll come back and summarize what it all means.

Q. Let's talk about Notice to adjacent operators, the surface owners.

Did Geolex provide Notice of the application and the hearing?

A. We did indeed. We've provided Notice to all of the operator surface owners and stakeholders within the area of review of the well, the one-mile area of review.

We provided Notice, draft Notice for publication for the Commission, and the Commission published the hearing Notice.

We did have some, two operators originally, EOG and Matador, which expressed some concerns about potential integrity of the reservoir in the area due to some faulting. We looked at their seismic. We met with them several times. We also met with OCD and with them, and as a result of the additional work that we did and that we presented to them, which we will be presenting to the today, they withdrew their objections. So now the operators in the area all strongly support the project.

Q. Can you please identify Lucid Exhibit 4.

A. Yes. Lucid Exhibit 4 is a copy of the typical Notice Letter that was sent out and the return receipts for the mailings, as well as copies of the green cards that were returned documenting that Notice had been provided to all of the stakeholders in the area.

There's also a couple of Notices that we had to redo and track, and that we then supplied the FedEx or USPS, and those are indicated in there, as well.

Q. Did Geolex provide Notice of the hearing to all affected parties as required by the Commission's rules?

A. Yes.

Q. Thank you. Let's look at your next slide, the reservoir criteria.

A. Right. This is just the review slide.

I want to just remind the Commission that these are the primary criteria that we look at when we evaluate any potential acid gas reservoir. We want obviously, first and foremost, a geologic seal that will permanently contain the injected fluid.

We wanted to be sure that it's isolated from any fresh groundwater. In the case of this well we are about three miles below the base of any fresh groundwater, in terms of our injection zone.

We also are very concerned to make sure that it has no effect on correlative rights on existing or potential production in the area, and I think our application and our work definitely demonstrates that.

We want a reservoir that's ideally laterally extensive, permeable, has good porosity, and has excess capacity for the anticipated injection volumes, which requires us to consider other competing interests, if you will, in the reservoir in the vicinity. The salt water wells, for example. And we have evaluated those.

Then of course we need something that has a compatible fluid chemistry. We've evaluated those.

So basically Lucid's proposed AGI2 ticks all those boxes.

Q. Thank you. Your next slide No. 22 regarding the project area.

A. Right. If we go, yeah, to the this slide, it summarizes what we found when we went there.

There are 13 wells that were identified within the one-mile radius of the proposed injection well. Only a single one of these wells penetrated the proposed injection zone. It is an EOG well that was drilled to about 1700 -- 17,630 feet, and it lies approximately three quarters of a mile -- you'll see where it is in the next slide. But that well was plugged and abandoned in December of 2004. But shortly after the original completion of the well back in 1978, which was a Devonian test, unsuccessful Devonian test, they found a wet Devonian zone, which is exactly what we want but that's not what they were looking for, so they plugged the well back to like 14,600 14,590 feet, and they isolated the Devonian by over 1,000 feet in that well before it was even plugged and abandoned.

So we feel like that well, while it penetrated the injection zone and fortunately was logged and gave us some good geologic information close by, it doesn't present a problem because it has been properly plugged and the injection zone is isolated from that well.

The existing data indicates that we've got adequate porosity in the Devonian section and that it will be plenty to accommodate the proposed injection as well as the injection of adjacent salt water wells. And a review of the plugging completion reports indicate that the wells -- the injection zone is properly isolated.

If we look at the next slide real quick, I can show you in that the little box where we show the one well that penetrates the injection zone that I just described, the EOG well, where it's located to the northeast about three quarters of a mile.

Q. In identifying and electing offset wells, did you use the same area of review that you utilized for purposes of providing Notice?

A. Yes.

Q. In your opinion will the proposed AGI well impact any of the wells which you identified?

A. No.

Q. Let's look at the stratigraphy of the proposed injection well area.

A. Yeah, we looked very carefully at the stratigraphy of the injection zone in this area. The Siluro/Devonian here is characterized by a carbonate unit that is a series of interbedded carbonates with some silts and clays occasionally. It is a combination of limestone and dolomitized, or Dolomite or a dolomitized limestone, and it lies contained with low permeability limestones and shales is that we find both above and below the reservoir.

The proposed injection zone is capped by the very low permeability Woodford Shale, which in this area is about 225 feet thick.

You'll also see that the Devonian is -- I don't want to steal thunder from David's testimony, but one of things we looked at is the relative pressure differences between the overlying rock and the Devonian, and the Devonian is quite underpressured relative to the zones above it, which indicates further the quality of the seal that we have between the reservoirs and minimizes the likelihood of any excursion from the injection zone.

The next slide is just a very generalized picture to give you a picture of where the well lies where the red star is, relative to the main structural features of the Permian Basin.

As you can see, it lies in the northeast corner of the Delaware Basin as you come off into the Delaware Basin from the Central Basin platform which lies to the east of the well.

Q. Can you describe what is shown on Slide 26, please.

A. Yes. Slide 26 is the type well that is the nearest well where we got our stratographic information from to characterize the reservoir. This is just a type log. It's just to summarize where the injection zone lies relative to potentially productive zones above it, which are indicated by the red stars, and the basement and the lower (inaudible), which is as far this well was drilled into the structure.

Q. Can you describe the structural geology of the

injection area?

A. Sure. The following slide I think is probably what we could use to describe that.

This slide was included in the original C-108 and it has been further informed by the fault trace map that you see on Panel B there where we looked at seismic from -- that both EOG had in the area, and got the ability to get these seismic traces, to have a good understanding of where the faults lie and how they could potentially affect us.

But basically what you see is there is a large north/south trending fault to the east of the area of interest which is a producing Devonian field, quite a few miles, about, uh, oh, I guess roughly six, six and a half miles northeast of the proposed location. And it's a little upthrown block of where we had a little bit of Devonian production.

And as you see -- as you go down to the west and southwest you basically have fairly steeply dipping structure on top of the Woodford there, and you can see where it's affected by some of the faulting.

If we take a look at this next slide, the next cross section, it gives you a little bit of a picture of what I'm describing, that little Bell Lake Field is that thrown-up piece to the east of the little horse block that is thrown up on the east of our location, which resulted in some productive Devonian wells back in the '60s and '70s in that area.

And then as you -- as I mentioned, we basically drop off to the southeast and you can see it's steeply dipping where our well is relative to that structure.

Q. Can you describe your evaluation of the porosity of the proposed injection?

A. Yeah. The proposed injection interval shows variable porosity and permeability throughout the zone, but it generally shows good porosity in the Wristen and the Fusselman, a little bit less in the portion, upper portions of the Devonian. And the overlying Woodford, Osage and Chester, form an excellent reservoir seal, and obviously a significant difference in pressure, overpressuring in that zone vs. the Devonian which is below it.

And our proposed injection zone is about 2000 feet or 1800 feet above the basement, so we are well isolated from that.

The porosity profile both above and below the injection zone which is shown here, you can see is very, very slim, very low porosity and relatively impermeable rock, so we feel pretty comfortable about that.

Now, one thing I want to mention is we did a much more extensive look at the reservoir and modeled that, and I think David will provide that testimony here shortly.

Q. Based on your analysis did you conclude that the treated acid gas will be contained within the injection zone?

A. Yes, absolutely.

Q. Let's look at the ground water condition, so Slide 33.

A. It's the same picture, really, as ground water throughout most of the Permian. Fresh ground water is found typically the alluvium and in some cases in the red beds, the Triassic red beds that underlie the alluvium in this area, and what you find is that the bottom of usable groundwater is typically about 350 feet maximum in this area, and even that is pretty lousy groundwater but it's still considered fresh water.

These water-bearing zones we are going to isolate with four strings of casing, but the first string which is the surface casing, will extend all the way to 1300 feet, well, below the Triasic red beds.

So groundwater, surface water, et cetera are very well protected.

And just to recap, our injection zone is about three miles below, three vertical miles below the bottom of the fresh water.

Q. You looked at all the water wells within two miles of the location?

A. We did indeed. They are shown on this slide. They are tabulated in the C-108 and generally that's how we determine what the depth (inaudible).

Q. Can you summarize the geologic factors that will assure the integrity and safety of the well?

A. Sure. As I have described times before, we assure the integrity of the "system" if you will, by looking at the conditions in the reservoir and the geologic conditions in the area to provide a seal over the entire portion of the reservoir that's likely to be affected by the injection. So that's what I call geologic factors, and that's what are shown on this slide.

We also have engineering factors, which involve the design of the well itself, which we talked about earlier. But these are the geologic factors:

One is that there's no wells penetrating the injection zone closer than three quarter of a mile and that one is plugged;

the caprock has very low porosity. It's an impermeable rock which is an effective barrier to the injection zone;

and faults that enter into that appear to be fully sealed, because obviously they're maintaining a very independent pressure regime between the overlying units which are overpressured and the Devonian and underlying units which are underpressured.

All the fresh water zones are isolated, will be isolated by a conductor in the service casing. The proposed injection pressure is way below the fracture pressure of the reservoir and the caprock. And the rocks, the seismic and other geophysical analyses demonstrate that we're in a closed system.

So I think I've come to the end of my current presentation, and I'm ready to turn it over to David, who is going to describe how we evaluated the seismic potential for seismicity risk at the site, and also later on we'll talk about a condition that we are agreeing to with OCD that will help monitor that.

But David will describe that and our modeling, and then I'll come back and summarize in the end after David and William have done their show.

MS. HARDY: Thank you.

Madam Chair, I'd like to at this point have Mr. David White testify.

COMMISSION CHAIR SANDOVAL: I think we prefer to probably go ahead and cross Mr. Gutierrez and then we may just re-cross him when he comes back.

MS. HARDY: Sure.

COMMISSION CHAIR SANDOVAL: But before we do cross we want to take at 10-minute break until 11:30.

MS. HARDY: Thank you.

(Note: In recess from 11:20 a.m. to 11:31 a.m.)

COMMISSION CHAIR SANDOVAL: Ms. Hardy, are you with us?

MS. HARDY: Yes, I'm here.

COMMISSION CHAIR SANDOVAL: All right. We will back up.

Ms. Bada, do you wish to cross examine the witness?

MS. BADA: Madam Chair, I do not.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have any questions for the witness?

COMMISSIONER KHALSA: Yes, I do.

COMMISSIONER CHAIR SANDOVAL: Please proceed.

CROSS EXAMINATION

BY COMMISSIONER KHALSA:

Q. Good morning, Mr. Gutierrez.

In looking at the map of the faults that you show on Figure 11, I was wondering what the origin, what the source of data was for those faults, and if you

conducted a seismic survey on the property as part of your work on the C-108.

A. To answer your second question first, no, we did not conduct a seismic survey, and we obtained the fault traces and locations of those faults through discussions and through looking at the seismic that EOG and Matador had from the site.

Q. And are you familiar with OCD's Exhibit No. 2?

A. I am. Uhm, I think I am. Let me just take a look at what exhibit you're referring to.

Q. It would be the last page --

A. Yes.

Q. -- of that exhibit.

A. Okay.

Q. This exhibit shows a fault trace directly below Section 13 where your operation is located, and I'm not seeing that fault trace on your map, and I'm just wondering if you have been able to examine this and determine if there is indeed a fault there or if this is just an interpretation of another geologist. I just have concerns with this exhibit showing a fault right directly below your operation.

A. Well, if -- I'm just trying to make sure I'm looking at the correct, uh -- uh, at the correct figure, uhm, of OCD's exhibit.

Q. Okay. It's Exhibit 2 and it's the last page.

COMMISSIONER ENGER: Then it's Exhibit 3, the last page.

COMMISSIONER KHALSA: Well, then it's out order.

Q. (Continued) It says Affidavit of Todd Reynolds, Exhibit 2, and then it's -- there's a cross section that shows three faults. And then there's the plant you have that shows the (inaudible).

Do you see that?

A. I do. Uhm, I don't -- when you're indicating to me that there is a fault right through Section 13, I guess I'm not seeing that on this figure. It looks to me like the fault goes south of Section 13 and it's similar to the fault trace that we show with a slightly more north/south orientation, which is what we saw in that seismic that was provided to us that we looked at.

So if you look -- you have got a fault shown here that goes kind of northwest/southeast across Sections 6, 8, 15, and then 24 and then out of the Township, but it doesn't go right at Section 13.

Q. Which one --

(Note: Unidentified muttering.)

COMMISSION CHAIR SANDOVAL: It looks like it's Exhibit 3 of OCD's, the last page.

THE WITNESS: That's right. That's the what I'm looking at. And I guess I'm trying to understand where that...

COMMISSION CHAIR SANDOVAL: There's a fault trace going right through Section 13. Yeah, 3, 11, 13, 24. I'm not sure how to show this to you.

THE WITNESS: Oh, I'm sorry. Yes, you're absolutely correct. I was in the -- I was in the Township to the east. My mistake. I'm sorry. I was looking -- I understand. I see the fault that you're looking at now.

A. And we have that fault shown on our map going right through Section 13. You can see it on our figure that is up on the screen right now. You see that fault. It goes right through the actual No. 13 on our -- on our -- on our panel B right there. That is the same fault trace, I believe, that we're seeing here.

There's little bit of a different interpretation about those two faults and whether they actually come together. Our own look at the seismic doesn't have those two faults coming together like it is shown on this map, even from the east of there.

But that fault that comes right through Section 13 is indeed shown on our map, and it goes through 24, 13, and 11, and then peters out around Section 11.

They've got it going further north. We didn't see that extension in the seismic that we looked at.

Q. And when you look -- the seismic that you looked at from the oil company, did it adequately cover this section where your operation is located?

A. Absolutely.

Q. And where you have faults that we see in red, are those part of the fault slip analysis that you have done on the fault slip potential model?

A. Yes. And David will be discussing that very specifically.

Q. Because from what I remember reading in Section 4.5 of your C-108, it seems that only the faults in Figure 11 have the fault model run on that. So I just wanted to make sure that the model covered these faults that we see right there in that section.

A. Absolutely. What you have to understand is that we didn't do the fault slip analysis modeling until long after the application. The second go-around of that slip analysis modeling was done with this seismic. We did it with only the information that we had available at the time that the application was prepared, and we had not seen this seismic yet at that time. We saw that as a result of EOG and Matador's original objections.

So basically the fault-slip modeling that was done for the C-108 was based on the information that we had at the time, but what David will be describing shortly, is the fault slip modeling that was done using all of the faults that we obtained from looking at the seismic that you see on panel B.

COMMISSIONER KHALSA: Right. Right.

COMMISSIONER ENGLER: Are you done?

Hello, Mr. Gutierrez. Tom ENGLER. How are you?

THE WITNESS I'm well, Dr. ENGLER. How are you?

COMMISSIONER ENGLER: Good to see you again. Thank you for all the hard work.

CROSS EXAMINATION

BY COMMISSIONER ENGLER:

Q. Just to follow up on the slides shown, which is this -- this faults. Well, the -- this is -- well, page 28 where the slide is shown, the fault that you have shown, the traces, that's in the Devonian Formation, correct?

A. They are. They are in the Devonian and, like I said, David will go into great detail on this part of the application. But they are through the Devonian, and they tend to peter out in the Woodford and the Mississippian above that.

Q. Yeah. That would have been my follow up is, you know, how far they go, and you're saying they basically

terminate in the Woodford, right?

A. In the Woodford and/or the Mississippian immediately above the Woodford, yes, sir.

Q. In your examination of a fault with the seismic data, could you determine how much vertical throw or displacement on the faultS?

