STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

CASE NO: 20708

APPLICATION OF SALT CREEK MIDSTREAM, LLC FOR AUTHORIZATION TO DRILL, COMPLETE AND OPERATE AN ACID GAS INJECTION WELL AT THE AMEREDEV SOUTH GAS PROCESSING FACILITY IN LEA COUNTY, NEW MEXICO.

REPORTER'S TRANSCRIPT OF PROCEEDINGS
COMMISSIONER HEARING
Agenda Item 5
December 11, 2019
Santa Fe, New Mexico

BEFORE: ADRIENNE SANDOVAL, CHAIRWOMAN
NIRANJAN KHALSA, COMMISSIONER
DR. THOMAS ENGLER, COMMISSIONER
MIGUEL LOZANO, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Wednesday, December 11, 2019, at the New Mexico Energy, Minerals, and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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WITNESSES

EXHIBITS

MR. HNASKO: Thank you, Madam Chair, Commissioners. Good morning. My name is Tom Hnasko, together with Dana Hardy, we represent Salt Creek Midstream, the applicant for a permit to advance that is acid gas to Delaware Mountain Group the sequestration of acid gas.

MR. LOZANO: Mr. Hnasko, I apologize, I don't want to interrupt you, we have a few preliminary matters that the Director will address before we take your opening statement. I apologize.

MR. HNASKO: I apologize. Thank you so much.

CHAIRWOMAN SANDOVAL: This is hearing Case Number 20780 to consider the application submitted by Salt Creek Midstream LLC for authorization to inject treated acid gas into the proposed well located at the Ameredev South Gas Processing Facility.

The State Land Office has entered its appearance in opposition of this application. The Oil Conservation through timely notice has intervened for purposes of this hearing.

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

MR. HNASKO: Good morning, Commissioners, Madam Chair, Tom Hnasko and Dana Hardy on behalf of the applicant Salt Creek Midstream.

MR. AMES: Good morning, Madam Chair. Eric Ames, general counsel, Energy, Minerals and Natural Resources Department, here on behalf of the Oil Conservation Division.

MS. ANTILLON: Good morning, Madam Chair, Andrea Antillon on behalf of the State Land Office.

CHAIRWOMAN SANDOVAL: Thank you.

This hearing will be conducted in accordance with the Commission's adjudication rules and in a fair and impartial manner to ensure that the relevant facts are fully elicited and to provide a reasonable opportunity for all interested parties to be heard.

The hearing shall proceed as follows:

One, all testimony will be taken under oath;

Two, I will admit any relevant evidence unless I determine that the evidence is unduly repetitious otherwise unreliable or of little value;

Three, any party who wishes to make a brief opening statement before presentation of direct testimony may do so;

Four, the applicant will present direct testimony first;

Five, other interested or intervening parties who have standing and who filed a timely prehearing statement or notice of intent to present testimony may present direct testimony;

Six, 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 the Commission will be conducted at the conclusion of each presentation, followed by cross-examination by any other participating party;

Seven, redirect examination will be permitted, but such testimony is limited to testimony relevant that was offered during cross-examination;

Eight, if time permits, and at my sole discretion, a party who wishes to give rebuttal testimony or make a brief closing argument may do so at the conclusion of the testimony in the same order as the direct testimony;

Nine, any objection concerning the conduct of today's hearing may be stated orally during the hearing with the party raising the objection briefly stating the grounds for the injection. The ruling I make on any objection and the reasons for it 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?

MR. HNASKO: No.

MR. AMES: No.

CHAIRWOMAN SANDOVAL: The applicant may now make a brief opening statement.

MR. HNASKO: Thank you, Madam Chair and

Commissioners. I apologize for the precipitous opening, statement, but --

CHAIRWOMAN SANDOVAL: You were excited.

MR. HNASKO: I'm so excited about the efficacy of our current application I couldn't hold back.

Madam Chair, Commissioners, as I mentioned, this is an application to advance an AGI well to the Delaware Mountain Group formation.

And in response, as the Chair noted, there was an initial entry of objection by the State Land Office and by the staff of the OCD to this, and we have, since those objections have been filed, we have gotten together and resolved the concerns of both intervenors such that they no longer oppose the application.

And I would like to briefly discuss what we resolved, and then we will elucidate that in our testimony this morning.

First of all, there is a preference by the OCD to drill these wells in advance to the Devonian formation. We have agreed to do so through an application for a Devonian well within six months after the Delaware Mountain well is approved.

It will be a redundant well, but at such time as the Devonian well is drilled and equipped and completed, we will switch disposal activities to that well as the primary disposal source, and as a result we will use the Delaware Mountain Group well, assuming it's permitted by this Commission, as a redundant well at that time.

And as a result of ultimately transforming the Devonian redundant well to the primary well, we will have minimal treated acid gas in the Delaware Mountain Group well. It will only last for a short period of time.

After having said that, even though the issues today are somewhat mooted by the agreement of the parties to ultimately complete that Devonian well, obviously it's extremely important that we establish we are competent to do so that the Delaware Mountain Group well in this particular location is not only appropriate, but is actually ideal for the treatment and disposal of TAG.

We are going to establish today through our evidence, our presentations, that the proposed location of this Delaware Mountain Group well has a perfect geologic seal, a good geologic seal of caprock to contain this TAG. It's isolated from the Capitan Reef, so we believe there is virtually no chance of infiltration to that reef.

The is no potential effect to oil and gas operations in the area, so correlative rights will be protected. From a geologic standpoint, it has good porosity and very good permeability in this area. What that does from our perspective is achieve the goals that everyone has, and that's to maintain a very small plume of TAG within the reservoir.

We believe the porosity of this particular location, as well as the permeability fully support the disposal activities over a 30-year period. Our calculations over a 30-year period show that the plume itself would extend only 0.15 miles in radius from the disposal location, which is a very small plume. Nonetheless, these concerns, as I mentioned at the outset, are largely mooted by our agreement to proceed with the Devonian well and ultimately transform our operations to that area.

So today, Commissioners, what we are going to establish and show, we are going to have three witnesses; Mr. Brian Perilloux, he is a professional engineer with Salt Creek Midstream. Mr. Perilloux has extensive experience in handling, management and treatment of TAG. He did so with Williams prior to his position here at Salt Creek Midstream, and he will tell you about the company.

Salt Creek Midstream is an interesting company because it's fully committed -- it's an equity-based company -- it's fully committed not only to New Mexico as a capital investment project, but it's committed to safety and environmental protection.

Salt Creek Midstream has internal policies that go above and beyond OSHA requirements and other requirements imposed for safety.

And of course you know Mr. Gutierrez. He has been here many times. He is going to describe the relevant hydrology and geology that I briefly summarized for you. He is going to show you about the injection zone, and why it is an ideal location for the deposit of this TAG, and why it's fully protective of the Capitan Reef, all fresh water supplies. It does not have the potential to impair upon correlative rights by interfering with any oil and gas production.

Mr. Gutierrez will talk about all aspects of the C-108 application and primarily explain the permit conditions that we have agreed to with the State Land Office and the OCD to proceed with the Devonian well application and to transfer operations to that particular well. It will be a little clumsy, but it won't be -- I think we can handle it.

Mr. David White will interrupt Mr. Gutierrez's testimony in a sense because he is going to talk about the seismic analysis he performed. He's an expert in that area, in the fault slip probability modeling.

And after Mr. White discusses the seismic analysis, Mr. Gutierrez will come back on the stand and talk about the design characteristics of the well itself and show that it's going to meet and exceed all standards for best available practices in constructing this well.

And primarily all of the geologic features that Mr. Gutierrez has determined in the C-108 application will be verified and unverified by the drilling program itself because we'll have core analyses to show the conditions of the formations, the conditions of the -- of the injection zone that we encounter, and of course whether any oil and gas is present in the area, which there is not.

So with that, Commissioners, we would begin with our case to present Mr. Perilloux to discuss the organizational structure of Salt Creek Midstream and his background in handling TAG and other related features of that disposal.

CHAIRWOMAN SANDOVAL: So I think before we do that, we want to go ahead and allow the Division and the Land Office to make an opening statement if they choose to do so. The State Land Office may make an opening statement if you chose to do so, or may do so at the beginning of your presentation of evidence.

MS. ANTILLON: The State Land Office will make an opening statement now.

Thank you, Madam and Commissioners. As has been noted today, the State Land Office initially did oppose this application by Salt Creek and through our concerns with injection into the Delaware Mountain Group, protection of the Capitan Reef, and also concerns with the proximity of that proposed well to state trust land.

The parties here today were able to reach a settlement in this matter which addresses the concerns of the State Land Office. That settlement included payment by Salt Creek for use of the state trust land space and additional permit for additions that the applicant will be speaking of today.

So due to that settlement agreement, the State Land Office now supports Salt Creek's application subject to the parties' agreed-to special conditions.

CHAIRWOMAN SANDOVAL: Thank you. The Division may make an opening statement if you choose to do so, or may do so at the beginning of presentation of evidence.

MR. AMES: Thank you, Madam Chair. The Division declines the opportunity to make an opening statement. We endorse what the State Land Office said about the resolution of the matter. OCD does not oppose the application, and we do not support it, but we do not oppose it either, and we will rely on our testimony to present our case. Thank you.

CHAIRWOMAN SANDOVAL: Thank you.

The applicant may now present direct testimony regarding the application. Will those persons that wish to testify at this hearing on behalf of the applicant please come forward so the court reporter can administer the oath.

(Oath administered.)

CHAIRWOMAN SANDOVAL: Thank you. Please call your first witness.

MR. HNASKO: Thank you, Madam Chair. The first witness of the applicant Salt Creek is Mr. Brian Perilloux.

BRIAN L. PERILLOUX

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MS. HARDY:

Q. Good morning, Mr. Perilloux.

A. Good morning.

Q. Please state your full name for the record.

A. Brian L., middle initial, Perilloux.

Q. Where do you reside?

A. Katy, Texas.

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

A. I'm employed by ARM Energy and assigned to Salt Creek Midstream, which is a subsidiary owned by ARM Energy and ARES, a JV partner.

Q. What are your responsibilities in your position?

A. I am senior vice president over operations and engineering, and I oversee and manage the operations of the physical assets of Salt Creek Midstream.

Q. Are you familiar with the information contained in Salt Creek Midstream's application for injection

authority?

A. Yes.

Q. Have you ever testified in an administrative hearing?

A. No.

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

A. Yes. I have a bachelor of science degree in mechanical engineering. I'm a registered professional engineer in the state of Louisiana. I have approximately 34 years of oil and gas industry experience, beginning my career with an engineering consulting firm principally focused on the offshore and onshore oil and gas production facilities.

I was at one point seconded to Exxon Mobile, known as Exxon at that time, for approximately three years to provide engineering and project management services for their sour gas treating facilities located in Alabama and Florida, along with their gas plant facilities located in Louisiana, Alabama and Florida.

Subsequently or about that time I became co-owner of an engineering consulting firm, again providing services to the oil and gas industry in various types of facilities, including sour gas treating facilities. That company existed for 14 years and was sold, at which time I took a position at Williams companies, which is one of the larger publicly traded companies in Midstream space.

I held various positions at Williams for approximately nine years, including director of E&C, engineering and construction, vice president of Midstream in the Gulf Region, and senior vice president of operational excellence.

The latter role included a group of about 800 people in the organization, and I was responsible for regulatory compliance, high level engineering, safety, and other aspects of mechanical integrity for all of Williams' assets.

In summary, I think I'm very well versed in most aspects of oil and gas production, processing and transportation, and I consider myself to be an expert accordingly.

MS. HARDY: Madam Chair, I tender Mr. Perilloux as an expert in petroleum engineering.

CHAIRWOMAN SANDOVAL: Okay. Do the members have any questions for the expert?

COMMISSIONER ENGLER: Quick question. What school did you get your bachelor's in?

THE WITNESS: Actually, the University of New Orleans.

COMMISSIONER ENGLER: New Orleans, okay, thank you.

CHAIRWOMAN SANDOVAL: Any other questions?

(No response.)

CHAIRWOMAN SANDOVAL: All right. The Commission will recognize this individual as an expert.

MS. HARDY: Thank you.

BY MS. HARDY:

Q. Mr. Perilloux, can you please identify the document that's before you and is identified as Salt Creek Exhibit Number 1?

A. Yes.

Q. What is that document, please?

A. That is an application for an AGI well in the State of New Mexico.

Q. Is Exhibit 1 a PowerPoint presentation?

A. Sorry, my mistake. Yes, this is the presentation, the application to inject and C-108 application.

Q. Is the PowerPoint presentation marked as Exhibit 1?

A. Yes, it is.

Q. Who prepared the PowerPoint presentation?

A. Salt Creek Midstream and Mr. Gutierrez prepared the presentation.

Q. Are you familiar with the content of the

presentation?

A. Yes, I am.

Q. And Mr. Gutierrez will be testifying; correct?

A. That is correct, yes.

Q. Who prepared Salt Creek's application for injection authority?

A. Geolex Company.

Q. Why did Salt Creek select Geolex to prepare the application?

A. Well, we sought to select a company that had the expertise that we thought was premiere, and knowledge of the State of New Mexico, and, in particular, AGI wells in the State of New Mexico, so we picked what we believed to be the best company to handle the application.

Q. Did Geolex perform its work at Salt Creek's direction?

A. Yes.

Q. Did you delegate to Geolex the responsibility for providing notice of the filing of the application and the Commission hearing?

A. Yes.

Q. Let's talk about the slide that's up now which is the organizational structure of Salt Creek. When was Salt Creek founded?

A. Salt Creek was founded in 2017.

Q. How many individuals does Salt Creek employ?

A. Salt Creek proper has approximately 86 employees who are assigned from ARM Energy, the parent company, which is approximately 200 employees.

Q. Okay. Is Salt Creek committed to working cooperatively with producers in the area?

A. Yes.

Q. Can you please generally describe Salt Creek's organizational structure?

A. Sure. So on this particular slide, I mentioned ARM Energy is the parent company. ARM Energy has existed since 2004 in the space of marketing and trading, working with multiple producers in the industry, and it's built a reputation of -- in the -- in the energy industry. In 2017 ARM Energy formed a JV with ARES equity backer to form Salt Creek Midstream to build assets in Texas and New Mexico.

Q. Look at the next slide which discusses the treatment and disposal of sour oil and gas. What is sour oil and gas and how is it treated?

A. So sour oil and gas, by definition, is natural gas that contains one of three contaminants, hydrogen sulfide or H_2S; mercaptans, which are sulfer-based compounds; and/or carbon dioxide. It's very common to see H_2S and carbon dioxide together which is traditionally called acid gas.

And the acid gas or these contaminants, if you will, in the natural gas are considered to be contaminants that in order to make the natural gas marketable, you have to remove those contaminants and dispose of them.

Q. Let's go to the next slide. Can you please describe the method that can be used to dispose of the H2S?

A. Sure. So when I think of disposing of H2S, first off, H2S is naturally occurring in, in nature. In fact, even the human body produces small, small amounts of H2S and it is, at higher concentrations, a toxic gas, and it is very lethal.

The negative quality of H2S is it doesn't take a very large amount, relatively speaking, to be lethal. Traditionally speaking, on the order of 500 to 1000 parts per million is a lethal, potentially lethal dose to humans.