A. Uhm, it's variable, but generally what we're seeing within the reservoir is, you know, a couple of hundred max, and in most cases more like 100 feet.

Q. And so -- because you have so many fault traces so I would expect you have a variable throw anywhere from -- you said a minimum of 100 feet to maybe a couple of hundred feet depending on the fault?

A. That's right. And the other thing, Dr. ENGLER, that is particularly even more important than that in terms of what we see in the results of the fault slip modeling is the attitude of those faults. So one of the things that David is going to be discussing, which is really a very significant factor in how those faults behave when subjected to increases in pressure in the reservoir is what their orientation and their anGeolexe is.

So we have taken these faults actually and broken them up into many individual traces.

And I feel like I'm taking away David's

thunder here, but the fact is that we also then evaluated the faults relative to three different scenarios of potential anGeolexe of the faults where we had, you know, 80 degrees plus or minus 10 degrees, 70 degrees plus or minus 10 degrees, 60 degrees plus or minus 10 degrees, and you'll see some pretty significant differences in how they react.

Q. Thank you. One other different question, different topic: What precautions is Lucid Energy doing when it drills through the Delaware Mountain Group for the AGI2 well?

A. Well, we are going to mud up. I mean, we've the done this numerous times before where we drill through a zone where we're already injecting acid gas, and we will -- you know, we will be prepared for it, we know where it is, and we will mud up appropriately across that zone.

We also will be analyzing, doing -- you know, we'll have an H2S monitor on the -- on the -- on the mud logging equipment, and we will be continuously monitoring that.

We did almost exactly this same thing when we drilled the Zia No. 2 well at DCP where the Zia No. 1 was injecting nearby into the DMG.

COMMISSIONER ENGLER: Thank you. No further questions.

COMMISSION CHAIR SANDOVAL: Thank you. I think Dr. ENGLER and Ms. Khalsa answered most of mine, so I have no questions.

Ms. Hardy, do you have any redirect?

MS. HARDY: I do not. Thank you.

COMMISSION CHAIR SANDOVAL: All right. Would you like to call your next witness?

MS. HARDY: Yes. Madam Chair, Lucid calls Mr. David White.

COMMISSION CHAIR SANDOVAL: No problem.

(Note: Pause.)

MS. HARDY: We're ready.

DAVID WHITE,

having been duly sworn, testified as follows:

COMMISSION CHAIR SANDOVAL: All right. Please proceed, Ms. Hardy.

DIRECT EXAMINATION

BY MS. HARDY:

Q. Please state your full name for the record.

A. David Allen White.

Q. Where do you reside?

A. Albuquerque, New Mexico.

Q. By whom are you employed?

A. Geolex, Incorporated.

Q. What is your position with Geolex?
A. I am a senior geologist and project manager.
Q. Are you familiar with the matters addressed in Lucid's application?
A. I am.
Q. Have you previously testified at a Commission hearing?
A. Yes.
Q. Were your qualifications as an expert in geology accepted?
A. Yes.
MS. HARDY: Madam Chair, I tender Mr. White as an expert in petroleum geology.
COMMISSION CHAIR SANDOVAL: Any objection, Ms. Bada?
MS. BADA: OCD has no objections.
COMMISSION CHAIR SANDOVAL: Any objections from the commissioners?
COMMISSIONER ENGLER: No objection.
COMMISSIONER KHALSA: No objection.
COMMISSION CHAIR SANDOVAL: Okay. Mr. White is certified as an expert in that field.
Please proceed.
MS. HARDY: Thank you.
Q. Mr. White, let's look at your Slide No. 36. Did

you evaluate the potential for induced seismicity at the site?

A. Yes, we did. And in order to evaluate the potential for induced seismicity at the location of the proposed Red Hills AGI2, Geolex and myself did complete an induced seismicity risk assessment to evaluate the risk associated with injection operations not only of the proposed AGI well but also considering the injection contributions that nearby SWD wells gave.

To complete this evaluation, we utilized the Stanford Center of Induced Seismicity Fault Slip Potential Model, which consists of a hydrologic simulation capable of simulating multi-well injections in areas. We did this for a period of at least 30 years and then subsequently, utilizing this model, were able to yield estimates of the potential risk for injection-induced slip according to the designed injection scenario we inputted in the hydrologics in the mission.

Q. Looking at Slide 37, can you describe the model subsurface features, please.

A. Yes. In order to complete a model, a slip probability model of this, as we've just seen discussed in Alberto's testimony, we need to have an idea of what subsurface features are present in the location of the proposed well.

In the ap. shown to the right here, I have included the traces of 11 fault features that we've identified in the area, generally trending northwest to southeast and present within the targeted Devonian injection reservoir.

As Alberto alluded to, or Mr. Gutierrez alluded to in his testimony, due to some uncertainty in identifying the absolute dip of fault features in this area, we did simulate multiple-case simulations in order to address that uncertainty, specifically allowing the model simulations to be conducted over a range of fault dip angles from as low as 60 degrees to a vertical at 90 degrees.

When we look at the trace map shown here we see the nearest fault to the proposed AGI well location approximately a quarter mile away.

Q. And what is shown on Slide 28?

A. In this panel, or in this figure I'm showing the 11 faults identified as they have been defined in the FSP simulation, and what this map shows, that in order to characterize nonlinear expressions of faults included in the model, those 11 main faults were subdivided into 32 fault segments in the model simulations, and so when we get to slides, forthcoming slides and if we give reference to fault segment of some numbered fault segment, that would be in reference to the way the major faults are subdivided according to this map.

Q. And what conditions are required to induce fault slip?

A. So before we get directly into that discussion, another -- in addition to having an understanding of what subsurface features are present you also need to define for the fault slip potential model some characteristics of the local stress field, characteristics of the injection reservoir itself, as well some material properties of the fluids being injected.

So this table shown to the right here is just a summary list of the input parameters that were utilized in the slip probability simulations that are being presented today.

Q. What is shown on the next slide?

A. So now, as I stated a couple -- a minute ago, this table summarizes the 32 fault segments that make up the 11 faults identified in the area as they are going into the simulation.

We see in the segmented table there, we see the 32 fault segments plotted, and in the columns to the right we see the determinations that the fault-slip-potential model first makes.

So the first thing, based on stress

parameters and the orientation and attitudes of subsurface features you input into the model, the first determination that you are going to make is: What is the required increase in core pressure that each of these features is going to need to experience in order to likely induce slip?

So in the second third and fourth columns of each of these you see the core pressure required to induce slip. And those are separated based on the three cases in which we buried fault depth in the simulations. So you see the second column dip is equal to 80 degrees plus or minus 10; dip equal to 75 degrees plus or minus 10 in Case No. 2; then dip equal to 70 degrees plus or minuets 10 in the third case.

And before we move on from this slide, when we look at the initial estimations of model simulation where they are identifying what pressure conditions or what increase in pressure conditions are necessary, of these 32 fault segments, I have highlighted with red arrows here three particular segments, in 6, 7 and 21 that we would probably -- that we want to keep an eye on, as they exhibit the lowest pressure increase required to induce slip.

Q. And did you look at injection wells in the vicinity of the proposed AGI?

A. We did. As I stated in the introductory slides, this evaluation was designed not only to consider the influences of the proposed AGI well but also to consider contributions made by SWD, nearby operating and permitted SWD.

And as you can see on map shown to the right here, we have 16 injection wells, including the proposed AGI well, that were included in the model simulations, and these permitted and active SWD wells all lie within 10 miles of the proposed AGI location.

In taking a little bit closer look at the distribution of wells in the area, we do pick out pretty immediately the proposed AGI well and the nearby Striker 6 SWD2 wells located less than a mile and a half to the east/southeast, pretty much isolated from the majority of the traditional SWD, at least to some degree.

Q. Can you describe the model injection scenario.

A. So in the table shown to the right, I like to start with tables and figure it in, but in the table shown to the right I've got the 16 injection wells that were included in hydrologic simulations, along with their identifying API number. And in the final three columns to the right we have the simulated or the injection volumes at which they were simulated at, these scenarios presented today, as well as the duration of their simulations.

So typically for the AGI well we want to at least simulate a period of 30 years to support that operation of the AGI well, however in this area we've got SWD wells operating prior to the start year for the proposed AGI, the total simulation duration was increased to 34 years.

And as you can see in the table of simulated injection volumes with those nice round numbers, all of the injection wells included in the simulation were operated at their maximum anticipated daily injection rate as it was recorded in their respective C-108 applications.

So these daily injection volumes in the simulation would reach 20-to-50,000 barrels per day, which, if you want to do the quick math, it should be important to note that what the barrel equivalent of what the proposed AGI is requesting would represent around 1.2 percent of the total volume being injected or proposed to be injected.

Q. AND What were the injection simulation results?

A. So in this slide we're taking a look specifically the result of the hydrologic simulations. So the model will run the injection simulation of these 16 wells and give you results as to what the pressure, what the associated pressure effects in response to that simulation are. That's the proposed scenario.

So if we look at the top left panel we see a Result in Pressure map. That's at year 2050, so the AGI has been in operation for 30 years, some additional SWD wells have been operating for 34 years. And you see the colored scale to the right shows the increase in pressure associated with the colors on the map, so with warmer colors illustrating a higher change in pressure and cooler colors indicating a lower change in pressure.

So we see that once again the proposed AGI and the Striker 6 well are kind of isolated from the other SWD wells in the area, but they are still going to be feeling at least some influence in terms of pressure.

When we take a look at the top-right panel, which is essentially the same map just I zoomed in, added survey lines, and added the fault trace maps for -- or the fault traces for faults interpreted in this area.

And you have to excuse me but I think our camera feed is overlying this figure, but when we look at the closer view in this area we see that typically around the AGI well we see increases in pressure at the end of this simulation somewhere in the order of 340 -- 330 to 350 psi, using the scale from the top-left panel.

When we look at the lower two panels, I've included the pressure-through-time plots that each fault segment included in the simulation experiences throughout the simulation -- or the injection simulation; and then in the lower-right panel we see the single well radial pressure solutions for each well included in the model.

So probably most specifically, or most importantly, we see that once we get about a distance of about six miles away from each of these wells, their result in pressure effects have dropped down to below 50 psi or so.

Q. What's shown on Slide 44?

A. On this slide we're showing the additional results that the FSP model supplies. You know, initially I had stated that the hydrologic simulation to characterize the result in pressure conditions is shown, but now the model will take the next step and actually combining the results of the hydrologic simulation with input parameters characterizing stress fields in the area, as well as the porosity and permeability potential in the injection reservoir, and it's going to determine or make an estimation of what is the probability of slip associated with this injection scenario for each fault segment included.

So for -- as I mentioned previously, we ran three iterations varying the did, the absolute dip angles of faults in the model, and those are shown, from left to right, Case 1, Case 2, and Case 3, and for each case I've plotted the fault slip potential value or essentially probability of slip against time; and in the lower panel I show a fault trace slip, which fault traces are color coded based on their slip potential.

So we can see in Case 1 where we have the vertical or near-vertical fault, we see the FSP simulation estimates Fault Segment 21 and Fault Segment 6 having .05 and .06 probability of slip. When we look at the results for Case No. 2 where faults are allowed to become a bit more shallow, we see once again Fault Segment 6 and Fault Segment 21 being responsive to the injection simulation, with slightly increased probabilities of slip. But we also see the addition of Fault Segment 7 with a .06 probability of slip.

And then as we move to Case No. 3 where fault dips are allowed to vary across their shallowest and most shallow ranges, once again we still see those three fault segments, Fault 6, 7 and 21 with additional increased probability of slip.

So we see a real clear pattern that as these faults become more shallow we see increasing probability of slip associated with the injection scenario.

But it's important to note that one of the reasons we've designed our fault slip simulation the way we have, operating all of the wells included at their maximum daily injection rates, is to provide a conservative estimate of risk so that we are well aware of what potential risk may be involved, and we have all of those wells operating at their maximum volume from start to finish.

Additionally because of limitations of the FSP simulation model itself being only able to evaluate one fluid type, we also model the AGI well as if it were disposing of produced water, which is going to essentially be noncompressible, whereas injected acid gas has some compressibility of drastically lower viscosity.

Q. What's shown regarding the simulations on your next slide?

A. So this is just taking a little bit different look at both the hydrologic simulation results as well as the fault slip probability estimates made by the model. Uhm, and you'll see, despite including 32 fault segments in the simulations I have truncated the tabulated list shown here to only include those faults that exhibit some non-zero estimate of risk. So all remaining faults that were removed from this table throughout the simulation period did not exhibit an increase, or a non-zero probability estimate of slip.

In these columns we see first -- the first three columns are the results of the hydrologic simulation model where we have the fault segment summarized -- or the fault segments and their predicted, their model predicted core pressure increase in response to the 16-well injection scenario.

Then in the next column we see the predicted core pressure increase when the AGI is excluded from simulation.

So just taking a look at the first three columns, which are applicable to all case simulations, we see that in terms of pressure estimated by the model, removing the AGI only accounts for somewhere around 15 to 25, 15 to 30 psi in the hydrologic simulation results.

In the next groups of three columns we show the results from the three cases in which fault dip angles were allowed to vary, and we see -- in the first column of each of those groups we see a model determine core pressure required to induce slip, and then the probability of slip at the end of that 34-year injection simulation.

Then we reran the simulations without the AGI to see what contribution the AGI has.

So you can see when we remove the AGI from the equations we have no changes in the probability of slip or only slight reductions on the probability of slip.

So generally we see faults in this

assessment exhibiting increasing potential for slip as they grow increasingly more shallow. Across all simulations we see fault slip probability estimates ranging from .05 to .29 with the majority of faults simulating a zero probability of slip. And you see pretty clearly that the simulation results demonstrate that specifically the Red Hills AGI2 only contributes minimally to the total risk or total potential for fault slip.

Q. The next slide, can you summarize your potential for fault slip?

A. Yeah. As I just kind of reiterated a little bit, based on these results, operation with the proposed Red Hills AGI2 is not affected by the FSP model to contribute significantly to risk of potential slip.

One thing that -- you know, I discussed a little bit about the conservative approaches we've taken to simulate these models. Another thing to consider is that some of the fault features included in this simulation, you know, they're interpretations, and specifically we have displayed these traces as they were shown to us and interpreted by the operators we've indicated, whereas our geophysicist who was also involved in those conversations, from the limited viewing of those data had some differing interpretations on his model, but due to the time available for us to review those data we chose to stick with what the operators' interpretations of those data were.

So when we conducted our multiple simulations or multiple simulations were conducted, we were to address what uncertainty we had regarding the fault dip or the absolute fault dip of these features. And in order to address that uncertainty we allowed the additional case simulations to be conducted where the dip angles were allowed to vary across a range of 60 to 90 degrees.

Across those cases, or generally in all cases, from the results of those cases we see that high-angle fault conditions, we see fault-slip probability values ranging from about .03 to .06; however, when faults are simulated under the most shallow conditions, we see estimates of slip probability ranging from .10 to .29.

Once again, as we simulated these injection wells at their maximum anticipated rates, it's important to remember that this may or may not be the case with these wells actually being operated. For example, the Striker 6 SWD2 well is simulated at volume -- at a daily injection volume of 32,500 barrels per day, whereas when you actually look at their reported injection volumes since the time they began injection operations, they have averaged more along the lines of 75 barrels per day.