In the wells in New Mexico, in this particular area, particularly Lea County, often the produced gas coming from production wells will have anywhere from 10 to 20 or more thousand parts per million. So it's a very con -- very concentrated in the natural gas.

So to treat the natural gas to remove the sour components, there is what I think the foremost prevalent methods starting with an amine system. Amine is an aqueous solution, so it's a water-based solution that chemically combines with the H2S and carbon dioxide to strip it out of the natural gas, thereby purifying the natural gas.

And once removed in the amine solution, by heating the amine solution, as a chemical reaction it reverses the reaction, releases the H2S and the CO2 as acid gas, commonly known as TAG, total acid gas, and that total acid gas is then disposed of.

In my option one we would dispose of that acid gas in an AGI well. I think the benefits of that particular solution is it's a tried and true method of disposal. The chemical is regenerated and reused. It only has to be replenished over time in small concentrations due to incidental losses which ultimately go down the disposal well.

The only real negativity of that is the acid gas well has to be located reasonably close in proximity to the treating facility, and depending on the formation -- and Mr. Gutierrez will testify to -- we have to select the ideal location for the well, for the acid gas disposal well, which may or may not be in close proximity to the production field of the oil and gas. So that's the down side of the AGI well is you can't just put one anywhere, and you can't pick it up and move it to another location.

One added benefit of the first method is sequestration of carbon dioxide which also would be injected into the disposal well thereby not an emission as a greenhouse gas emission.

The second method, also amine treater on the front end, but on the back end the TAG gas would actually be converted elemental sulfur through what's called a Claus plant. That's another well recognized and readily used -- utilized method of converting H2S to elemental sulfur. It normally comes out as a liquid sulfur on the back end of a Claus plant and is trucked or railed out of the facility either to a landfill for disposal or can be commercialized and sold to fertilizer industries and other such uses.

Currently the market for sulfur is, is not very favorable to disposal, so anyone with a Claus plant today would most likely be sending sulfur to a landfill. The downside, whether it's being commercialized or sent to a landfill, with liquid sulfur is the numerous trucks trucking liquid sulfur on the highways from the Claus plant to the disposal or market sites.

Secondly, in this particular method, the Claus plant does not sequester the CO2. The CO2 is naturally vented to atmosphere usually through a thermal oxidizer, combust incidental BOCs.

The third method that's commonly used in the industry is chemical scavengers or iron sponge. Iron sponge is, think of it basically as steel wool in a vessel. It basically captures the H2S and converts it to essentially rust and iron sulfide. Iron sulfide is not necessarily toxic, but it is pyrophoric, meaning it will auto ignite and burn.

So iron sulfide, also as you dispose, and this particular method is not regenerative, so you dispose of your iron sponge as it's consumed and replace it with new iron sponge. The disposal product goes to a landfill, which has a risk of pyrophoric ignition and fires in landfill and that sort of thing, so it has to be disposed of accordingly.

The chemical scavengers in this category are commonly -- a common chemical is triazine, which is also an aqueous solution similar to amine, but is not able to be regenerated, so it is a consumed chemical and can, in this particular area of New Mexico with the high concentrations of H2S, it takes very large quantities of chemical on a daily basis.

Just to give you an idea, in the 10 to 20 million cubic feet per day range, you might consume 10,000 to 20,000 gallons of chemical on a daily basis which has to be trucked in and both out of the facility for disposal.

The spent chemical is normally injected into waste disposal wells which, again, is -- it requires trucking to those locations. The other negative here on this particular method, it does not sequester carbon dioxide, so carbon dioxide would have to be removed by other methods, typically an amine system, in which case you would then vent or dispose of the C02 into the atmosphere through a thermal oxidizer, again, a greenhouse gas emission.

Lastly, another process that is a fairly old and well-known process called redox or reduction oxidation, redox uses a chemical, essentially iron chelate, which you think of it as rusty water, that actually absorbs the H2S through an oxidation process, and you can reverse the process by aeration and large amounts of air bubbles through the solution causing the sulfur to fall out in a solid cake form.

That solid cake is then pressed and dried, put into bins, roll off bins that are put on the back of trucks, and it's trucked to landfills to dispose of the solid cake sulfur.

The particular down side of the redox process is it's limited in its capacity to treat. Typically the systems are 15 to 30 million cubic feet per day as a maximum. They also have limitations in terms of the amount of sulfur cake that you can pull out of the regeneration side of the process.

They have a tendency to have other emissions such as detoluene and benzene and other emissions that during the reverse process or regeneration of blowing air through it, that is emitted to the atmosphere, small quantities but it is possible.

It has a very high operating cost and capital cost, and again, with the limited volume of production it makes it mostly non-economical to use that as a solution. And lastly, it does not sequester CO_2, once again, which would have to be removed by another process such as amine and vented to the atmosphere.

Q. Would you tell me what other factors must be considered in the disposal of H_2S?

A. In my opinion, again, I mention that the treating facilities should be located in close proximity to the oil and gas production facilities. If they're not, then the sour gas, sour natural gas, some go out of the wells would have to be transported over some distance from the well production site to the treating facility.

The longer that distance, the more exposure the public would have. So ideally you want to put your treating facility in close proximity, and likewise, the acid gas injection well in close proximity to both the treating facility and the production wells as close as possible or practical.

Secondly, I think the TAG or acid gas should only be transported in very short distances, and I consider short up to one mile. And the reason is, obviously, the TAG gas is concentrated H_2S, and very high concentrations typically in this area 30 percent of the TAG stream or more could be H_2S, which is 300,000 parts per million. And 300,000 parts per million, if released to the atmosphere, would require a fairly large radius of exposure to be diluted down to something under 100 parts, which is about the limit that we consider human exposure.

So we would prefer to have the acid gas well very close to the amine treating facility just to limit the distance that you have to move the acid gas.

Q. In the four methodologies you discussed, is the AGI well the only one that allows for sequestration of CO_2?

A. Yes, that is correct.

Q. How is CO_2 handled if not sequestered?

A. As I previously mentioned, CO_2 is a contaminant to natural gas, and in quantities above approximately 2 percent in the natural gas, it becomes non-marketable.

The second point is, is natural gas goes to a gas treating -- I'm sorry -- a gas processing facility where natural gas liquids are extracted, that's the ethane, propane, butanes, et cetera, to render the methane principally as the natural gas that's distributed to the end users.

In that gas processing facility, it's generally done by cryogenics, and cryogenics will have a -- actually CO_2 into the inlet of a gas plant will cause freezing inside the plant or plugging, ice plugs of CO_2, so it has to be removed from the front end of the gas plant. Even if the natural gas only has 2 percent, most natural gas processing plants have an amine system to remove the CO_2 which is either vented to the atmosphere or vented through a thermal oxidizer to the atmosphere.

Q. Based on the information you have provided regarding the options for disposing of acid gas, what is your conclusion here?

A. My conclusion is the most environmentally friendly, commercially available, and economically feasible solution is an amine treating facility with an acid gas disposal well located at the site to dispose of the TAG.

Q. Look at the next slide which relates to the Current and Future H_2S Treating Investment. Can you please describe the H_2S treatment facilities?

A. Yes. So we are located in Lea County just north of the Texas-New Mexico border. And in the graphic, the diamond is identified as the AGI well location, which is the site of our existing amine treating facilities.

We also considered a Valkyrie unit, and that's a trade name for a redox system, about three to four miles north, which is also denoted here. We have since suspended the installation of that in favor of going forward with our AGI well.

We currently have at the AGI treating location, treating plant, a system that's capable of about 35 million cubic feet of gas treating. It has a 475 GPM amine circulation system, which is comparable to the 35 million cubic feet of gas, and we are capable of removing about 7 percent CO_2 and approximately 25,000 parts per million or 2.5 percent H_2S to the inlet gas stream.