Additionally, the Red Hills AGI2 well, as we discussed in previous testimony, was modeled to receive its total 13 million standard cubic feet per day; however, that total volume is actually anticipated to be split to some degree with the existing AGI well.

So just to summarize matters, the operation of the proposed Red Hills AGI2, is not anticipated that to the total potential for injection induced fault slip.

Q. And will Dr. Ampomah also address seismic issues?

A. Yes.

Q. Can you explain what you did to evaluate the impact of Red Hill AGI2.

A. Yes. As Alberto has -- or as Mr. Gutierrez has testified to, since submission of the original C-108, Geolex has completed additional, or taken an additional look at the properties of the reservoir and completed an additional multiphase evaluation to further assess what the impact of Red Hills AGI2 will have on the Devonian reservoir.

This multiphase evaluation included a more in-depth look at the targeted Devonian injection reservoir, taking a more detailed review of available subsurface data in the form of well logs, injection units and drill-stem tests to see if we can really delineate further porosity or permeability distributions available in the Devonian reservoir. From that more in-depth look at the reservoir we were able to utilize volumetric determination methods to produce a more detailed, slightly more -- slightly sophisticated estimate of what the result of acid gas may look like, specifically considering what the plume may look like under a radial dispersion pattern, as well as if we apply local structural constraints or constraints based on density contrast in the acid gas in the formation fluids.

So we've been able to produce a slightly enhanced volumetric estimate.

And then as shown here in the last bullet, one of things we'll cover in this section is our approach to addressing concerns that were previously expressed by Matador and EOG, specifically regarding the containment potential of the Devonian reservoir in this area.

As previously discussed briefly by Mr. Gutierrez, discussions were had between Lucid, Lucid's technical aide and these operators, as well as participation by NMOCD staff, and these operators have since withdrawn their objection to the project.

Q. Can you explain what's shown on your next slide, No. 48.

A. So in this slide we provide a summary of our additional look into the potential of the Devonian reservoir in this area.

From our review the proposed injection interval was subdivided into 10 discrete zones based on porosity and permeability characteristics. These zones were shown in the offset well log representing the EOG Resources, government and public, all shown to the right, where yellow highlighted areas correspond to intervals of porosity greater than 12 percent.

We see of those 10 zones eight of those were identified as usable intervals of porous strata. These types included: Solution-enhanced primary porosity, solution-enhanced fracture porosity, and intervals of even small-fracture porosity, which we have seem to be important, not in main courses, but contribute or are able to receive good amounts of fluid in additional wells.

From available well log data we were able to estimate average porosity values for these eight identified zones, and from utilizing the Archie equation we were able to estimate total volumes available.

Q. Would you describe the injection reservoir characteristics.

A. Yes. On the table shown on the right here we kind of have a summary of the 10 zones identified in our additional review of the injection reservoir and any of the associated subzones where characteristics in the reservoir were able to be part of...

But in general we see in the end zones porosity, interval porosities ranging between 1 to 14 percent. We see an average across the total injection zone, an average across all zones, the average porosity at 3.5 percent.

When available, if we had adequate drill-stem test or injection test data or resistivity log data, average permeability values were estimated, and then to assure that permeability values were reasonable or further refined permeability estimates, we consulted the extensive dolomite, all the same studies that we see at...

Q.   How did you characterize the AGI plume?

A.   So, as I mentioned in the first slide to this section, we first conducted a further look at the reservoir characteristics of this area, and armed with that knowledge we were then able to take our more discretized look at the injection reservoir and estimate what the result of the AGI plume may look like utilizing our porosity and permeability based upon the volumetric determination.

And this was made with the proposed AGI2 well operating at the maximum injection rate of 13 million standard cubic feet per day, once again attempting to provide a survey of what the maximum extent of this thing, the AGI plume, might reach for a duration of 30 years, and at the time the calculations were made based on acid gas mixture of 87 percent CO_2 and 12 percent H_2S.

Q. And can tell us what's shown on Slide 51?

A. So this is just kind of some bulleted details about how the volumetric determination was completed.

The volumetric determination gives us at least some way to estimate the acid gas after 30 years of injection. Armed with more detailed discretized breakdown of the targeted injection reservoir, I can get us a good idea of both what its extent might be from an aerial perspective, as well as what its distribution might look like within the reservoir.

In attempting this determination, first the target total injectate volume of 13 million standard cubic feet, that is fractionated based on available porosity observed within each identified zone or subzone, and then those fractions subsequently scaled according to the average permeability values.

Once we have fractions identified and which -- that are based on available porosity and permeability potential, we are then able to calculate the result in acid gas both under radial dispersing conditions, which may be similar to if cases in which faults in the area are transmissive to fluids, as well as calculate the rate of the passive gas footprint based on some preferential updip dispersion behavior.

Q. Can you describe your findings regarding transmissive faults.

A. Yes. So in this slide we show what the volumetric determination is. Essentially under our radial dispersion regime or, you know, uhm -- and under these conditions we see that the acid gas plume would have, or is calculated to have a maximum extent from the AGI wellbore of about .48 miles. In this case with faults nearby, that plume would extend across planes of those interpretative faults.

And in the panel to the right here we see kind of a cross-sectional view of the volumetric determination, where we see what volumes of acid gas are being sequestered in which zones. So immediately taking a look at that we see Zone 1, Zone 3 and Zone 8 taking significant volumes of acid gas, and we see that the Zone 8 typically -- or extends the furthest from the AGI well.

So what we're seeing in the map view of the total plume extent would essentially be the outer edge of radial dispersion within Zone 8-C.

Q. Can you please describe your findings with

regard to subsurface constraints.

A. Yes. In this slide we kind of build upon what we've gone through with the radial dispersion model, and we think, you know, for the look at the location of the proposed AGI well with respect to local structure in the area, as well as considering density contrasts of acid gas in comparison to the anticipated Formation fluids. We might say: Okay, maybe a radial dispersion model might not be the best approximation of what this will look like.

So, as we see here, taking a look at local structure, we see the radials located downdip of the structural high to the northeast, and we see generally depth to the top of the Siluro-Devonian injection reservoir, which is on this map, becoming deeper towards the southwest.

Based on our equilibrium calculations of the anticipated acid gas characteristics, we expect that the acid gas will have a specific gravity of .85, which might further -- that density contrast may also affect dispersion patterns of the acid gas in the reservoir.

So based on local structure and those density characteristics, we would expect that acid gas would preferentially migrate northeast towards the structural high.

And so to kind of get a picture of what

this looked like we conducted or completed calculations to determine varying fractions of acid gas that was allowed to migrate preferentially if or when the remaining fractions calculated on what they would look like under radial dispersion. And those parameters would specifically include the 90 percent, 70 percent and 50 percent of acid gas preferentially migrates updip.

Q. Can you describe your findings regarding sealed faults.

A. So this is the results when acid gas is allowed to preferentially migrate updip. It's noted as sealed faults, as it's, you know, potentially these faults lying to the west of the AGI location may -- if they're sealed they may be a barrier to dispersion in that direction.

But as shown in the map we see essentially the polygons illustrating the three different scenarios for acid gas transmission updip where the yellow represents 90 percent of acid gas migrating updip, blue representing 70 percent migrating updip, and then the red showing 50 percent migrating updip, and their result in acid gas footprint.

In the figure shown to the right we see the corresponding distribution within the reservoir under these conditions; however, for this figure only the maximum lateral extent is shown reflecting the conditions when 90 percent of acid gas migrates updip.

Once again we see Zone 8, 3 and Zone 1 are taking the greatest volumes of acid gas.

Q. What are your conclusions regarding the AGI?

A. So upon completion of our additional review of the Devonian injection reservoir in this location, we identified 10 discrete zones within the reservoir characterized by or delineated by their observed porosity and permeability characteristics. Eight of these zones were identified to contain some levels of or some degree of usable porous strata. Using volumetric determination methods under a radially dispersing regime, we see an estimation that the acid gas plume after 30 years may extend up to 0.48 miles from the AGI wellbore, and when we apply some additional constraints based on some local structure, density characteristics between the acid gas and formation fluids, we see estimations of the resulting plume ranging from .67 to .9 miles updip direction.

So we provided in this evaluation a more detailed digitalized look at the injection reservoir and the distribution of porosity within it. One of the things these results does not consider is the potential for a cross flow within and between identified zones. Not out of the injection zone itself but between or identified zones. If those are found to be present in the subsurface or are present, those cross flows between zones may result in a reduction of the plume footprint.

Q. Did you evaluate potential for vertical migration?

A. We did. As it's been discussed previously, a couple of points in this area:

The nearby operators had, on submission of the C-108 or later on down the road, initially expressed some concern that faults in the area, may present pathways for acid gas to migrate upward and outward, and so producing or causing waste and risk to operators in the area.

When we evaluated, Geolex evaluated -- to address these concerns Geolex took kind of a broad approach to addressing these, looking at -- well, based on wide studies characterizing pressure conditions in the Delaware Basin, we compiled available drilling fluid records to get a more local picture of pressure conditions in zones overlying the Devonian in this area.

We also had a preliminary drilling fluids program prepared for the Red HillS AGI units to identify the specific recommendations for fluids to -- in order to accommodate overlying direct pressure conditions in this area. We will present these today. I think they were presented to Matador and EOG, who have since withdrawn their objections.

Q. And what did you determine regarding overpressured conditions in the Delaware Basin?

A. So, as I stated, we start off with kind of a high-level look. What I'm showing today, or what I'm showing in this slide is an excerpt from Luo et al, 1994.

What I have plotted is their observation of pressure conditions in strata overlying the Devonian in the War-Wink field area.

So we see that they have reported from Wolfcamp, uh, Wolfcampian down to Woodford an interval and overpressured angle that's characterized mainly by deep water shales of some sense, essentially, and they note observation of this pressured and overpressured system covering six counties in Texas and New Mexico, from Lower Bone Springs to Woodford Formation strata.

It's important to note that underlying this overpressured interval in the carbonates of the Devonian, which are the proposed target injection reservoir for the AGI2 well you see a return to lower pressure emissions, at least from this study of the Delaware Basin.

Q. What's on your next slide?

A. On this slide we take another look at regional assessment of overpressured conditions that have been identified in overlying strata.

You'll have to excuse me. It looks like there's a couple of slides overlapped, but we'll work through it.

So what's shown in this slide is an excerpt from Rittenhouse, et al., which is showing the mapped extent of present-day overpressure in the Eastern Delaware Basin.

This is an expression of a regional pore-pressure model that has it all developed, utilizing more than 23,700 mud weights and data from greater than 4,000 drill standard -- drill-stem tests and fracture injection tests.

And what we would, uh -- uh, we would advance to the next slide showing an example well log. We would show an example well log that shows the observations of Rittenhouse et al. that an overpressure system exists beginning once again -- from the Lower Bone Springs and remaining elevated, pore-pressure gradients remaining elevated to the base of the Woodford Shale. In their findings they also see mud records matching that pore-pressure gradient where higher density muds are required, and the return to normal pressure system, normal pressure conditions by weights utilized of 8.8 pounds or so below the Woodford Shale.

So from a high-level perspective, you know, from a regional look at overpressure conditions, it looks like their radials, those overpressured conditions may be present in the location of the Red Hills in AGI2 well. So the next step we took was to compile available mud records in the area to see if those same heavy mud weights had been utilized in zones, producing zones overlying the Devonian in this area.

And in the map shown to the right I have those mud records plotted. We see utilized what wells we were able to yield these mud records. We see mud densities being utilized ranging from 9.9 to 15 pounds per gallon, and across all wells we see an average fluid density utilized at 12.4 pounds per gallon.

Just to be clear, this is in the overlying zones, uh, overlying producing zones above the targeted injection reservoir for the Red Hills well.

Where available, and specifically in this area there were not many, but where available where mud records were reported for wells that penetrated the Devonian, we did see a return to lighter mud weights at about 8.8 pounds per gallon in the Devonian.

Q. Can you describe the Red Hills AGI2 fluid program.

A. Yes. So this -- shown in this slide is an excerpt from the drilling program I mentioned we had generated for the AGI well. We see, based on the recommendations of Agave, Incorporated, overlying the Devonian injection interval they recommend utilization of mud weights between 12.4 and 12.5 pounds per gallon, and then upon penetrating the Siluro-Devonian interval they recommend mud weights of 9.0 to 9.2 pounds, noting potential hazards of "severe lost circulation".

So based on the high-level look at regional pressure conditions, the mud weights utilized in the immediate area and these recommendations, it's looking like the Devonian is going to be underpressured relative to the overlying viscosity in this area.

Q. And what are your conclusions regarding the potential for vertical migration?

A. So based on the observation of these drilling records, both from a regional perspective to records that are specific to the immediate area of the AGI well, operation of the proposed AGI is not anticipated to present risk for vertical migration or being injected out of the targeted reservoir.

With overlying -- with an overpressured system above the injection reservoir it's likely more that if there were open conduits for fluid migration and based on the observed pressure differential, it's more likely that the Devonian would be receiving fluids or input from those overlying zones rather than that differential being overcome to migrate acid gas out of the reservoir.

Q. And, Mr. White, in your opinion will the proposed well result in waste or damage of correlative rights?

A. No.

Q. In your opinion will the well adequately protect oil and gas zones?

A. Yes.

Q. In your opinion is the proposed injection zone a good candidate for the injection of acid gas?

A. Yes.

Q. And in your opinion will the injection of acid gas into the proposed well protect human health and the environment?

A. Yes.

MS. HARDY: Thank you. I have no further questions for Mr. White.

COMMISSION CHAIR SANDOVAL: Thank you. I think before we go into cross we are going to take a half-an-hour lunch break. So we will come back at 1:15.

Thank you.

MS. HARDY: Thank you.

COMMISSION CHAIR SANDOVAL: Thanks everybody.

(Note: In recess at 12:48 p.m.)

COMMISSION CHAIR SANDOVAL: Okay. We will continue with cross.

Ms. Bada, do you have questions for the witness?

MS. BADA: OCD does not.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have questions?

COMMISSIONER KHALSA: Yes. I have questions.

CROSS EXAMINATION

BY COMMISSIONER KHALSA:

Q. Good afternoon, Mr. White. I just have a couple of questions about the fault potential model that you conducted.

One of the things that -- or one of the parameters that I saw in the C-108, uh -- so that's the, uh...

The exhibits are not very well organized and it's hard to find stuff, so sorry.

I'm looking at Table C in the C-108, and one of the material properties that was used was the density and viscosity of water. That was -- I presume that those values were used for the injection well in the other estimates provided. I just wondered if you have run the program with the simulation using different densities of water.

A. No. So -- and you're looking -- just for clarification, are you looking in the C-108 application itself?

Q. That's correct.

A. So the simulation that's presented there, I think as Mr. Gutierrez had explained previously, was based on our current knowledge of faults at the time, so it included less features.

If we look at the simulation that's presented in the presentation today, that would be reflective of what the most recent fault slip potential simulation is. And that, as well, contains a similar table of input parameters.

COMMISSIONER ENGLER: I think -- this is Tom Engler. I think, Ms. Hardy, it's Slide 39.

MS. HARDY: Thank you.

COMMISSIONER ENGLER: If I'm right. Is that right? Am I on the right page?

COMMISSION CHAIR SANDOVAL: And maybe just for future reference, if we have page numbers on the slides.

MS. HARDY: Yes.

THE WITNESS: Yes, ma'am.