Q. Does Salt Creek have a contingency plan?

A. Yes. We have a contingency plan filed, and we've updated that plan accordingly as we have made changes, and we will have an additional update once the AGI well is drilled and in service.

Q. Does Salt Creek plan to add additional treatment capacity?

A. Yes. We do look to the future, and based on producer activity in the area, we would expect to add up to an additional 50 million cubic feet of capacity, and that would be done in some time late 2020, perhaps the end of the third quarter.

Q. Have Salt Creek, New Mexico State Land Office, and OCD reached an agreement regarding permit conditions that require Salt Creek to drill a redundant medium well?

A. Yes.

Q. You have a document before you that's marked as Salt Creek Exhibit 2.

A. Yes.

Q. What is that document, please?

A. Sorry, would you repeat the question?

Q. Can you identify that document?

A. Yes. I can identify that document. It is the special conditions for Salt Creek Midstream, Case Number 20780.

Q. And is Exhibit 2 a true and correct copy of the permit conditions agreed upon by Salt Creek, the State Land Office and OCD?

A. Yes, it is.

Q. Will Mr. Gutierrez address these conditions in more detail in his testimony?

A. Yes, that is correct.

Q. Go to the next slide. Can you please describe Salt Creek's natural gas infrastructure.

A. Yes. I, I like to identify this graphic or map, if you envision a smiley face there, and kind of at the chin of the smiley face, right in the middle is a diamond. That's the location of our Pecos Natural Gas processing plant, and I like to use it as a central point because it's easy for me to describe the graphic from that point.

From that diamond, if you move to the right, we have a 30-inch natural gas gathering trunk line that extends up to the right and gradually curves up northward towards

New Mexico. As it crosses the Pecos River, it reduces to a 16-inch natural gas gathering line which extends all the way up into New Mexico to our gas treating facility located in Lea County.

MR. LOZANO: Mr. Perilloux, I don't mean to interrupt you. Could you point to that? I think it would be helpful to know exactly where you are looking.

A. Okay. I'm referring to this as the smiley face, and right in the center here is the diamond that's located just out of Pecos, Texas, known as our Pecos Gas treating -- I'm sorry -- gas production facility or gas processing facility.

So this line extending to the east is a 30-inch gas line that crosses the Pecos River here, reduces to a 16-inch that extends all the way up into New Mexico past our gas treating facility in New Mexico and about another three miles -- three to four miles north.

From the west side we have a 30-inch gas trunk line or gathering line that extends through the west up to a location here that we affectionately call the junction.

From the junction it reduces to a 20-inch gas gathering line, extending up into Eddy County into New Mexico. That 20-inch extends northward almost to Carlsbad or southeast of Carlsbad.

From the junction we have a 16-inch gas gathering line extending due west, and an extension northward up to south of the New Mexico border, and I will come back to this side in just a moment.

Just for incidental, we have another gas, small eight-inch line extending southward here, and a couple of laterals located off the main trunk lines.

Overlaid with this we also do crude oil gathering. We have a crude oil line which is a green line, I will start off from this case in New Mexico in Lea County. This line is not fully constructed this far north, but we are up, I believe, to a point right about here.

This crude oil gathering line extends down to a terminal. This is the location of our Wink Terminal in Winkler County, Texas. The crude oil gathering system has a south gathering line that extends down to another terminal called the Liberty Terminal which is currently under construction, not yet in service.

On the west side, the green over here once again represents crude oil gathering lines. We have a, a tank that's currently being commissioned in Texas called the Oila Terminal with gathering lines extending over to the junction and up into the -- I'm sorry -- to the junction, also gathering up into the New Mexico -- it's underneath the red line, so you can't see it -- over to the west to this location and extending up into -- this is not built yet or constructed yet, but built up into New Mexico, and this site would be the intention.

We recognize there is some challenges along this area with karst, so -- or caves, and so we may abandon this extension of the crude oil line on this side, but that's another matter.

So in essence, this represents -- map represents the infrastructure that we have put in place. It represents more than a billion dollars of investment, all constructed within approximately the last year and a half.

MR. LOZANO: Thank you, sir.

BY MS. HARDY:

Q. Look at the next slide, natural gas infrastructure. Can you explain what's on this slide generally?

A. Yes. So this infrastructure really looks at the Pecos Processing Plant, and so the graphic is the plant layout. It's approximately 325 acres, I believe, if my memory serves me correctly. We have actually two trains, so two 200 million cubic feet per day gas processing plants located in service at that site.

From that gas plant, as I mentioned on the previous slide, we have gas gathering. So we have 325 miles of gas, high pressure gas pipeline that range from eight inch to 30 inch with approximately a billion cubic feet of gathering capacity.

At that particular site at the Pecos location we have the ability to install up to three more gas processing increase the total capacity to a billion cubic feet or more.

We have approximately 5,000 barrels per day of condensate stabilization equipment in that location, so retrograde condensate that comes in in the natural gas gathering lines we can process and actually sell stabilized condensate from the facility.

We have slug catching capacity, approximately 40,000 horsepower of compression, much of which is installed at that facility, but we also have field compression stations that gather low pressure gas from producers, put it into the high pressure gas line and move it to the plant.

On the residue system, we are connected to El Paso and ONEOK Roadrunner pipeline in Texas. We have NGL transportation capacity leaving the plant over to Waha up to about 450,000 barrels per day of NGL capacity. Part of that NGL capacity is in a JV with Apache, now known as Altos Midstream Company, where we move NGL from the Apache or Altos plant as well.

And on the NGL side we have interconnects with EPIC and Enterprise via the line to the Waha system.

Q. How will the treated acid gas be transported to the AGI well that Salt Creek wants to drill here?

A. We will move the total acid gas or TAG from the treating facility to the well which will be in very close proximity to a pipe. And personally I like to clarify that that pipe is, is not necessarily a pipeline. I personally -- this is my definition. I'm not sure if it's generally accepted, but I think of a pipeline as connecting two separate facilities, so -- as opposed to a pipe which is on the same facility.

And so in this particular case, the AGI well will be located on the same site or facility -- or at the same facility as the acid gas -- I'm sorry -- the sour gas treating equipment, so the amine treating system is located on the same site.

It's a matter of hundreds of feet, not miles, between the amine treater and the acid gas well proper. In contrast, if the AGI well were not at this particular site, but located remotely, you would have an acid gas pipeline extending from the treating facility to the AGI well location. So I just wanted to make sure I clarified, when I say a pipe, it means it's on the same facility.

Q. Will the pipe be designed and constructed in accordance with standard industry practices?

A. Yes, that is correct.

Q. Go to the next slide, please, Operational Excellence. Can you please describe Salt Creek's approach

to protecting health, safety and the environment?

A. Yes. There's quite a few words on this slide, but I like to start with kind of the foundation of what I think Salt Creek calls near and dear. And that is, there is two things in the industry we hear, and one that you typically hear first is, is someone will say safety.

We think safety is paramount and most important, but I also like to couple that with another word, and that's integrity. In my opinion you need both of those in equal proportion. In fact, I might argue that integrity should be first and safety is second, and the reason is that your safety program doesn't matter if you don't have integrity to support it. And so those two words to me underscore what we principally believe in.

You know, handling sour gas, acid gas, is -- is something that has a lot of risk associated with it. And if I could borrow the words of a former Blue Angel pilot named John Foley, I once saw a presentation by John Foley and someone asked him if what he did was dangerous, meaning Blue Angel formations, planes flying at 600 miles an hour, 36 inches apart, wing tip to wing tip, and his answer I thought was pretty good.

His answer was, "What we do is not dangerous, it's just unforgiving." And I like to use that with my operations team because I think of that exactly the same way. Maybe another analogy is, I think of operating sour gas treating facilities and handling of sour gas and acid gas is a path walking along the edge of a cliff, or imagine walking along the edge of the Grand Canyon. My job and our company's job is to provide enough guardrails to make that a safe operation. In the absence of those guardrails, you are depending on luck, and I don't believe luck is a strategy.

Coming from a leadership position in Williams, which again I mentioned is one of the larger publicly traded Midstream companies, I brought a lot of the learnings from Williams in my 34 years of experience in the industry.

I have been at locations where they have had releases of sour gas. I personally was involved in a sour gas release at a plant in Alabama once. At 2 o'clock in the morning the release was happening in the plant. I had to put on an emergency air pack like the firemen wear, the Scott air pack at 2 o'clock in the morning to evacuate the facility. It was either that or I would not be here today.

So I treat sour gas and sour gas production very seriously, and I treat it as being very unforgiving. It can be very safe in the operation as long as we establish the guardrails that are necessary to prevent a loss of containment.

Part of the strategy of preventing loss of containment is having a very competent person leading the compliance, both regulatory compliance area and the mechanical integrity area, which we do have currently in our company. And that integrity program, coupled with the programs to meet all regulations and industry standards provides those guardrails along the path to prevent us from slipping over the edge.

Q. Mr. Perilloux, can you please look at the document before you that's marked as Exhibit 3?

A. Yes.

Q. Can you please identify that document for the record?

A. Yes. That is the First Amendment of the Term Right-Of-Way Agreement between Beckham Ranch and Salt Creek Midstream.

Q. Are you familiar with the terms of that agreement?

A. Yes, I am.

Q. Is Exhibit 3 a true and correct copy of the agreement?

A. Yes, it is.

Q. Does the agreement allow Salt Creek to install and operate an AGI well on the proposed site?

A. Yes, it does.

Q. Mr. Perilloux, will the ability to inject treated acid gas into the proposed well result in more efficient

operation of the plant?

A. Yes.

Q. In your opinion, will Salt Creek's proposed method of disposing of treated acid gas protect public health and environment?

A. Yes.

MS. HARDY: Madam Chair, I would move the admission of Exhibits Salt Creek 1 through 3.

CHAIRWOMAN SANDOVAL: Are there any objections from the Division or State Land Office to the entry?

MR. AMES: No objection.

MS. ANTILLON: No objection.

CHAIRWOMAN SANDOVAL: They can be entered into the record.

(Exhibits Salt Creek 1 through 3 admitted.)

MS. HARDY: I have no further questions of Mr. Perilloux.

THE WITNESS: Thank you.

CHAIRWOMAN SANDOVAL: Thank you. Does the Commission have questions or wish to cross-examine this witness?

COMMISSIONER ENGLER: I would like to question, Madam Chair.

Your facility, you said you have 35 million for capacity. Is it running at full capacity? How much are you running through there now, just like a general average.

THE WITNESS: Presently we are running approximately 6 million cubic feet of gas, and we have capacity with the triazine system that's currently being used to remove the H2S capacity to run up to about 12 to 18 million cubic feet of gas, but currently it's 6 million at the facility.

COMMISSIONER ENGLER: Was that 6 million, and you have -- I think you mentioned some -- a percentage or how much CO2 you're actually pulling out of that.

THE WITNESS: Yeah. So we are pulling out approximately 2.5 percent H2S. The CO2 is actually being flared at the facility.

COMMISSIONER ENGLER: And in your proposal, you want to up that capacity another 50 million?

THE WITNESS: That is correct.

COMMISSIONER ENGLER: And so I guess the expectation that, that Salt Creek sees is that you are going to have a massive increase in input that you are going to need to be able to treat?

THE WITNESS: That's correct.

COMMISSIONER ENGLER: And so I guess you expect your CO2 volume -- CO2 and H2S volumes going up even higher than what you are right now in terms of treating and/or --

THE WITNESS: Yeah, the percentages remain relatively stable.

COMMISSIONER ENGLER: The same?

THE WITNESS: But the volume increases as production increases. That is correct.

COMMISSIONER ENGLER: Okay. Thank you.

COMMISSIONER KHALSA: No questions.

CHAIRWOMAN SANDOVAL: So you referred to your gathering system. What does that look like, at least on the New Mexico side in terms of a -- you mentioned you have a compression station.

THE WITNESS: Yes. Currently the compressors in New Mexico are located at the treating facility in Lea County.

CHAIRWOMAN SANDOVAL: Okay.

THE WITNESS: And we have two compressors currently installed to provide approximately 18 million cubic feet of inlet gas compression into the treater.

CHAIRWOMAN SANDOVAL: So most of your gathering system is on the Texas side?

THE WITNESS: That is correct.

CHAIRWOMAN SANDOVAL: Okay. But you do have a contingency plan in place with the Division for all of the assets in New Mexico?

THE WITNESS: That is correct.

CHAIRWOMAN SANDOVAL: Would you guys have a GIS map of that gathering system?

THE WITNESS: Yes, we do.

CHAIRWOMAN SANDOVAL: Is that something you would be willing to share with the Division as part of this process?

THE WITNESS: Yes.

MR. LOZANO: Madam Chair, if you don't mind, I have one question. Mr. Perilloux, I understand the agreement is to build the Devonian well within 15 months of this well issuance or permit issuance.

THE WITNESS: Correct.

MR. LOZANO: Do you have any of the same concerns with regard to location of that well? You mentioned, you know, transporting, things like that are an issue. Currently it will be on the same facility --

THE WITNESS: Yes.

MR. LOZANO: -- with the Devonian well. Will that also be or will you have it in a different location.

THE WITNESS: It would be approximately -- it would be on the same surface site within a couple hundred feet --

MR. LOZANO: Okay.

THE WITNESS: -- of the facility like the, like the Delaware.

MR. LOZANO: Okay. That's all I have.

CHAIRWOMAN SANDOVAL: Okay.
Are there any other questions from the Commission?
(No response.)
CHAIRWOMAN SANDOVAL: Okay. Does the State Land Office wish to cross-examine?
MS. ANTILLON: No questions from the State Land Office.
CHAIRWOMAN SANDOVAL: Does the Division wish to cross-examine?
MR. AMES: No, Madam Chair. Thank you.
CHAIRWOMAN SANDOVAL: Is there any redirect of the witness from the applicant?
MS. HARDY: No, Madam Chair.
CHAIRWOMAN SANDOVAL: Does the applicant have any additional witnesses?
MR. HNASKO: Yes, Madam Chair, we do.
CHAIRWOMAN SANDOVAL: Okay.
MR. HNASKO: Our next witness for Salt Creek, Madam Chair, will be Alberto Gutierrez.
May I proceed, Madam Chair?
CHAIRWOMAN SANDOVAL: Yes.

ALBERTO A. GUTIERREZ

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. HNASKO:

Q. State your name for the record, please.

A. Alberto A. Gutierrez.

Q. Where do you live, Mr. Gutierrez?

A. I live in Albuquerque.

Q. What's the name of your company?

A. Geolex Incorporated.

Q. What does Geolex Incorporated do?

A. Geolex Incorporated specializes in the permitting, construction, operation and analysis of acid gas injection wells, and we also do a significant amount of work in the investigation and remediation of contaminated groundwater and soil.

Q. And what's your job at Geolex?

A. I'm the president.

Q. I put up Slide Number 2, and this is a brief summary of your education and experience. Could you describe your education and experience, please?

A. Yes. I am a geologist. I have bachelor's degree from the University of Maryland in 1977, and a master's from the University of New Mexico in 1980. My -- I have had experience since about 1975 in the environmental area, and since the early '80s in the oil and gas area. And for the last 20 years we have been very active in the acid gas injection arena and have developed a national and international reputation in that area.