Q. So you used fresh water for all simulations?

A. Well, it's not fresh water. It's a greater density than fresh water. It's allowed to vary between

1020 kilograms per cubic meter to 1060 kilograms per cubic meter in the simulation, and because of the limitations of the fault-slip potential model it was only able to evaluate one fluid, or run one set of fluid characteristics, so the SWD were operated under these conditions of injecting characteristics, as well as the acid gas injection well was simulated like it was an SWD well.

And this provides us a greater conservative estimate of risk, as acid gas as shown at the base of the table here, has differing viscosities, different densities, and is a compressible fluid, whereas modeling the AGI with the characteristics of the injectate similar to an SWD well, we are dealing with a noncompressible fluid, so the influence it has in terms of pressure will be greater, thus producing a more conservative estimate of risk.

Q. And am I correct in interpreting most of these faults are (inaudible) faults?

A. Yes.

Q. So then my next question is: Parameters, the variables that you used before, the dip of the normal faults, but is the (inaudible).

A. Yeah. So with the -- the three case simulations were run at 80 degrees, 75 degrees and 70 degrees;

however, the uncertainty associated with each of those cases was set to 10 degrees. So essentially in the Monte Carlo simulations the determination of the associated risk for each of those cases, they were, the faults were allowed to vary between that range to estimate the total risk.

Q. And do you think that's conservative when most normal faults are somewhere between 40 and 73 dip?

A. Well, I think that --

Q. Shallower dip angles?

A. Well, I think that's why we conducted those case simulations, to allow the range of typical normal faults which we might see at 60 degrees, combined with commonly near-vertical faults that we often see in the Permian Basin.

Q. I have one more question.

This might not be something that is exactly relevant to your testimony, but I wondered if there was any data as to the material that seals some of these faults. Is it a permanent seal? Did you do any research on that? I'm interested to know how acid gas might interact with a permanent seal on a fault and how that might change the fault-slip potential model?

A. Well, I don't have any information regarding whether faults in this area are sealed or not, however that is not a consideration that the model would be capable of addressing, whether or not those are sealed or not. I assume -- or the model assumes that if there is a subsurface feature, a fault feature in the area based on the defined input parameters of orientation, dip and the stress state -- or the local stress state in that area of the well location, it assumes that it can, or it is potential to experience -- it has potential to experience slip.

So I don't think it considers in any way whether or not that's sealed or not.

COMMISSIONER KHALSA: All right. Thank you. No further questions.

COMMISSIONER ENGLER: My turn?

COMMISSION CHAIR SANDOVAL: Go ahead.

CROSS EXAMINATION

BY COMMISSIONER ENGLER:

Q. Hello, Mr. White. Good to see you again.

A. Likewise.

Q. I got some questions. I guess I'll reference these by slide number. Slide No. 48, if you could advance to that slide.

A. Yes.

Q. I'm curious. You have a variety of porosity types. How did you determine the porosity types?

A. Uhm, those porosity types were identified based on the log response viewed in the area's well logs that were, uh, reviewed.

Q. You're getting those from the log data, correct?

A. I'm sorry?

Q. So you're identifying different types of porosities from the log data?

A. Those were interpreted from a log data and additional subsurface data whether it be the mud log record or drilling records, or whatever was available to us.

Q. Okay. On your Slide 49, the next page, what is the BWE on your table?

A. That is the barrels of water equivalent that was determined to be available within each zone for sequestration.

Q. So that's the volume in a particular zone as a function of barrels. Correct?

A. Yes.

Q. So that came from your porosity, your thickness, your 1-SW, water saturation, and area?

A. Uh, yes, within a one-mile area of the proposed well.

Q. So the area -- I'm sorry. So the area was assumed to be one mile for each one of those?

A. (Note: Pause.) If I recall correctly, yes.

Q. So what's the purpose of having that volume if you're assuming the one-mile area?

A. Oh, I apologize. I believe I have misspoken. The Barrels of Water Equivalent is the calculated volume available for that zone. Uhm, yes. So it's the available volume within a one-mile area.

Q. Okay. That's for a whole one mile. So you assumed a one-mile area for each one of those.

A. Yes.

Q. Why did you assume the one mile?

A. Because I think that was within the bounds of -- (Note: Pause.) Uhm, at this time I'm uncertain. I would need to -- I would look at the full spreadsheet for this. This is kind of a summarized version of what was, uh, summarizing the evaluation.

Q. Let me ask this, then: Did you use those -- you did -- did you or did you not use those values in your figure? On your Slide 52 where you're partitioning by zone, did you use any of those particular volume calculations?

A. So we utilized the volumes, uhm -- I think there is -- what's that? (Note: Pause.)

So I think there may be a bit of a disconnect. The volumes, if I recall correctly here, are -- in the Barrels of Water Equivalent column, I believe are reflecting, based on the fraction of formation fluids not able to be displaced, uh, once the total remaining volume; whereas, when we cal- -- in the determinations in the following slides, that was based on the specific fractions of acid gas going to each zone.

So --

Q. Yes, I understand that. I was trying to get to what you're using in that Slide 49 in the far two right columns on the table, what you were those for if they were used at all.

A. Well, they weren't used at all for calculations that result in plume. These just reflect the potential volume available within one mile.

Q. Okay. Thank you. On Slide 52, on your far-right diagram, I want to -- first of all, I want to applaud you on those diagrams on the far right. That's a very good way of distributing, showing in a large area, a large vertical, where from the work you've done that you're seeing as being allocated.

I want to just make sure I understand: When you allocated by zone, I think you first said you did that by available porosity of each zone. Is that correct?

A. Yes. So, for example, if we had Zone 1 or 1A exhibiting an average porosity of X percentage across a specific interval, we would utilize that value to assign a fraction of the total porosity across all zones and correlate that to the fraction of acid gas that that would -- that would occupy that. The fraction being the fraction of the total 13 million standard cubic feet per day.

Q. When you say "the porosity," are you saying just the porosity, or the porosity thickness product?

A. I'm sorry, you cut out at the end. Porosity what?

Q. When you say porosity are you referring just to the porosity values that are averaged in that zone or are you referring to the porosity times that zone thickness?

A. So it would be the average porosity within that zone. So it could be feet of porosity or a percentage of -- an average percent porosity across that zone.

Q. Well, again, is this porosity times thickness for each zone?

A. Yes.

Q. Okay. Good.

And you said you scaled based on permeability. Could you explain how you scaled that?

A. Well, we just made zones that were -- where available data. Where we had available data, whether through injection tests or drill-stem tests to estimate some sort of permeability value, we would scale them literally by the permeability value, just as a way to scale zones, or the potential of zones based on the porosity, as well their permeability so we wind up with zones that have greater porosity and permeability receiving larger volumes of acid gas.

Q. Well, the permeability is very nonlinear to porosity, so I was curious how you would scale that nonlinearity from a storage capacity term to a flow capacity term. So I just -- I'm just very -- did you scale -- you have a firm number but you scaled it. I still don't understand how you did that.

A. Well, we just factored it by the permeability value in order to -- a situation where zones with greater porosity and permeability potential received greater volumes of acid gas.

COMMISSIONER ENGLER: No further questions. Thank you.

COMMISSION CHAIR SANDOVAL: Thank you. I just have a couple of quick questions.

CROSS EXAMINATION

BY COMMISSION CHAIR SANDOVAL:

Q. I don't even recall what slide it was, but I think it talked about the acid gas that's estimated to go into this well is 12 percent H_2S and 87 percent CO_2.

Would Lucid be willing to provide the OCD with reports on how much CO2 and H2S was injected on a regular basis?

A. I think that will have to be addressed by Lucid.

COMMISSION CHAIR SANDOVAL: Will there be an opportunity to do that, Ms. Hardy?

MS. HARDY: Sure. I can ask Mr. Eales to address that issue.

COMMISSION CHAIR SANDOVAL: Okay.

Q. And then I can't recall, it may have been addressed by Mr. Eales earlier: Are there already H2S contingency plans in place for the existing H2S assets that Lucid owns and operates?

A. Once again I think that would be something that Lucid, that maybe Mr. Eales could address.

MS. HARDY: Yes, I believe there are. And Mr. Gutierrez, I believe, also addressed that issue.

COMMISSION CHAIR SANDOVAL: Okay. With those questions, that's all I have.

Ms. Hardy, do you have any redirect?

MS. HARDY: I do not. Thank you.

COMMISSION CHAIR SANDOVAL: Would you like to call or recall your next witness?

MS. HARDY: Yes. I think we would like to go to Dr. William Ampomah next, and then have Mr. Gutierrez come back at the end to give a summary. Is that okay?

COMMISSION CHAIR SANDOVAL: Yes, that's fine.

MS. HARDY: Okay.

Let me get him over here. Here he is.

(Note: Pause.)

COMMISSION CHAIR SANDOVAL: Tells us when you're ready.

MS. HARDY: I'm sorry, you cut out, Madam Chair.

COMMISSION CHAIR SANDOVAL: I said please let us know when you're ready.

MS. HARDY: Oh, we're ready. Thank you.

WILLIAM AMPOMAH, PhD,

having been duly sworn, testified as follows:

COMMISSION CHAIR SANDOVAL: Thank you.

Please proceed.

DIRECT EXAMINATION

BY MS. HARDY:

Q. Can you please state your full name.

A. My Name is Dr. William Ampomah.

Q. Where do you reside?

A. Socorro, New Mexico.

Q. By whom are you employed and in what capacity?

A. I'm employed by New Mexico Tech, and I am a section head of one of the research groups at PRC.

Q. Have you previously testified at a Commission

hearing?

A. No.

Q. Can you please identify the document that's marked as Lucid Exhibit 5.

A. Yes. That is my CV.

Q. Is that a true and correct copy of your CV?

A. Yes, that is correct.

Q. Can you please briefly summarize your education and professional experience.

A. I have a Master's and PhD in petroleum engineering, all from New Mexico Tech. And I do have a Bachelor's degree in petroleum engineering from a university in Ghana. And since 2013, when I started working on my PhD, I have worked on CO2 injection-related research up until now.

MS. HARDY: Commissioners and Madam Chair, I tender Dr. Ampomah as an expert in petroleum engineering.

COMMISSION CHAIR SANDOVAL: Any objection, Ms. Bada?

MS. BADA: No objection.

COMMISSION CHAIR SANDOVAL: Any objections from the commissioners?

COMMISSIONER ENGLER: No objection.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: All right. The witness is provided as an expert in the field. Please proceed.

MS. HARDY: Thank you.

Q. Can you please identify the document that's marked as Lucid Exhibit 6.

A. Yes. That is a Simulation to Support Lucid's Proposed AGI Well Permit Application.

Q. Was the study prepared by you or under your direct supervision and control?

A. That is correct.

Q. And what is the purpose of your study?

A. So the purpose of the study was first to develop a geological model based on the data that we got from Geolex. And once we develop the geological model we do a simulation to look at the effect of the CO2 gas injection, the AGI gas injection that were in the Devonian. And we look at the plume movement and also the pressure distribution within the reservoir.

And we also looked at the effect of the injection on the mapped faults that Geolex provided to us, and we even went further to look at some of the geomechanical aspect to see whether it is safe enough to inject CO2 or to inject the AGI gas within the Devonian.

Q. Dr. Ampomah, what is shown on your Slide No. 2, the Geological Model Study.

A. On Slide No. 2 I'm showing you a 20 x 20 kilometer geological boundary with all the wells that we got from Geolex. They gave us the tops and then the bottom of each of these wells, and we used that to gear into the geological -- or the structural model that we used in the study.

And, uh, looking at the AGI Well No. 2 and the Striker well, the salt water disposal well. So we narrowed down to a 6 x 6 kilometer for our simulation model. And for this simulation model I must say we focused more on the AGI2 well and also the Striker 6 well.

Q. And what is shown on your Slide No. 3 regarding structural modeling?

A. On Slide No. 3 I'm showing you the result from the bottom and then the -- the top and the bottom that we got from Geolex with all the wells in there. We tried to use that to map out the structure of the Devonian.

And I show you some few data from the geological model that we did in terms of the grid, the number of grid cells and evidently the dimensions of the grid cells that we use in the study.

Q. And can you explain the spatial property distributions shown on your Slide No. 4.

A. On Slide No. 4 we got the table on the left from Geolex, and they did the porosity/permeability analysis, and they gave us the mean values and the ranges for the porosity and the permeability. So this is what we actually utilized in dividing all our zones, and tried to use this to calculate the porosity and permeability to help us with our simulation model.

Q. And what's shown on your Slide No. 5?

A. On Slide No. 5 I'm showing you the porosity and the permeability distribution based on the data that I showed on Slide No. 4. And I must say that if you look at -- so the A is the permeability distribution and the B is the porosity distribution. You know, when we are doing this geological property modeling, we try to make sure we are capturing the maximum, the minimum and then the mean that was given to us by Geolex for each of the individual formation.

And if you look at the porosity figure, you can see that clearly we've identified or isolated all the porous -- all the high-porous zones that we believe the AGI gas will be going in there.

Q. Slide No. 6, can you describe the properties that were utilized in initializing the modeling.

A. So I showed you the structure modeling, I've showed you the property modeling, and before we can move on with our simulation model we need to also look at the other fluid properties.

So for me when we talk about a saline aquifer such as the Devonian, in our model we assume that this is a brine-filled reservoir. So we do use 100 percent. We assumed 100 percent saturated brine for the water saturation, and we assumed it is in a hydrostatic equilibrium.

And also we use two components, the H2S and the CO2, and in the fraction we have 17 percent for the H2S and 83 percent for the CO2.

And one assumption that we made in this model is that the two gases all can dissolve in the aqueous state.

And we also got data from Geolex which shows that the irreducible water saturation is about 17 percent, and we utilized that to really build our permeability gas, how the fluid and gas is going to move with respect to the water that is already within the system.

Q. What boundary conditions were used in the Hydrodynamic model?

A. In this model we utilized some raw boundaries. The first one is the external boundary where we assume it is open boundary condition. And right at the well we impose several different injection rates, so depending on the scenario that we talked about, we have a specific mix that we impose on that. That is on salt water disposal well.

But on the gas injection well that is the AGI Well No. 2, we imposed 13 million SCF per day of the gas.

And one important parameter is the bottomhole pressure gradient that we imposed on the injector well, or let's say on the salt water disposal well. That is 0.629 psi per feet, which is consistent with the Shmin gradient within the area.

Q. And what were the simulation scenarios?

A. So on the simulation scenarios to respond to the objectives of the entire study, we've run several models. One of them is to look at the faults' characterization, and what we did with that was that we assumed the faults are transmissive so that fluid can move across and along the faults.

And the second model, the second scenario that we looked at was what is the effect on the modeling responses in the faults if permeable, or let's say if the fault has a transmissibility of multiplier to zero.

And we looked at the injection scenario, the effect of the salt water disposal well on the AGI well.

So we looked at several very different

injection scenarios.

The first one we looked at when the salt water disposal is operating to its maximum capacity of 32,500 STB per day; and we also looked at if the induction is 15,000 STB per day; and the last one was if the injection is 7,472 STB per day.

And I must say that the 15,000 and the 7,472, we got this from analyzing the historical data.

And let me point out that our Slide No. 7, uhm, the salt water disposal well had already injected for several years so we had to try to do (inaudible) before we started with the actual gas injection for the next 30 years. So I should have pointed out that.