Q. And did you prepare Salt Creek's C-108 application?

A. My -- I did, and my staff under my direction, yes.

Q. And which members of your staff participated in that preparation?

A. There are a number of people that participated, but primarily David White and Jim Hunter.

Q. All right. I take it, Mr. Gutierrez, based on your experience you have prepared a number of applications for acid gas injection wells?

A. Yes, I have.

Q. How many?

A. At least a couple dozen in New Mexico.

Q. And --

A. And others in Texas and other locations.

Q. With respect to the applications in New Mexico, I assume you have testified at each of those hearings?

A. I have.

Q. All right. And you were recognized as an expert petroleum geologist and hydrogeologist in those areas?

A. Yes, sir.

MR. HNASKO: Madam Commissioner, based on Mr. Gutierrez' past acceptance as an expert in proceedings, I tender him as an expert in petroleum geology and hydrogeology.

CHAIRWOMAN SANDOVAL: Do any of the Commissioners have any questions for the witness?

COMMISSIONER ENGLER: No.

CHAIRWOMAN SANDOVAL: The Commission will recognize Mr. Gutierrez as an expert.

BY MR. HNASKO:

Q. Mr. Gutierrez, could you please identify Exhibit Number 4?

A. Certainly. Exhibit Number 4, which is in the -- right behind Tab 4 in your bound booklet is a copy of our original C-108 application submitted for this well.

Q. And I take it that's the same application that you testified you and your staff prepared?

A. That is correct.

Q. And that's a true and correct copy of the application you submitted in this proceeding?

A. I haven't gone through detail each exact page, but it is. I provided it to you.

Q. You have no reason to believe it is not; is that correct?

A. That is correct.

Q. All right. Mr. Gutierrez, I placed Slide 15 up on the screen for us to review, and this briefly summarizes the key elements of the C-108. Could you go through those, please?

A. Sure. First of all, the C-108 has all of the required information that is necessary to evaluate and hopefully approve this acid gas injection well proposal. I just want to point out some of the key elements of the project.

Some of these are not unique to this project because they are part of the things that Mr. Perilloux, for example, testified to in terms of the benefits of acid gas injection.

However, the AGI project has substantial environmental benefits because it allows for the production of sour gas and results in the sequestration of the CO2 associated with that gas as opposed to liberating it, using other kinds of technology like an SRU unit.

It also the aids facility in meeting its air quality regulation because SRUs and the associated units and some of these other treatment units are more prone to upsets that require flaring. So it eliminates a lot of flaring. It also -- the well design -- the way I like to look at AGIs is that you really have two primary aspects of how to safely design an AGI well.

One is the actual design of the well itself, but -- and that's important in terms of the integrity of the well and making sure there is -- it minimizes any kind of potential for gas, treated acid gas to get out of the injection zone due to the well construction itself.

Equally important is the natural conditions of the geology in the area and the ability of the reservoir to accept the acid gas that is being disposed of in there, to do it in a way that's consistent with the existing formation water and not cause an issue, and also to have an adequate seal that will keep the acid gas in the intended injection zone.

So all the nearby oil and gas wells and water wells, whichever few there are, are protected by this combination of these factors.

Q. We will get into that in some detail, but can you continue with some of the key elements of the C-108?

A. As I mentioned, it's got all of the application -- it has all the details necessary to evaluate it. The adjacent producers and operators strongly support the project. The operators and owners, surface owners have received proper notice, and there has been no objections to the proposed AGI project from either operators or surface owners.

And, as Mr. Perilloux mentioned, the facility has a Rule 11, an approved Rule 11 plan which will be modified to incorporate the AGI and the AGI compression facilities and will be submitted to the OCD for their approval prior to the use of the well.

Q. All right. Let's discuss briefly the location background and the purpose of this particular well.

A. Right. Obviously the purpose of the well, as Mr. Perilloux alluded to is to provide a disposal facility for the total acid gas and treated acid gas that comes out of the amine unit at that facility. It is located in Section 21 of 26 South and 36 East in Lea County.

You can see it on the map shown on the next slide. Right there. And it gives the location in terms of the coordinates for the well and its relationship to the facility. The well will allow the facility to dispose of the total acid gas generated from about ultimately 80 to 85 million cubic feet of inlet gas, as Mr. Perilloux described.

It will be a vertical well, and it's located approximately 600 feet from the west line, which is actually 5594 feet from the west line and 2379 feet from the south line, in that section.

Q. All right. And we've already discussed the location and the map you were citing to?

A. Yes.

Q. Slide 18.

A. This next slide is a picture of the facility. It looks kind of like a pretty open area because there is not a lot of the facility having been built at the time when this image was taken, but it also shows the location of the acid gas well and other wells in the immediate vicinity of the well.

Q. All right. Following up with that particular slide would you discuss in some more detail the plant site characteristics on Slide 20?

A. Sure. As Mr. Perilloux also mentioned, the facility is located on an easement that has been provided as Exhibit 3. The underlying mineral rights are owned by the US and administered by the BLM and by the State Land Office immediately adjacent to the -- on the section just to the west and to the south.

The field gas will be sweetened, as Mr. Perilloux aptly described. We don't need to go into all of that. And it will be all the surface equipment, including the well and compression facilities, if you show the next slide, you can see will all be located within the outlined area. The next slide is the map --

Q. Before we do that. Let's take a look at Exhibit 3, if you would, please, and identify that for us.

A. Yes, sir. Exhibit 3 is the First Amendment of the Right-of-Way Agreement between Salt Creek and Beckham Ranch, which was described earlier, and this agreement provides for the ability for Salt Creek to place an AGI on their land.

Q. Gives them the right to enter on the surface and do so?

A. That is correct.

Q. You mentioned Slide 21, which is the schematic of the plant. Could you explain that to the Commissioners?

A. Yes. It's just a general schematic of the processing plant showing the location of the existing process equipment, inlet compression and processing down in this area. The area for future expansion, as Mr. Perilloux described, are there. And this is the location of the flare, and that's the approximate location of the AGI well.

Q. Okay. Thank you. Let's move on here to some of the calculations of the injections and competition for the AGI well. Could you describe the proposed injection fluid volume?

A. Right. At full capacity, this facility would be generating approximately 8 million cubic feet a day of treated acid gas or total acid gas that would be comprised of approximately 22 percent H_2S, 78 percent CO_2, and some trace hydrocarbons which flow over.

The injected fluid compatibility was -- had been determined by 20 years of nearby injection experience and by looking at the types of brine that is currently in the proposed injection zone.

We calculated the MAOP which we are proposing of of 2149 psi based on the density of the acid gas and the -- and the depth of the well as per NMOCD guidelines.

Obviously we are going to do a step rate test when the well is completed, but we don't envision any need for raising that pressure at this point unless we encounter something we don't anticipate in the injection zone. We anticipate the actual injection pressure will be somewhere in the 1400 to 1600 psi range.

Q. Let's move on to the Reservoir Volume and Area Calculations. Could you explain how you went about performing calculations?

A. Sure. I'm going to summarize, they are summarized on this slide. The next slide gives details of those calculations, but basically under the anticipated reservoir conditions, we have to remember that, unlike water injection, when you inject treated acid gas, you are injecting a fluid is that compressible, in other words, atmospheric, temperature and pressure that is in a gas state and it occupies a certain volume.

Well, as you compress that to what we call a super critical state, the mixture of CO2 and H2S becomes a liquid, basically, and it is handled as a liquid. And when it enters the well, it enters as a liquid, but as a relatively lower density.

And then as it travels down the well itself, it becomes denser and denser and then when it enters the reservoir, based on existing reservoir pressure, it will remain in that compressed state in the reservoir. And what that means is that at full capacity, this facility would be injecting something under 20 -- 3270, 3268 barrels of acid gas a day into the reservoir.