Q. Slide 9, can you explain what is reflected in the simulation results.

A. So Slide 9, these are the results that I am going to show on subsequent slides.

So the first one I'm going to show you the simulation results when we assume the fault line is entirely closed. And I'm also going to show the results when the faults are open to flow.

And with each of those faults that I have described, I also looked at the effect of each of the injection rates that I made mention on Slide No. 8.

And I'm going to display the gas plume for each of these scenarios that I have described in terms of the lateral sense, and I'm going to show you the one that has the most lateral. You know, in terms of the distance is much higher on the modeling responses.

And I'm also going to show you the pressure that goes with each of these simulations that we conducted.

Q. What is shown on Slide No. 10.

A. Slide No. 10, I will start from the left. That is a salt water disposal injection well. And as I talked about on the previous slides, I talked about we run three different scenarios, and here we did it with closed faults, as I indicated on there.

So you see we are able to put in -- if we are operating the well, the salt water well on the maximum capacity, we are still able to put in the 32,000 STB per day of the water with the presence of the AGI well. Let me point that out. And also we're able to also put in the 15,000 STB per day, and that's shown in the black line. The blue line is the maximum capacity, and the green is showing you the injection of the 7,472 STB per day.

And on your right I'm showing you the injection rate for the gas.

So it tells that you in each of these scenarios that were run, we are still able to put in the

13 mmcf of gas per day within the AGI2 well.

Q. What is shown on Slide 11?

A. On Slide No. 11, once you look at it you can see clearly that these faults are really having some effect on the shape of the AGI gas that has been injected.

So let me start from the left, the top. That is when we are injecting. So there were two wells on there. The well that is right beneath the center where you see the plume of the gas, that is the AGI Well No. 2. And right to the right you see the salt water disposal well. That is the Striker Well 6.

And on the top figure on your left, we are showing here that we are able to put in 13 mmcf of the gas, and at the same time being able to put in the 32,500 STB of water within the Striker well. And you can see that the shape of the gas is actually controlled by the faults, and also by the water injection that is going on in the Striker well.

One thing to point out here is that, you know, if the gas moved across each of these faults that has been mapped, then it tells that you that we've caused some -- that means that there has been some deformation that might not okay.

But in this line you see that the gas is actually not moving across any of these faults, so it tells you that the 13 mmcf of the gas per day that is being injected within that area with the presence of the salt water well, there has not been any deformation, or I'd say these faults have not been critically stretched according to the data that we had and what their response is.

And like I said, the gas plume is also affected by the injection that is going on in the water disposal well. So that is -- if you look at when we are injecting -- on your right when we are injecting 15,000 STB per day, within the Striker well, you can look at the plume, the shape of the plume. And the same thing when we are putting in 7,472.

So you can look at the plume and you see that clearly, if you inject more then clearly is pushing the gas more into the northeast direction, but if you put in less it already significant changes on the plume with regards to the injection going on in the water well.

Q. And what is shown on Slide 12?

A. On Slide 12 I'm showing you the pressure distribution at the end.

And let me point out that on Slide No. 11 it was at the end of the 30 years of the gas injection. So on Slide No. 12, I am showing you at the end of the simulation; that is, at the end of the 30 year of the gas injection with different injection rates, I'm showing you the pressure distribution.

Now, let me start with the first one on the left. That is when we are injecting the salt water well to a maximum capacity of 32,500.

You can see that right at the AGI well within the middle, there has not been a significant change in the pressure at all, compared to that of the salt water well. You can see more pressurized build up right at the salt water well compared to that of the AGI.

So what this is telling me is that if we have to approach the AGI well at a capacity of 13 mmcf per day, there's no way we are going to build much pressure compared to data of the salt water that has been -- that's still on the Devonian injection.

So let's look at if the injection in the salt water well is reduced, clearly you can see on your right top that is when we are injecting 15,000 mmcf. You can see the pressure build up as we slow down a little in terms of the numbers, it has really slowed down somehow.

And the same thing goes for the 7,472 right beneath. That's right beneath on your left.

So this line is showing if these faults fauts exists, if these faults exists and they are closed, we are not really going to build a lot of pressure right on the gas injection well compared to that of the salt water disposal well. And even with the presence of the salt water disposal well compared to the maximum capacity we can still safely inject within the AGI2 well without causing any deformation or, let's say, these faults being critically stretched.

Q. And can you describe the simulation results with the faults open?

A. So on the faults open and the fault closed, we are able to put in the allowed injection at the bottomhole pressures prescribed, bottomhole pressure that is equal to the fracture at which the formation was tapped having some microfracs, and you can see we were able to put in all of these injection rates, the same form of the open and also form of the closed.

Q. And what's shown on your Slide 14?

A. So on Slide No. 14 is after 13 where I showed dissimilar plots for dissimilar figure for the closed faults.

So on this one you can see the shape of the plume of the gas that has been injected is actually -- there's no significant effect from the AGI well at all. But if this was open then it means the gas can really move across or, let's say "along" the faults. And you can see clearly that where the AGI well is located, you can see the shape is more or less like open. That is what you expect to see, and you can see that it is able to move across the faults.

So what does this mean? What this means is that if we have a fault that is open or closed, that changes the shape of the plume. And that tells me that a difference is right here.

Now, if these faults ar open the gas can move across the faults. Now, if these faults are closed, the gas cannot move across the faults.

Now, if I show you this plot, this graph, graphics, and it was with regards to closed faults, then definitely you can tell that these faults would have been critically stretched. But in this case you see that the gas wasn't able to move across the faults. That is very close to the injection area. So this analysis tells me that looking at either the fault is closed or the fault is open, based on the data that we have and based on the model that we've got, we don't see significant changes in terms of whether it is safe to drill here and inject the gas or not.

And on the bottom I'm showing you the pressure. The same way the pressure response you can see on the first -- below, down -- the figures that I'm talking about now on the far left. You can see there is no pressure build-up on the salt water well compared to that of the AGI well. So you see that the AGI well, based on the work that we've done, we believe is in a location that is safe enough to inject the allowable injection rate of 13 mcf per day.

Q. Can you describe the geomechanical models now.

A. So on the geomechanics, once we are done with the hydrodynamic modeling we looked at whether -- let's look at the geomechanics and see whether it's still safe.

So we've got this model so we respond to that question, but we still went a little bit further to look at the geomechanics.

So here I am showing some geomechanics that we utilized in the study.

Okay. So now, on the data I showed you on the previous slide, normally it doesn't really contribute a lot in terms of the effect on the geomechanics. What I am showing you here on Slide No. 16 is what really matters.

Now, the first one is we identified that within the area that Lucid would like to drill the well, that area is in the normal faulting regime. What that means is that the stress in the vertical direction, the vertical stress is higher than that of the Shmax in the horizontal direction and is also higher than the Shmin in the horizontal direction.

Now, what the Shmin means is that is the minimum pressure at which you will start to generate microfractures within the formation. So this data here that I'm showing you is very, very important. And we got some ideas from Matador when we met them. They were able to show us some few data points for us to be able to improve on our geomechanics modeling, and I believe we've done so, as I'll show you on subsequent slides.

Okay. So normally -- on the last slide, the model that I actually used to determine is the Mohr's circle analysis.

Now, here I am showing you the Mohr's circle.

Now, the red line that you see, the red line is the failure line. So if the circle is very close to the red line then that will tell you that we are in a state of failure.

But this one I took the grid block right at where we are injecting the AGI well at the end of the 30 years of injection, and based on the data what we have on the model and based on the result that we see, the circle is not close to the line. So this also reacts with the flood deck. Your pressures within that AGI well location, are still safe. You know, we are not close to the failure

line, at least based on the data that we have.
And let me say that we use the petroleum engineering software package to actually do this work.

Q. Can you explain what is shown on Slide 18.

A. So on Slide 18, as an engineer I always want to do due diligence. You know, to look at under the scenarios that you have given me, would it still be possible to breach the well and any adverse condition. Like I say, I'm not a (inaudible.)
So what we did was to assume -- you know, based on the program I was showing most of the plume, the plume that you see is mostly within the Zone 8, the Zone 8.
So what I did was: What about let's inject the gas into, all the gas into the Zone 8 and see whether we are going to cause any failure within the formation, within the area; or let's say going to cause any problems with regards to the faults that are present.
So talking to Matador, the last time we talked to them they were suggesting that if we -- the pressure gradient can move as far as -- the frontal pressure gradient can move as far as .5 psi per foot.
So what we did was to come up with three scenarios. The first one is we did a scenario where the bottomhole pressure constraint is at a maximum, that is

Shmax. That is .88 psi per foot.

And also looking at the min. That's the one that we use for all the states that are presented here.

And also looked at the minimum. That is .5. Assuming if the pressure constraint, the bottomhole pressure should have been drawn down all the way to .5, how is it going to impact on the injection within this Devonian Reservoir?

Q. What's shown on Slide 19?

A. On Slide 19 I'm showing you the injection profile from what I described on Slide No. 18.

So let me start with the gas.

So with each of the bottomhole pressure constraints that we used, the red line is showing the gas. We are still able to put in the 13 mmcf of the gas per day without any trouble.

And let me explain that, you know, if we put that the bottomhole pressure constraint and the upward pressure blowdown goes beyond the pressure constraint, you would not be able to put in that amount of fluid. And that is shown here.

On the bold line out there, that is the high and the mid water injection.

It shows you that if the bottomhole

pressure is about .88 psi per foot, or it is .63, you are able to put in the maximum 32,500 barrel STB per day.

Now, if the bottomhole pressure should not be .5 then you can see on the low-water injection line you cannot put in the 32 million -- the 32,000. You cannot put in the 32,000. That should be reduced to about 25,000.

So this tells me if the bottomhole pressure has to be at .5 we can still operate the gas well to its maximum capacity without causing any trouble, but there is no way we can operate the water well.

But if you look at the historical data, if you look at the historical data of the, uh -- of the, uh -- from the salt water well, you can see that they were able to inject to about 15,000 thereabout. So it tells me that the bottomhole pressure might not be quite right. It has to be within the Shmin, which we actually know.

Q. What's shown on Slide 20?

A. On Slide 20 I'm showing you the pressure profiles that goes with the slide on -- what I showed you on Slide No. 19.

So that is done with the red one.

So in all the scenarios I show you that the gas were able to inject 13 million -- the 13 million cf cubit feet of the gas per day.

Now, if you look at a pressure buildup, we are not -- based on the graphics that I showed you on the pressure buildup, we are not really building up a lot of pressure from the AGI well, but if you see the salt water well, we are actually building up some pressure within that area.

So all this is telling you that the AGI well can operate in a safe and sound manner.

Q. Can you summarize your conclusions based on the results of the study.

A. Based on the results, based on the data now available to us, given to us by Geolex, and based on all the modeling that we've done, we believe, and based on the results, it confirms that the proposed AGI well can inject, safely inject 13 mmcf per day of the acid gas over a 30-period year.

And based on the results that I showed, it's clear to say that the salt water well is actually bringing more significant pressure increment compared to that of the AGI, proposed AGI well.

And based on the work that we did, we did not see any impact of the AGI gas that has been proposed to put in the AGI2 well having any effect on the hydrocarbon production within the area.

And also the gas plume is not really moving that much. You know, it's about one mile, the maximum distance is about one mile. So we believe the gas that they propose to inject is within a very confined and secured area. And, like I said, the lateral extents of the plume is constrained within a safe region, and that confirms that the Devonian, which is where you want to put the well, is a good candidate for gas disposal or gas injection.

And I also talked about in different injection scenarios and even the completion schemes support the same containment of the injection gas within the acid -- AGI Well No. 2.

Q. And in your opinion does the proposed well present health and safety risks to nearby operators?

A. No, I didn't see that.

Q. And in your opinion will the proposed well result in waste or impair correlative rights?

A. No.

Q. In your opinion will the well adequately protect oil and gas producing zones?

A. Yes, it will.

Q. In your opinion is the proposed injection zone a good candidate for the injection of acid gas?

A. Yes.

Q. And will the injection of acid gas through the

proposed well protect human health?

A. That's correct.

MS. HARDY: I have no more questions for Dr. Ampomah. I would move the admission of Lucid's Exhibits No. 5 and 6.

COMMISSION CHAIR SANDOVAL: Any objection?

MS. BADA: No objections.

COMMISSION CHAIR SANDOVAL: Commissioners, any objections to the exhibits?

COMMISSIONER ENGLER: No objections.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: Lucid Exhibits 5 and 6 are entered into the record.

Do you have any questions, Ms. Bada?

MS. BADA: No questions.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have any questions for the witness?

COMMISSIONER KHALSA: No questions.

COMMISSIONER ENGLER: Yes, I do.

Good afternoon, Dr. Ampomah.

THE WITNESS: Hi, Tom.

COMMISSIONER ENGLER: I want to start with Slide 6. Ms. Hardy, if you could get me Slide 6, please.

MS. HARDY: Sure.

COMMISSIONER ENGLER: Thank you.

CROSS EXAMINATION

BY COMMISSIONER ENGLER:

Q. Yes. Thank you.

So on the third bullet item you said you assumed that it was able to dissolve into the aqueous phase. You did not do any calculations to show if it did or did not.

A. No. I know for sure that CO_2, based on our previous study and experience, that CO_2 definitely dissolve in the aqueous phase.

So like you said, yes, we can do based on our policies to come up with that, and we believe that based on that experience, we believe this is a good assumption.

Q. Did you look at if the acid gas, particularly the CO_2, went into some other mechanism of displacement or whatever else we have?

A. Yeah. So I did not present that resource here, but we do. Some of it will be in freed space, and others will be in the residual carbon, and others will be in a mineral drop-in. But I didn't put much detail into that for this day.

Q. So who did -- did you use the Schlumberger program on this one?

A. Yes. And that is why we cannot -- so the

Schlumberger software is not able to model * utilization (phonetic) in terms of the reactive transport, but it can do the solubility. It can also do the residual trapping, as well.

Q.   So your programming was then confined to only dissolution and trapping, correct?

A.   That is correct.

Q.   Exactly. On the fourth bullet on the bottom one, you have irreducible water saturation of 17 percent. You're in 100 percent water-saturated zone. How do you come up with the irreducible value?

A.   Like I said earlier, so Geolex gave us this number, and this number since -- right, in terms of based on some earlier work that has been done in some places or published in some places, so it was not a bad assumption.

So we trusted what they gave to us.

Q.   In your relative perm curves did you include a critical gas saturation?

A.   Yes. So if you can go to the last slide. Okay. So on the last slide -- let me see what we can see it clearly.

Now, we have the one with the X. That is for the gas. So right from when we started the gas injection right until, let's say, when the gas -- when water saturation started to, uh, reduce, yeah, we started looking at -- we started seeing the gas movement.

And it's not clearly shown here, but you can see that once we started injecting the gas then definitely all at once the water saturation started reducing, and you can clearly see the gas movement.

Q. I'm sorry. I'm glad you put them in there, because of the --

A. Okay. Okay.

Q. On Slide 11 --

A. Okay.

Q. -- for these figures, which layer are you showing?

A. So this one is the maximum, so I would say it's on 8.

Q. Okay. This is your slides for Layer 8, because that's the one with the maximum leakage (phonetic), right?

A. Yes.

Q. Your units are in kilometers, and where I appreciate metric, we deal in feet and acres.

A. Oh, okay.

Q. How many acres would you say is that plume?

A. You know, that needs to be calculated. I don't have the number. I can look through my stuff here to see if I do.

What I did was just to look at the maximum length. That is within 1 mile. So let's say two mile by, let's say, 1.5 mile. So there's going to be less than one mile. So it could be one or two miles by -- so we have two miles by, let's say, one mile.

So I would say less than 1.5 mile, or less than 1 mile, I would say it is about two miles square.

Q. What are you looking at?

A. So I'm looking at it in terms of from the center of the well right to the tip of the movement, the actual calculation and you get the final -- we need to submit the final paperwork. I can do that and tell you the true area of it. But I'm just looking at just even as two mile on the vertical sense and let's say one mile on the horizontal sense. That is what I'm just using now. But I can get you the exact area of the plume.

Q. So your esti- -- right now real quick and dirty is about a mile and a half, two miles on the north/south?

A. Yes. That is correct.

Q. On your Figure 14.

MS. HARDY: Slide 14.

Q. (Continued) We heard earlier today, that if these are normal faults and they have a throw or vertical displacement of a minimum of a 100 foot to up to 2- to 300 feet. Did you include that displacement in your model?

A. So, Tom, can we move on over to Slide No. -- I don't know whether you have it, but she can show you it on the screen, Slide No. 22.

So, you know, like, you know, I'm not a geologist but I see these are all vertical faults, and these are the exact faults that was related to us, and these were the exact faults that were utilized in the study.

Q. Right. But the positioning of the fault is coming from the traces, but remember there is a vertical displacement between up and down the throw from anywhere from 100 to 300 feet. So your layers should not be right adjacent to each other but displaced by that throw.

Is your model accounting for that?

A. No.

Q. So when you go back to, like I said, the figure for Slide 14, when you're looking at the open faults you don't really -- you can't really say that this is correct because you don't have that throw in there, and that's going to change the profile of the injection. Would you agree?

A. So, Tom, that, uh -- yeah, that is a good assessment. And what we actually did was to try to -- so the fault -- since we wanted to do more statistical analysis here, we tried to -- the faults, we tried to have the vertical sense of the faults to go through the entire

Devonian. So, like you're saying, if we have -- it will still be through there, because based on the assumption that we're looking at -- we're just looking at the seismicity of the faults. All right. So we tried to make sure the faults are going through the entire system.

Now, that is the assumption that we made, but what you are saying is correct.

Q. My worry is, or I guess my questioning is related to -- and there was an earlier question today about the composition of the faults, and what I'm seeing here is if the gas hits the fault it's going to migrate up that fault along whatever that possible fault trace is, and then it could cause a lot of problems.

So that's why I'm wanting to know how you handled this.

It sounds like to me you that you put the traces in but you didn't put the throw in.

A. Yes, we did not add any other properties to it.

COMMISSIONER ENGLER: Thank you. No other questions.

COMMISSION CHAIR SANDOVAL: Thank you, Dr. Engrel. I don't have any questions either.

Do you have any redirect, Ms. Hardy?

MS. HARDY: Just one question.

REDIRECT EXAMINATION

BY MS. HARDY:

Q. With respect to the displacement of the faults, are you confident with your conclusion still that the AGI well will not result in impairment of correlative rights or result in waste?

A. Yes. My analysis still goes that way, because if you look at the faults and you look at Zone -- if we go to Slide No. 4, it shows you clearly that we have a very good seal within this area. And the way we did it is to look at if these faults were just running through the entire system, you know. So, like Tom was saying, if there is a displacement, in terms of how we run on this model, in terms of the analysis, whether these faults are open or closed, based on what we've done here we believe it is still safe to put the AGI over there.

MS. HARDY: Those are all of my questions. Thank you.

THE WITNESS: Thank you.

COMMISSION CHAIR SANDOVAL: You have another witness for recall?

MS. HARDY: Yes, Madam Chair. I'd like to recall Mr. Gutierrez.

(Note: Pause.)

COMMISSION CHAIR SANDOVAL: Just a reminder, Mr. Gutierrez, you were sworn in earlier and that still applies.

THE WITNESS: Absolutely.

ALBERTO A. GUTIERREZ,

having been previously sworn,

testified further as follows:

FURTHER DIRECT EXAMINATION

BY MS. HARDY:

Q. Before we get to the summary of the application, did you hear the questions earlier that were asked of Mr. White regarding the H2S contingency plan?

A. Yes, I did.

Q. And is there an H2S contingency plan in place?

A. Absolutely. The current AGI1 could not operate without an operating H2S contingency plan in place, and as is stated in the C-108 we will revise and modify that, uh, plan to address the additional H2S that is anticipated with the HGI2 and the additional facilities which are related to HGI2.

I also wanted to emphasize one thing which the Commission may not be aware of because of the original Order.

There was not a very clear understanding of what the acid gas composition would be when the Red Hills AGI1 was initially drilled, so as a result of that the Commission added a requirement in the Order that every six months Lucid analyze either the inlet gas and calculate the TAG or actually analyze the TAG, which is what they've been doing, and report the average concentration for that six-month period, and then report any time there is a really significant change in that concentration or composition as a result of hooking in new wells or whatever.

To be very frank, we have done that for the last two years for Lucid with AGI1 and we've found very small permeability in the TAG composition. It's been running about somewhere between 85 percent CO2 to 88 percent CO2 and then the remainder H2S.

Similarly, you know, the AGI2 is projected to be like 96 -- or 94 and 6 percent, but -- we don't know exactly what that concentration may be, but the H2S contingency plan will accommodate that, and we will have a much better idea by the time the H2S contingency plans needs to be modified.

So yes, we anticipate fully modifying it to include AGI2.

Q. Thank you. Have you reviewed OCD'S recommended approval conditions for the well?

A. I have.

Q. Is it your understanding that Lucid has accepted those conditions?

A. Yes.

Q. And after the Commission issues its Order and before the AGI well is drilled will Lucid submit a modified H2S plan?

A. Yes, we would submit that to Carl's (phonetic) group and work out the modifications with them and make sure that it's approved. It has to be approved before we can use it.

Q. Let's look at the C-108 Executive Summary.

Can you summarize the important points of the C-108.

A. Yes. I'd like to, you know, emphasize that Lucid is requesting the authority to inject a supercritical compressed acid gas of approximately 5300 barrels a day maximum capacity into the AGI2 from between about 16,000 to 17,600 feet. We will not exceed the calculated MAOP and in fact are probably going to remain somewhere in the neighborhood of 1900 to 2000 pounds under the MAOP.

The independent evaluations that both Geolex and New Mexico Tech have done indicate that the maximum lateral dispersion of the plume will be somewhere between half a mile and one mile from the point of injection. The area that we are talking about that the plume would encompass over the entire time period, I know that was a question that was asked William, is something on the order of less than 160 acres in aerial extent, and there's no current production in the Siluro-Devonian Formation within at least three miles of the projected acid gas well. And again we only have one well that penetrates that zone, and it has been plugged off.

Uhm, the proposed injection zone is certainly capable of permanently containing the injected fluid.

And I want to add something to this, because there was a lot of discussion back and forth about whether or not these faults are sealed and whether they are potentially open, and I think it's important to understand that that may be a relevant case in the injection zone itself, but we know for a fact, because of the ability of these zones to maintain such radically different pressures and the underpressured nature of the Devonian at this location, that there really isn't a potential for acid gas migration along these faults, because, for one, the faults are definitely sealed within the caprock, or otherwise we wouldn't see, we wouldn't be able to maintain the kind of differential pressures that we see in the two zones.

And then, and most importantly, I have to say this, because, you know, what we did was try to simulate the most conservative approach using all of these fault traces, despite the significant complaints from my geophysicist that he didn't even believe that the majority of those faults even exist there.

So I just want to say that it is, I think, a very conservative look at the injection zone and the boundary of the injection zone.

The modeling methods which were used are accepted modeling methods for looking at induced seismicity, again overly conservative because they use only an aqueous fluid to simulate that slip, whereas, as David mentioned, you can see that the effect of the AGI itself because of the lower density of the fluid and the significantly lower viscosity of the fluid, it's not going to create much of a pressure difference. It's really controlled primarily by the SWD wells.

And so I think when you also combine that with the evidence that we evaluated relative to the pressure differences between the zones, the targeted injection reservoir is, in our opinion, an excellent reservoir and it will ensure that the injected acid gas will be contained within that zone and not affect overlying potential production.

Q. What are Lucid's requests of the Commission in this case?

A. Bottom line? We're asking for permission to drill, test, complete and operate the Red Hills No. 2 as specified in the application along with all the other supplemental information which has been provided.

We request permission to inject that acid gas at an MAOP of 48/38 and at a maximum rate of 13 million cubic feet a day, or barrel equivalent of something in the neighborhood of 5300 barrels per day for 30 years.

We believe that the well will enhance the reliability, we know it will enhance the reliability of the plant and the ability for it to add additional capacity to serve adjacent producers; and the proposed well will dispose of acid gas safely and effectively, and it assures the protection of surface ground water resources and correlative rights, and prevents waste as a result of the overall project, in addition to the significant environmental benefit yielded by putting somewhere in the neighborhood 5,000 barrels a day of CO_2 in the ground that would otherwise go into the atmosphere.

Q. Mr. Gutierrez, did you hear Dr. Engler's question for Mr. White earlier about the data he had relied on, and he referenced a spreadsheet?

A. Yes.

Q. If the Commission would like that information,

is Geolex willing to provide it?

A. Yes. I mean, I think he's talking about the supporting information for the fault-slip model and those files. We'd be happy to provide them. You know, we have not done that in the past, but I don't have a problem.

Q. Mr. Gutierrez, does the proposed well present health and safety risks to the other operators?

A. Uhm, no. As a matter of fact, I think it reduces those risks relative to other ways of handling the acid gas. But I think that with the current H2S contingency plan that is in place and the revision of that which is foreseen before we begin injecting into the AGI2, I'm confident that it does not present any health and safety risks; and furthermore, I don't think it presents any kind of a risk to the potential resources that overlie the injection zone.

Q. So will the proposed well result in waste or impair correlative rights?

A. No.

Q. In your opinion will it adequately protect fresh water?

A. Absolutely.

Q. And will it adequately protect oil and gas producing zones?

A. Yes.

Q. In your opinion is the proposed injection zone a good candidate for the injection of acid gas?

A. I think it's an excellent candidate, and we've used it on quite a few other wells, AGI wells in the area.

Q. In your opinion will the injection of acid gas into the proposed well protect human health and the environment?

A. Absolutely, because, as I mentioned, it reduces greenhouse gases and will safely handle the toxic and poisonous gas, H2S.

Q. What geologic factors will ensure the integrity and safety of the well?

A. All of the geologic factors that we talked about: the efficacy of the caprock; the fact that there is a pressure differential between the overlying zones and the injection zone which tends to keep the gas in place; the physical design of the well itself; and all of the procedures which are laid out in the C-108, in which the Division is well familiar that we follow when we install these wells, in terms of the monitoring and the testing that is done.

So all of those things combined will assure the integrity of the well and of the overall injection system.

MS. HARDY: Thank you. I have no further

questions for Mr. Gutierrez. I would move the admission of Lucid Exhibits No. 3 and 4.

COMMISSION CHAIR SANDOVAL: Any objection, Ms. Bada?

MS. BADA: Madam Chair, OCD has no objections.

COMMISSION CHAIR SANDOVAL: Any objections from the commissioners?

COMMISSIONER ENGLER: I have no objections.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: Exhibits 3 and 4 of Lucid are entered into the record.

MS. HARDY: Thank you.

COMMISSION CHAIR SANDOVAL: Ms. Bada, would you like to cross examine the witness?

MS. BADA: OCD has no questions for this witness.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have questions?

COMMISSIONER KHALSA: No questions.

COMMISSIONER ENGLER: No questions here.

COMMISSION CHAIR SANDOVAL: I just have a couple overarching questions.

CROSS EXAMINATION

BY COMMISSION CHAIR SANDOVAL:

Q. Have you reviewed, uh, OCD Exhibit 2?

A. I have.

Q. So it would appear that this proposed AGI is within -- maybe you can clarify for me. Is it within the half-mile buffer, the three-quarter-mile buffer of those faults?

A. I don't know that the faults are even there, Commissioner Sandoval, so --

Q. If you can just answer my question, though.

In the exhibit that was presented, I think the chart is in Exhibit 3, if you could just answer for me without the commentary: Is the proposed well within the half-mile buffer or the three-quarter-mile buffer of any of the faults on this piece of paper?

It would be incredibly helpful.

A. Yes.

Q. Okay. So I think you addressed, when Ms. Hardy asked you questions regarding protection of fresh water, all of that jazz, prevention of waste, but I guess I'm concerned about protection of public health and the potential for induced seismicity.

Do you believe that this injection well could, even potentially, increase or lead to induced seismicity?

A. No.

Q. And why is that?

A. Because the relative effect of this well, compared to the effect of the salt water wells in the vicinity makes its effect on the pressure negligible compared to those wells, except in the immediate vicinity of a well.

Q. But do you think that there could be a cumulative effect from all of the wells in the area plus this well?

A. Again, I mean that's what we have attempted to model with the fault slip analysis, and it doesn't indicate to me that that combined effect is likely to result in induced seismicity. And as Mr. White testified to, if you remove the well, the AGI, completely from the system, you know, the difference is less than 50 psi over 30 years.

Q. Do you think it would be, likeI, don't know, like adding one extra drop to the glass and it overflowed, potentially?

A. In my opinion and based on my experience and based on our review of all of this information, I do not believe that to be the case.

Q. So do you think that Exhibit 2 of the OCD's exhibit is flawed?

A. OCD's Exhibit 2 is the exhibit that shows just the location of the proposed well relative to the other wells in the area. I --

Q. Exhibit 3. Exhibit 3, which is the affidavit of Todd Reynolds where they express concerns about those faults and they talk about that kind of half-mile and three-quarter-mile buffer. And so I'm just trying to understand how this well is not a problem even though this affidavit is saying it could potentially be.

That's what I'm trying to understand, so if you could respond.

A. Well --

Q. Are you -- I mean, do you think that this information is flawed?

No. But if you look at the evaluation you can seen that it says the fault slip potential modeling shows that -- in this I'm reading from page 2 of that exhibit, where it says, "The fault slip potential modeling shows that these faults are at a low risk for a new seismicity, even related to the salt water disposal operation, and it's primarily due to the orientation of the faults."

And I would agree with that.

And he says that in following statement that, "Despite the low risk for a new seismicity, they present concerns relative to limited injectivity and potential confinement."

We modeled that in Mr. Ampomah's model, and

we don't believe that that is a concern here either.

So I do not believe -- at least in my reading of this affidavit does not lead me to believe that there is an unreasonable or excessive risk to induced seismicity, even in this exhibit, and certainly not in the work that we have done.

Q. Yeah. I mean, we can -- will you just read for me 10-A and explain to me about what you're saying, and how those two line up. I just want to understand, because our job is to make sure that any application that we approve is protective and preventive of waste, correlative rights, and human health and the environment. So we have to do our due diligence, and I'm just trying to line up the different pieces of data that we have and what you're telling me, and other pieces of data that I'm seeing.

So if you could just explain to me, directly answering the question, how 10-A, which has no new injection, which has no porosity or permeability allowed below 15,000 feet, and what you're saying.

I'm just a little lost here.

A. Well, I mean if I read that, it says "Given the concerns," that he lays out above. But the concerns that he lays out above, he says that the faults show a very low risk for induced seismicity.