The next table shows those calculations. This is included in the -- in the C-108 --

Q. Can we go back though to this --

A. Sure.

Q. -- for one moment. I just want to point out your fourth arrow, and you indicate after 30 years of operation the TAG will occupy a particular area.

A. Oh, yeah.

Q. Could you describe that, clearly given the agreement to go forward with the Devonian well as a redundant well and then transfer that well as a primary disposal option the 30 years of operation won't likely occur. But can you explain where you arrived at the conclusion that the TAG would occupy only an area of approximately 0.15 miles radius from the bottom of the well?

A. Basically when you inject acid gas into a formation, it displaces the existing reservoir fluid, typically a brine, in that formation, and it replaces it with essentially this treated acid gas liquid to fill that available floor space less the irreducible water, of course.

What we do is calculate volumetrically, and in this case, as Mr. White will describe in his testimony, we did a seismic analysis of the DMG, and we got some pretty massive sands that are good and permeable, and we saw that about from both the well logs and the seismic. And so therefore the porosity and permeability are such that even if you injected at full capacity, basically the 3300 barrels a day, roughly, of acid gas, it would only reach a radius of about 800 feet or .15 miles.

Q. Okay. Moving on to 24, we've got the maximum allowable operative pressure. Could you describe that determination?

A. Yes, certainly. The, the maximum injection pressure is taken into this formula which is shown in this area of the table that is OCD's standard formula for calculating the injection pressure maximum, MAOP, absent of a separate test.

And when we do that calculation we come up with about 2149 psi for MAOP. And you can see in the -- we've got conditions at the wellhead, and you can see the density of the TAG is only about .36 at the wellhead under these 110 and 1200 psi conditions.

But by the time you get to the bottom of the well, the pressure is 2976 pounds because of the depth and the hydrostatic head, and the TAG is now about .81 in density. So what we do is calculate the average density of that TAG over the well, and we put that into this equation. That's how we calculate our MAOP.

Also we, as you can see here at the reservoir, the space occupied by that TAG is significantly less than it is at the surface. At the surface when we first entered the well we are looking at about 7400 barrels a day, and by the time it's in the bottom it's about 3268.

Q. All right. That's due to compression of the TAG?

A. That is correct.

Q. Slide 25 you calculated the radius of the TAG plume after 30 years. Could you describe that, please?

A. Sure. This is just that 800 foot radius around the well. We really, in this case, given the seismic information as David will present, we feel pretty comfortable that this will be roughly a radial plume because the sands are fairly conducive to that kind of a plume.

Now what we are showing on here, there's a number of permitted wells. That's these blue squares. Those are typically horizontal wells that have been permitted that haven't yet been drilled. These green dots that you see are all oil wells that are completed in the area, but they are not necessarily wells that all penetrate the injection zone.

Some of them do, in terms of the vertical component of the well, but typically these horizontal wells go through our whole injection zone and then the zone they are producing out of several thousand feet below our injection well.

Q. As a result of that, what impact, if any, would the proposed AGI well have on these wells you described?

A. Well, based on the fact that all of them are largely outside or not -- largely, they are all outside of the maximum 30-year potential extent of the plume, we don't think it will have any impact on any of those wells.

Q. All right. Let's talk about notice to operators and surface owners. Did you provide notice of Salt Creek's application in this particular hearing?

A. We did.

Q. Go ahead and explain that.

A. We basically took, as has been the practice of this Commission for many years now, although for most C-108s the area of review is only half a mile, for AGIs we always use one mile.

So we notified every operator, every mineral owner, every surface owner within the one-mile radius of the proposed well, and in Appendix B of our application which is Exhibit 4, there is a sample notice letter like the ones that were sent to the individual notice, and also a sample public notice that then the Commission published for an announcement of the hearing.

We had not received any objections from any of the operators in the area, and we did receive an initial objection from the State Land Office and from the OCD which has been discussed before.

Q. All right. Your last arrow has some benefits of the project. Can you summarize those for the Commission?

A. Sure. It's going to allow, obviously, for the producers to increase their production and have some place to process the gas because without doing that, they can't produce the oil. The oil comes up -- the gas comes up entrained with the oil. It's not an either ordeal. So you have to do something with that gas. You can't flare it.

It will also increase royalties to the State of New Mexico from that additional production, and in fact from the payment that Salt Creek is making for the use of the floor space to the State Land Office, and it will also protect fresh land water resources and correlative rights.

Q. For purposes of the hearing today, Mr. Gutierrez, did you provide a sample of the notice letter?

A. I did.

Q. And that proposed exhibit, could you look at Exhibit 5 and identify that?

A. Exhibit 5 is a copy of the notice letter that was sent to Beckham Ranch, for example, and then copies of all the certified mail receipts and the subsequently received green cards, if you will, from the various individuals that were noticed.

In addition, there were a couple of notices that we got back because there was some changes in address or some changes in ownership, and we followed those up with some Federal Express notices to make sure they got to the right person.

Q. All of those receipts were returned as being delivered.

A. That is correct.

Q. And you mentioned I believe that notice was published by the Commission?

A. That is correct.

Q. Let's move on to the reservoir criteria which is the right here. Could you generally describe in summary form, there's detail, but what is depicted on Slide 27 with respect to reservoir characteristics?

A. Yeah. I think these are all things that I have already mentioned it, but it's one slide that says, okay, when I am looking for an AGI reservoir, what are the main things I look for? And this is what they are.

One, we need a geologic seal above and below to permanently contain the TAG. We need some isolation and fully protective from any fresh water resources, which is very easy to do in our state because unfortunately we don't have a lot of fresh ground water at depth in these areas.

We do have some potential water in the Capitan Reef, but that is not necessarily fresh ground water, but it also has been deemed to be protectable, and that is another issue that we have considered.

We also are looking for something that's not going to have an effect on existing or potential gas and oil production. And we are looking for laterally extensive, high porosity and high permeability reservoirs to allow that gas to be injected at reasonable pressures.

We are looking for excess capacity in that reservoir so that it will take what we want to give it and then some without significant pressure, and then we are looking for compatible chemistry in the --

Q. Do you have an opinion, Mr. Gutierrez, as to whether Salt Creek's application satisfies each of these criteria?

A. I believe that the location and the physical geology at the site and the well design satisfy all of these criteria.

Q. All right. And did you also take a look at offset oil and gas and injection wells in evaluating the proposed location?

A. We did. As required by the C-108 application process and the process that has evolved with this Commission over the past 12 or 15 years, we look at all of the wells, as I mentioned, within a one-mile radius. We also, of course, provide a C-108 that has the two-mile radius wells shown and list it.

But we also provide the one-mile radius, and this is the result of that analysis. There are 56 wells within a mile of the proposed AGI, 22 of which are active, 21 of which are plugged and abandoned.

Now it's very important to note that the majority of these wells never even reach the injection zone. They are completely above the injection zone in the caprock. They are very shallow producers.

Now, of the completed wells there are six that penetrated deeper than the top of the injection zone. Five are active and one is plugged, and most of those are producing wells that have a vertical section that penetrate that zone, but then a producing zone below it. And then also there are some saltwater disposal wells also in the Delaware Mountain Group within that one-mile area.

Q. Okay. The wells you mentioned that went deeper

than the proposed injection zone, those would be Bone Spring and Wolfcamp wells?

A. Yes.

Q. And on your last arrow, you have reached a conclusion as to how the injection zone and the proposed AGI location would affect, potentially affect any of the wells or correlative rights in that area, and what did you come up with?

A. We feel confident that the injection as proposed with a maximum volume of 8 million even if we were to continue to the operate the well for 30 years would not have any deleterious effect on the zone.

Q. Okay. Can you describe what's on Slide 29, please?

A. This slide is just a picture of what I just had described on the previous slide. You can see these are the existing and proposed wells. The proposed wells are shown in blue squares. The existing wells are shown in green, and the ones that are circled in red are the ones that actually penetrate the injection zone.