So I think what he is saying, or what I

interpret what he is saying, I guess we'd have to ask him, but he's saying that he recommends that there be a setback or a half-mile buffer, and that you do not permit or allow the injection of fluids within that half-mile buffer.

And I don't know if that is his recommendation that he feels would remove all risk, because he's already saying that the risk is relatively low.

And furthermore, when you look at one of the conditions that OCD has imposed on, and that we have agreed to accept for the well, we're also going to monitor the seismic activity right on the site. So I believe that we will have a direct measurement of a potential problem, should it occur; however, all of the evidence and all of the data that I have reviewed, you know regardless of whether his recommendation is that you stay away from these interpreted traces, which may or may not be faults, I do not believe that that is necessary to prevent slip along those faults as a result of injection.

Q. All right. Are you aware of any induced seismicity in that region?

A. In the immediate vicinity of the plant, no, I am not.

Q. Okay. If that monitoring station goes in, OCD Exhibit 2, believe. Exhibit A? I can't remember.

Exhibit 1.

And maybe this is a question for Mr. Eales, but if that station were to detect any seismicity or any activity in the area and it was believed that that well was causing or contributing, would Lucid be willing to either reduce injection or shut that well in?

A. I think that would the first thing I would recommend. I would first recommend trying to figure out what's causing the induced seismicity, if it does exist, because the overwhelming evidence that we have is that the salt water wells in the area are what really produce the bulk of the pressure increase, as opposed to the relatively minimal injection that's proposed by this well.

So I guess that you'd have to come up with a plan for determining what the induced seismicity is resulting from, and that plan may well involve shutting the well down for some period of time and seeing if that induced seismicity continues, or maybe shutting or reducing some of the water injection in the area, which is more likely to produce induced seismicity than the injection of acid gas.

COMMISSION CHAIR SANDOVAL: Okay. I have no further questions.

Ms. Hardy, do you have any redirect?

MS. HARDY: Just a couple of very quick

questions.

REDIRECT EXAMINATION

Q. Mr. Gutierrez, this NGL affidavit that is OCD Exhibit 3 you have received questions about, --

A. Yes.

Q. -- was any other data or modeling provided with the affidavit?

A. Not that I have seen.

Q. And NGL operates water disposal wells in this area generally, doesn't it?

A. Absolutely.

Q. And it submitted an affidavit requesting other wells not be permitted in certain areas?

A. Yes. In my own opinion, this was a pretty thinly-veiled attempt to reduce competition for salt water wells. That's my own opinion.

Q. And has the modeling that Geolex performed and the modeling that was performed by New Mexico Tech, addressed the potential for induced seismicity such that you're confident the well won't harm the public health and environment?

A. Absolutely.

MS. HARDY: Those are all of my questions. Thank you.

COMMISSION CHAIR SANDOVAL: Thank you, Ms.

Hardy.

Do you have any other witnesses?

MS. HARDY: I could recall Mr. Eales, if now would be the appropriate time to do that, for the couple of questions that the Commission has.

MR. GUTIERREZ: Matt said I could answer on it, so if you want to ask me the questions, I...

MS. HARDY: Sure. Is that acceptable, Madam Chair?

COMMISSION CHAIR SANDOVAL: Yes, if he's able to answer those questions.

MS. HARDY: Okay.

FURTHER REDIRECT EXAMINATION

BY MS. HARDY:

Q. Mr. Gutierrez, did you hear the Commissioners' questions earlier for Mr. White regarding reporting of the gas that's being injected into the well?

A. Yes. As a matter of fact, currently the AGI1 is not required to report injection parameters like many of the other wells are -- and I think it's just a function of when that Order was drafted -- but the well is required every six months to report acid gas composition, because it was uncertain what that acid gas composition would ultimately be. And Mr. Eales has indicated to me that he would be willing, Lucid would be willing to do the same kind of reporting on this well.

Q. And is it your understanding that with respect to the seismic monitoring that Lucid would be willing to work with the Division regarding potential seismic events that could be identified if they occurred?

A. Absolutely. As a matter of fact, Lucid has already agreed to fund the construction of a seismic monitoring station there, that would be worked out in conjunction with New Mexico Tech, monitoring those data, as part of the sitewide -- I'm sorry, the statewide system of monitoring seismicity.

MS. HARDY: I have no other questions. I believe those were the topics I intended to ask Mr. Eales about. I think that Lucid's --

COMMISSION CHAIR SANDOVAL: Ms. Bada, Any other questions?

MS. BADA: No questions.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have any questions?

COMMISSIONER ENGLER: No questions.

COMMISSIONER KHALSA: No questions.

COMMISSION CHAIR SANDOVAL: All right. All right. (Inaudible)

FURTHER CROSS EXAMINATION

BY COMMISSION CHAIR SANDOVAL:

Q. Do you know if Lucid would be willing to report at some frequency to the OCD the amount of CO_2 that has permanently sequestered into the ground?

A. Uh, yes, I would presume that that would be something that they would be willing to do. And as a matter of fact, Lucid is pursuing, at least evaluating the ability to develop a more rigorous monitoring and verification, MRV plan, in order to be able to obtain some available credits for storage of that CO_2. So that would in and of itself require that kind of reporting.

But with the reporting that the Commission has been requiring of all AGI wells on a quarterly basis, that would be information that would be easily derived from that information which is being provided.

Q. So that's a yes?

A. That's a yes.

Q. All right. And then kind of circling back to my question, you seem to defer it a little bit to Lucid but not...

If the AGI was found to potentially cause or contribute induced seismicity, would Lucid be willing to work with the OCD and either pull back injection or shut in the well, again if it was found to cause or contribute, so you don't need to speculate.

And I just want a yes or a no.

A. Yes.

COMMISSION CHAIR SANDOVAL: Thank you. I have no further questions.

MS. HARDY: Madam Examiner, I think Lucid's case is concluded. I have no more witnesses at this time.

COMMISSION CHAIR SANDOVAL: Thank you. Five-minute break, and come back at 3:06 and we will proceed with the Division's case.

(Note: In recess from 3:01 p.m. to 3:08 p.m.)

COMMISSION CHAIR SANDOVAL: All right. Let's start back up.

Ms. Bada, would you like to present your first witness.

MS. BADA: Yes, Madam Chair.

Also, could you enable me to share content?

MS. SANDOVAL: Yes. Give me a second.

You should be able to now.

MS. BADA: Okay. Okay.

I don't know if it's going to let me do this or not.

Yeah, there we go.

COMMISSION CHAIR SANDOVAL: All right.

MS. BADA: I'd like to call my first witness, Phillip Goetze.

Thank you.

PHILLIP R. GOETZE,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. BADA:

Q. Please state your name for the record.

A. My name is Phillip Goetze.

Q. Where are you employed?

A. I am employed by the Oil Conservation Division, the New Mexico Energy, Minerals and Natural Resources Department, State of New Mexico.

Q. What is your position with the Oil Conservation Division?

A. Currently I am the UIC manager for the Division staff which oversees compliance and reviewing applications for UIC Class II wells.

Q. And what are your specific responsibilities?

A. Provide, uh, both oversight and training, as well as provide some sort of program orientation for the quality control, and assist staff in solving issues for more complex problems, as well as advise districts in issues regarding well completions that are injection control wells, as well as other items.

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

A. Yes, I have.

Q. And did you prepare a Curriculum Vitae?

A. Yes, I did. It is Exhibit No. 4. Currently it shows -- go ahead.

Q. Is Exhibit 4 shown on your screen?

A. Yeah, I'm getting ahead of my lawyer.

Q. Okay.

A. And yes. I have seven years plus with the Division and have worked from the position of being a hearing examiner and then doing a lot of the underground injection control work. Prior that I was involved with both environmental and production in the oil and gas industry, mineral industry. And with that, United States Geological Survey, as well as the Bureau of Land Management in their oil and gas leasing, as well as assessing reservoir structures and determining geologic structures.

I have also had expertise in doing shallow seismic, reflection and refraction seismic.

And then of course the years of doing environmental work which all the way through to installing deep wells at Los Alamos to doing Phase Is.

Also I'm a Registered Professional Geologist in several states, and also have certification regarding health and safety.

Oh, and I'm a graduate of New Mexico Tech with a degree in geology.

MS. BADA: All right. Move the admission of the OCD Exhibit 4 and request that Mr. Goetze be recognized as an expert in the field of petroleum geology and underground injection.

COMMISSION CHAIR SANDOVAL: Ms. Hardy, do you have any objection to either Exhibit 4 or Mr. Goetze being, uh...

MS. HARDY: No objection.

COMMISSION CHAIR SANDOVAL: Commissioners, are there any objections?

COMMISSIONER ENGLER: No objection.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: Mr. Goetze is recognized as an expert in the field and Exhibit 4 is entered into the record.

Q. Mr. Goetze, have you reviewed Lucid's application?

A. Yes.

Q. And what is your opinion of the application?

A. OCD generally favors Class II wells for disposal of treated acid gas. Lucid already operates an acid gas injection valve at the same facility. Its application is for approval of a second well at this facility, which is supportive of OCD's current effort in two ways:

One, we would like to permit disposal injection in the Delaware Mountain Group especially in targeted formations for hydrocarbon development directly under them in the Bone strings and Wolfcamp.

And second, we like to have these acid test wells have a partner onsite. Historically when we have had a single (inaudible) repercussions have been significant to the production, as well as to the environment with regards to the flaring of gas.

Q. Were there --

A. And -- go ahead.

Q. Were there concerns with the application and the proposed location and depth of this proposed well?

A. Uh, yes. I have included two exhibits for the consideration of the Commission.

Exhibit 1 is a map which we put together showing existing permits in the Devonian, and Exhibit 2, which has been talked about a bunch, is an exhibit from a case, two cases actually, involving NGL and its effort to rescind, withdraw two Devonian wells that they were seeking for approval.

Q. Do you want to refer to Mr. Reynolds' affidavit any further, Mr. Goetze?

A. Well, going to Exhibit 1, what we're looking at is a summary of the activity in the area. You see a lot of completion with regards to the well, the winding up of the production wells, a lot of Bone Springs production.

We have the facility, and then we have a shotgun pattern, one might say, of applications for disposal in the Devonian.

The Division in its effort to get out of shallow injection and go deeper selected Devonian, and the Commission is quite aware of this. At this time what we wanted to show as a demonstration is that we have several wells in this area which were both in close proximity to themselves, but also showing that the future consideration, the density of what we do in this area will have an impact on what this well and how it performs if we get too carried away.

Exhibit No. 2, which is the Affidavit of Tom Reynolds, who is an expert witness on behalf of NGL, was brought to us at the request of NGL in Cases 20141 and 20142. In both these cases the Applicant had made a C-108 application for two wells in the Devonian in proximity to the well we're talking about today, and with that they presented an affidavit and a witness, which unfortunately was not Mr. Reynolds, and to that end requested that the two wells -- if we go to back Exhibit 1 you'll see that the -- excuse me, Exhibit -- yeah.

The well to the northwest of the Red Hills

AGI1 and AGI2, the Trident and the Sparrow were the two wells that they requested that the Order for it be withdrawn or not considered and that the Application be dismissed.

We received this information, and based upon the testimony of another expert by NGL, the concern that was relayed to us and testimony that NGL was concerned more about impact to correlative rights and did not really focus on the potential for induced seismicity.

The other item I would add to that is that in testimony in cross and trying to get NGL to provide some sort of statement as to their opinion on whether there would be migration along the fault system itself should salt water disposal reach it and go to, say, deeper formations or into the Precambrian, there was no opinion given either way.

(Note: Pause.)

COMMISSION CHAIR SANDOVAL: You have to repeat yourself, Ms. Bada. I apologize, I didn't hear you because of some background noise coming from you, so would you repeat.

MS. BADA: Madam Chair, I would move the admission of OCD Exhibits 2 and 3, the map and the affidavits.

COMMISSION CHAIR SANDOVAL: Any objections, Ms.

Hardy?

MS. HARDY: No objections.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have objections?

COMMISSIONER ENGLER: No objections.

COMMISSIONER KHALSA: No objection.

COMMISSION CHAIR SANDOVAL: Thank you. OCD Exhibits 2 and 3 are now entered into the record.

Q. Mr. Goetze, what standards do you apply when evaluating whether a Class 2 UIC well should be approved?

A. We do the standard language of what we look at, and that is does it, first: Prevent waste? Does it protect correlative rights? Does it protect the public health and the environment?

And that includes the essential portion of the program which is the protection of underground sources of drinking water.

Q. Have the Oil Conservation Division and Lucid agreed to conditions that ensure compliance with these standards.

A. Yes. We have talked with Lucid since this project started at the end of 2019. It has come back several times with reiterations as have been previously testified to; and in doing so we came up with some conditions.

Q. Do you have an exhibit listing those conditions?

A. Yes, I do, and that was Exhibit 1.

The Commission should be familiar with most of the content of this. These are many of the same criteria we apply to any Order issued or provided by the Commission. Many of them are now our standard operating procedure, and hopefully we've improved them since the last use in the Salt Creek case.

To that end there are two unique conditions in this exhibit that we put together. Finding that we do have a situation, fault systems and questions about induced seismicity, the OCD requested that one of these conditions be inclusion of a public-access seismic station at the facility. We are working with New Mexico Tech as to what the standards are and what issues there may be part of it. We felt that considering we have other arrays in the area which are privately owned but may not be available, that one station would be at least a good start.

The other condition which is very unique in this kind of situation is because the existing well is a shallow well injection that we include criteria for the well to be completed such that this does not become an issue either drawing through, or later in the life of the well when the S-gas may impact cement and casing quality of the deeper well.

Q. Do you have any other recommendations?

A. Uh, I would -- in light of what's happened with the one previous, the Salt Creek, I would ask the Commission to also stipulate some sort of timeline for the Order, the authority to inject, and maybe the ability for administratively to be extended. I think in the case of Salt Creek we did not include that. We have done that in prior Orders by the Commission, in order that there is some sort of at least period to review should it be extended.

Other than that, no more.

Q. In your opinion will the proposed conditions provide adequate assurance that the proposed well will not cause waste or harm correlative rights, or will protect public health and the environment, including underground sources of drinking water?

A. Yes.

MS. BADA: I have no further questions.

(Note: Pause.)

COMMISSION CHAIR SANDOVAL: Sorry. I was muted.

Ms. Hardy, would you like to cross the witness?

MS. HARDY: I have just a couple of questions, Madam Chair.

Mr. Goetze, can you hear me?

THE WITNESS: I can hear you. Good afternoon.

MS. HARDY: Okay. Thank you.

CROSS EXAMINATION

BY MS. HARDY:

Q. If you can please look at your Exhibit No. 2, which is the map prior to proposed wells.

A. Hmm, yes.

Q. Within the red circle surrounding the AGI wells 1 and 2, are some of the wells identified here related to permits that have been withdrawn?

A. The only two which have been withdrawn are Trident and Sparrow. The others are pending applications which either have been protested, or in the case of the two that are in close proximity we have concerns about because this would make absolutely no sense in issuing two permits in close proximity.

Q. Okay. So those permits that are pending, they may or may not be granted. Is that fair?

A. That's correct.

Q. Mr. Goetze, if you could please look at the OCD Exhibit 3, Affidavit of Todd Reynolds. I think you said a few minutes Mr. Reynolds that didn't actually testify. Is that correct?

A. That is correct.

Q. And is it correct that -- I think you said NGL's testimony that they did provide didn't focus on new seismicity.

A. That is the way it's written in the record in the transcript.

Q. And is it correct that the Division didn't make any determination regarding the potential for induced seismicity based on the information that NGL provided.

A. We do not have the expertise for that. Other people provide us with the fault-slip models. We look at the criteria included in it and go upon the recommendations. However, I will say that it is quite unique that the 1/2 mile and the 3/4 mile are the radius. 3/4-mile radius is what we use informally, based upon the transcripts and records of initial applications, and that the 3/4 mile represented what most of industry stated as the radius of influence for a well 20 to 30 years, going around 30,000 barrels a day injection.

So these numbers are based upon several applications that were heard before both the Division examiners as well as commissioners.

Q. And the Division's Orders in these cases, basically just dismissed NGL's applications at their request. Is that correct?

A. Yes. As an Applicant you can actually withdraw your application.

MS. HARDY: Thank you. Those are all the questions that I have. Thank you.

COMMISSION CHAIR SANDOVAL: Thank you.

Commissioners, do you have questions for the witness?

COMMISSIONER KHALSA: I have one question.

CROSS EXAMINATION

BY COMMISSIONER KHALSA:

Q. Good afternoon, Mr. Goetze.

A. Good afternoon, Commissioner Khalsa.

Q. One quick question. What is OCD's regulatory authority under the AGI permit if microseismic is detected by your array with a particular well?

A. Would you repeat that. You broke up in the middle of it.

Q. Sorry. What is OCD's regulatory authority under an AGI permit if microseismic events, induced seismicity events are detected by a seismic array close to the well?

A. Currently OCD has a pending case regarding spacing and induced seismicity; however, the EPA has given us authority per the general discussion of protection of the environment, that incidences of induced seismicity that we may have the authority to respond either through direct action or, in this case, typically what we do is we are hoping that Commission would give us some guidance. We are very limited at this time but we are trying to develop a pathway similar to what Texas has in an effort to restrict -- uh, start a response, especially with the 2-5 to 3 and of course the 3 in most states require some sort of remedial action, as that being magnitude.

COMMISSIONER KHALSA: Thank you. No further questions.

COMMISSIONER ENGLER: This is Tom Engler. Good afternoon, Mr. Goetze.

THE WITNESS: Good afternoon, Mr. Engler.

CROSS EXAMINATION

BY COMMISSIONER ENGLER:

Q. Couple of quick questions. You heard today a couple potential drilling plans from Lucid. Do you have any opinion on which one of those -- will they both suffice or do you have a preference?

A. We've had mixed results with both. We've had twinning of wells where people tried to put the cement in without doing the casing upgrade and it had terrible results. And we've had them do both the upgrade of casing and they have been able to land the cement well.

As OCD we would always like to go the route of the safest.

Q. Thinking about twin wells, I have a concern

about drilling a twin well 200 feet while drilling through a zone that's been injected. Have you seen, again in twin wells, have they done any special precautions while drilling when they go through those zones?

A. It is my understanding based upon the folks in the field, that yes, they do take it to a much higher standard. We do have, as you know, situations in the Pennsylvanian, where we do have high H_2S.

So, yes, I've seen a level of much higher confidence when you are knowingly going to drill into a target like this.

Q. Let's see. I think -- one last question, going to your -- well, it's the map with all the circles, Exhibit 2.

A. Okay.

Q. So there are existing wells, there are applied wells, there are wells that are being -- or that were removed or dismissed.

I guess if I was trying to come up with what this is telling me, is that there is significant interest in injecting in the Devonian, and there is significant issue with overlap.

A. Uh, yes, sir. We have over 500 applications for Devonian, and we have overlap. We do have an SWD layer which we can provide to you, but one of the things that was originally of concern, and we still have a pending case on, is the proximity of these wells together.

The approach of the fault slip was a big step for us, using a model, the Zoback model, or at least something that's industry standard and can be reproduced, even though there still is some questions about how they are filled out, and...

But the proximity of these wells together creates a management issue, and historically we've not had much of an authority to do it, and actually one Order we've said you can drill within a 100 feet of another person and we don't care. But this was from a period of time when we had very few of these wells and most of the disposal was very shallow. The horizontal world has created such demand that doing shallow was not the alternative, and of course the recommendation to go to Devonian, which was originally in our primacy agreement was selected as the alternative.

COMMISSIONER ENGLER: Thank you. No further questions.

COMMISSION CHAIR SANDOVAL: Thank you.

Mr. Goetze, I just have a couple of questions for you.

CROSS EXAMINATION

BY COMMISSION CHAIR SANDOVAL:

Q. So what you're saying is, I think it's called the Minute Man SWD1, and then the other application that seems to be overlapping and nearby, those would probably not be moving forward?

A. Are you looking at the Minute Man and the Striker?

The Minute Man has been approved. It predated this application.

Q. Okay.

A. It does have a limiting volume on it, I believe.

And the Striker 6 SWD2 is somewhat limited, basically because of its completion. The, uh, bottom -- it does not have an open hole, it has a slotted liner in the injection interval, and its casing -- or I mean its tubing design will limit how much it can inject with regards to pressure.

Q. Okay. So do you have any concerns about that being so close to the Red Hills?

A. The Striker 6? Not at this point. If we were to get a request for a tubing size increase, then yes, I would be opposed to that, changing the current operation.

Q. Thank you. In this general vicinity in this state, have we seen a new seis- -- or have operators, or have we gotten any reports of induced seismicity?

A. Not that I'm aware of. What NGL has presented in their applications, for instance for the Sparrow and the Minute Man, their array showed more of regional and we consider background, nothing that would be identified as related to induced seismicity.

Q. Okay. I mean a yes or no question.

Do you believe that both acid gas injection and salt water disposal could potentially contribute to induced seismicity? If there were some sort of case of induced seismicity, do you believe that it could potentially come from SWDs or AGIs, or a combo of both?

A. (Note: Laughter.) You can't answer yes or no to an or.

Q. Two questions.

A. I think the greater drive on this, and this is something for the Commission to think about, is that the salt water disposal represents a moving liability in the sense that they may change operators and operations.

The AGI wells tend to be locked to a facility, a surface facility. The fact that they share injection intervals, my concerns would be primarily with salt water disposal, just based upon the characteristics of what's being put down the hole.

But it's one of these things where we will be then looking at is what we do for enhanced recovery, is that you have an area permit, an area where you're going to have a sole (phonetic) be for that injection, dedicated, say, to that facility, that acid gas processing facility.

And otherwise I would be suggesting prudence to move anything away that had produced water.

Q. Thank you. Could you just elaborate for me for a second on the -- you mentioned a proposed, I don't know what number -- 19th condition regarding timeline for the Order and authorities.

Could you just elaborate a little bit more on what you mean and why.

A. Uh, let's see. Which one do you want me to...

Q. You had mentioned a potential 19th, additional --

A. Oh, okay. What happened with Salt Creek is there was no -- typically we put one year in that Commence Drilling. And we tend to do this with all our permits. It created an issue with Salt Creek because we put in a timeline for the placement of the second well but we didn't put any timeline in for the first well, which was the shallower well to be drilled.

So in order to avoid -- and lawyers went back and forth on this because it was a little confusing as to what was being extended and what wasn't.

In light of the Division being able to keep track of these wells and the ability to make sure that if this well is not drilled that there is a means by which the operator can come back either to Commission or to the Director for an extension, that would be beneficial.

The only thing with that: With all of our extensions we ask that the area of review of the original application for both wells that penetrate, as well as any change in the affected parties, be reviewed and documented and provided.

COMMISSION CHAIR SANDOVAL: Thank you. That is all of my questions.

Ms. Bada, do you have any redirect?

MS. BADA: I don't have any redirect, but I ask that an exhibit, OCD Exhibit 1 be admitted into the record.

COMMISSION CHAIR SANDOVAL: Ms. Hardy, any objections?

MS. HARDY: No objection.

COMMISSION CHAIR SANDOVAL: Commissioners, any objections?

COMMISSIONER ENGLER: No objection.

(Note: Pause.)

COMMISSION CHAIR SANDOVAL: Exhibit 1 for OCD is now entered into the record.

Ms. Bada, do you have any other witnesses?

MS. BADA: We have no other witnesses.

COMMISSION CHAIR SANDOVAL: Thank you.

Do any of the parties wish to --

MS. HARDY: Madam Chair, if I could possibly, I do have a question for Matt Eales to clarify an issue, if I could call him very quickly.

COMMISSION CHAIR SANDOVAL: Yes.

Just a reminder, Mr. Eales, you were sworn in earlier and are still under oath.

ROBERT MATTHEW EALES,

having been previously sworn, testified

further as follows:

FURTHER EXAMINATION

BY MS. HARDY:

Q. Mr. Eales, have you heard the testimony and the questions regarding the potential for an induced seismicity and the monitoring of that?

A. Yes, I have.

Q. How would Lucid propose to handle induced seismicity if it's recognized by the monitoring?

A. Thank you. As Mr. Goetze referred to earlier, we have been in conversation for some time. We had contracted with Geolex to do a study of this location. They found no problems, or they found what was presented.

In an abundance of caution and in our

desire to be protective of the environment and health we then went above and beyond and also contacted NMT to do an independent study of the same area, and, as you have heard, they came to the same result independent and separately.

So we feel very good about the fact that the AGI has -- the number was 1.2 percent of the overall total volume of the area, and everything we've seen is that the acid gas wells have a much lighter effect than SWD wells.

So in our acceptance of the ability to monitor on the surface -- again we are doing that out of an abundance of caution. We don't feel that it's necessary, we're are not aware of induced seismicity of the area, but again we want to be good stewards and work with OCD.

The only thing I would ask is that if there were any findings that it not immediately be assumed to be the 1.2 percent effect from our AGI but that we look at the entire area. And as you heard in other cases or other testimonials the SWDs definitely have the higher impact.

So we would just ask that OCD consider that, and if we do find any problems with the seismic that we work together with the other operators in the area.

MS. HARDY: Thank you. That was my only question.

THE WITNESS: Thank you.

COMMISSION CHAIR SANDOVAL: Ms. Bada, do you have any questions?

MS. BADA: I do not, Madam Chair.

COMMISSION CHAIR SANDOVAL: Commissioners, do you have any questions?

COMMISSIONER ENGLER: No.

COMMISSIONER KHALSA: No questions.

COMMISSION CHAIR SANDOVAL: All right. Thank you.

(Note: Pause.)

Ms. Hardy would you like to make a brief closing statement?

MS. HARDY: Yes. Very briefly. Thank you.

The proposed Red Hills AGI2 will allow Lucid to expand its treatment capacity while also serving as a redundant well. The well will also provide environmental benefits, including the sequestration of CO_2 and potential emissions credits.

As Lucid's witnesses have explained, the proposed well will protect human health and the environment and will not result in waste or impair correlative rights. Lucid has also agreed with OCD's recommended approval.

So Lucid has satisfied the criteria for approval of its proposed well and our request is that the Commission grant its application.

Thank you very much.

COMMISSION CHAIR SANDOVAL: Thank you.

Ms. Bada, would you like to make a brief closing statement?

MS. BADA: Madam Chair, OCD simply asks that if the Commission chooses to grant the application that it do so with the conditions that OCD has recommended.

COMMISSION CHAIR SANDOVAL: Thank you.

The record of this application 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 so the administrative adjudicatory deliberations exception to the Open Meetings Act, Sections 10-15-1J to deliberate in Case 20779.

Is there a second?

COMMISSIONER ENGLER: Second.

COMMISSION CHAIR SANDOVAL: May I have a roll call?

MR. LOZANO: Yes, Madam Chair.

Commissioner Khalsa?

COMMISSIONER KHALSA: Yes.

MR. LOZANO: Commissioner Engler?

COMMISSIONER ENGLER: Yes.

MR. LOZANO: Chair Sandoval?

COMMISSION CHAIR SANDOVAL: Yes.

The motion passes unanimously. The Commission will now close the session and the record. The public may remain on the meeting on the closed session and wait for the Commission to reconvene.

Thank you.

(Note: In recess from 3:51 p.m. to to 4:35 p.m.)

tc All right. Okay. Now that we have everyone, the Commission meeting and the record is now open at 4:35. The discussion during closed session was limited to deliberation in Case No. 20779.

Is there a motion?

COMMISSIONER ENGLER: Yes, Madam Chair.

I motion to approve the application to inject acid gas into the proposed well AGI2, subject to the following conditions as outlined in OCD Exhibit 1:

1 through 5 are still the same.

Under No. 6, the last sentence after what's there is "This report shall include composition and volume of the acid gas injected into the well" as an addition to 6.

No. 7 through 17 is as written previously, is the same.

No. 18, "The operator shall install, operate and monitor for the life of the permit a seismic monitoring station or stations as directed by the State Seismologist at The Bureau of Geology." That last part is new. Then the rest is the same: OCD shall be responsible for coordinating with the State Seismologist, New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment required to perform the procedure and monitor the data.

There is a couple of new ones we are adding.

No. 19: The injection authority herein granted shall terminate two years after the effective date of this Order if the operator has not commenced injection operations. The Division Director upon written request of the operator submitted prior to the expiration of this Order may extend this time for good cause shown.

No. 20: In the event Lucid transfers ownership of the well, Lucid shall seek approval of such change in ownership from the Division pursuant to 19.15.9.9 NMAC.

And the last one, No. 21: After 30 years from the date of the Commission's Order in this case, the authority granted by this Order shall terminate unless applicant or its successor-in-interest shall make application before the Commission for an extension of its authority to inject.

That is the end of my motion.

COMMISSION CHAIR SANDOVAL: Is there any discussion as to...

MR. LOZANO: Second.

COMMISSION CHAIR SANDOVAL: I second that motion.

Is there any discussion as to the motions that were proposed?

Dr. Engler?

COMMISSIONER ENGLER: Yes. I feel like this proposal and this approval demonstrated protection of correlative rights, prevention of waste, as we all know, and also meets the health and safety/environment that we all are concerned about.

So I think under those main items I feel that this was a very compelling.

COMMISSION CHAIR SANDOVAL: I agree with what I think Dr. Engler has said.

Some of those conditions are in line with Orders that have been issued for acid gas injection wells over the past year, so this keep things consistent with those authorizations.

All right. Mr. Lozano, would you do a roll call, please?

MR. LOZANO: Yes, ma'am.

Commissioner Khalsa, do you approve the motion?

COMMISSIONER KHALSA: Commissioner Khalsa. I approve the motion.

MR. LOZANO: Commissioner Engler?

COMMISSIONER ENGLER: I approve the motion.

COMMISSION CHAIR SANDOVAL: I approve the motion, and the motion passes unanimously.

The Commission directs Ms. Hardy to draft and circulate a Proposed Written Order of the Commission and send the Order to Commission Clerk Florene Davidson at least 10 days prior to the October 15, 2020 meeting.

That concludes Case No. 20779.

(Time noted 4:41 p.m.)

STATE OF NEW MEXICO)

: SS

COUNTY OF TAOS)

REPORTER'S CERTIFICATE

I, MARY THERESE MACFARLANE, New Mexico Reporter CCR No. 122, DO HEREBY CERTIFY that on Thursday, September 3, 2020, the proceedings in the above-captioned matter were taken before me; that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability and control.

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

/s/ Mary Macfarlane

Mary Therese Macfarlane, CCR
NM Certified Court Reporter No. 122
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