Q. All right. And what's the depth of those particular wells.

A. Well, I don't know off the top of my head exactly, I could look them up, but some of them were actual dry holes that were plugged that were deeper zones or plugged back, and some are plugged old wells, and then some are these new horizontal, vertical and horizontal.

Q. Okay. Let's discuss the stratigraphy of the proposed injection area on Slide 30 and can you describe to the Commission what you have here?

A. Sure. The proposed well is in -- if we could, if we could just switch forward to the next slide, I think that -- this is a good way to show it. The Permian Basin is comprised of several structural elements. The Midland Basin here, which is a relatively deeper portion of the basin, the Central Basin Platform, which we are off the edge of here in our proposed location which separates the Midland and the Delaware Basin, the two deeper portions of the -- of the Permian Basin.

And we have a -- this Diablo Platform which merges into the northwest and eastern shelf that defines the northern and western portions of the basin.

So basically the stratigraphy here is the typical -- if you switch back to the previous slide, yeah -- the injection zone is capped by about 1500 feet of tight shelf transitional facies carbonates and shales, as well as the Castile Formation anhydrite.

The Bell Canyon and Cherry Canyon are porous portions of the upper part of our injection zone in kind of a sweet spot where we are going to look for our injection.

And then, like I said, the next -- the next couple of figures, Number 6, which we just saw, and Number 7 which shows the stratigraphy, I can describe that in detail.

Q. Let's describe in some more detail what you call the sweet spot of the Bell Canyon and the Cherry Canyon formation, how is it that the porous sandstone in that area will be keeping the plume minimal?

A. Well, basically it's pretty simple. The, the more porous space you have in that rock, the less distance that the plume will migrate away from the well because it's basically filling up first the space nearest the well. So it's kind of like pouring water in a bucket, the bigger the bucket, the less amount of space that the water takes up.

In the stratigraphy, here this is a pretty good -- this is a well nearby that is an offset well that shows what the low permeability units that I was talking about that are above the -- the injection zone running from about where the Lamar Limestone is to the Castile, and you can see are very, very low porosity. We get much better porosity in the Bell Canyon, Cherry Canyon and the upper portions of the Delaware Mountain Group which is the area that we are selecting for an injection zone.

In the Delaware Basin in this area, you know, we have production in the Bone Spring and Wolfcamp that's below us here, and you've got a fair amount -- a significant amount of Brushy Canyon, very low porosity Brushy Canyon between our proposed injection zone and these producing zones in the Bone Spring and the Wolfcamp.

And then there are some older zones in some of the wells that I said were plugged. They tested the Devonian for production, and then they tested a variety of other zones including the Delaware Mountain for production and were not able to find any.

Q. So the low porosity zones you spoke about, those essentially form the cap?

A. They do.

Q. And make sure that the -- ensure that the plume doesn't migrate?

A. They do. And I want to add something that isn't -- that is not, I mentioned this in the discussions that we had with both the OCD and the State Land Office that we just recently completed less than a year ago a well in the Delaware Mountain Group in Texas. It's quite a ways from here, but it's on what we would call -- if you could go back to that slide -- on strike with this well.

So the formation that -- the Central Basin Platform, our other well is about down about here in Winkler County, Texas, and we saw a very, very similar kind of stratigraphy. And when we drilled that well, we actually have gotten much better performance that we even anticipated out of that well.

In other words, we anticipated the injection pressure for the amount of volume that we are putting away in that well, which is about 3 to 4 million, an injection pressure of somewhere around 16- or 1700, something like with what we said here, and actually we are seeing more like 1300, so it really is -- we believe it's an excellent reservoir.

Q. You anticipate similar results in this particular location?

A. We do. Although, you know, it's not -- it's never over until the fat lady sings. So we are going to do coring of that injection zone and the caprock. We are going to do very detailed FMI logging of those zones, and with that we should be able to correlate and to have a much better understanding of what we are looking at.

Q. Okay. All right.

A. Would you like to go on to Slide 33 and talk about the structure of the proposed injection area?

A. Again, being a geologist, I need a map to talk about it intelligently. The next one, there you go. So we can see the proposed AGI is located here in Section 21. This is a cross-section that's a very long cross-section, but it's because we are trying to capture all the wells that really penetrate that zone to get a better idea of what it looks like.

But what we got is from this northwest shelf, we have these progressions into the basin. These are a structure contour map showing the top of the Bell Canyon. So you can see it dips here. It's got a shallow trough here. It's got a small raised area in this location. And generally it's slightly dipping here, and it -- there are no significant structures or faults in this area.

We did look at the -- at the seismic in great detail, and David will talk about that. We did identify some things that we thought might be potential faults, and so we, in a conservative manner, treated those in that analysis that way. But there really isn't any significant evidence of faulting in this area.

Q. All right.

A. This is, by the way, the next map is an isopach map of the -- and you can see that during the time when this Bell Canyon and the Delaware Mountain Group was deposited, there were numerous essentially channels draining off of this higher area and which were filled with sand from the, the erosion off of this Central Basin platform area, and therefore you've got these thicker zones of the sands that you can see in here going to as much as a 1000 or 1100 feet thick in places.

We are not located -- ideally, you know, if we wanted to even maybe minimize the plume size further, we might have gone into one of these deeper zones, but unfortunately it probably wouldn't have made too much difference because the bottom of those zones, the Brushy Canyon is not very permeable, it won't take much, and a lot of the excess fill in this area is Brushy Canyon.

So you can see we are in an area where we've got about 800 to 900 feet of Delaware Mountain here in our location, and David will describe a little bit more about the detailed stratigraphy and structure or detailed structure.

Q. Let's talk about the anticipated porosity some more. You probably have to go to Slide 37, but Slide 36 is a summary of that. Could you describe that, please?

A. Sure. Basically what we see in the cross-section that was in the C-108, which is the next slide, is that these yellow zones are the zones that are indicated with higher porosity. Our current proposed well is here. We are grading to kind of a shelf facies above our injection zone here, and that's what provides this very low permeability, low porosity formation that is immediately above our injection zone.

And you can see the best porosity really is in the upper portion of the Delaware Mountain Group in the Bell Canyon, Cherry Canyon. And by the time you get down to this portion of the section, it's really pretty low porosity, and that's what provides these alternating seals for the basal portion.

Of course, even though the -- you know, there is this kind of concept that because the TAG that is in this reservoir is less dense than the fluid that is around it, that it tends to be buoyant in there. But what we have seen, really, is that while that has a tendency and it's very difficult for acid gas to travel down through that if it can travel up or out, as in most geologic environments, the vertical permeability is usually some fraction, more like a tenth of the horizontal permeability. So the main expansion is going to be in that zone up to that about 800-foot radius after 30 years.

Q. And the lower porosity top and bottom essentially form the bookends for the injection zone and ensure that they are contained within that zone?

A. That is correct.

Q. Let's go back to Slide 36. You talked about the investigation of subsurface structures. If you discuss your findings there.

A. Yes. As I mentioned from the well log information and stuff, we couldn't really see any significant indication of structures in the area. But when we took a look at the 3-D seismic, we did see two kind of

NNW-SSE trending faults that are approximately three miles east and northeast outside the area of review.

And I think those are discussed and will be discussed by David in his analysis, and they are included in our induced seismicity risk assessment. And these structures, though, pose no hazard to the project. And as you will see from David's analysis today, there is no indication of a probability of increased seismicity due to that injection.

Q. All right. I think you covered Slide 37.

A. I have.

Q. But notwithstanding your testimony on Slide 37, you're aware, of course, that the State Land Office and the OCD had some concerns with the application. Correct?

A. Yes.

Q. And you participated in discussions about those concerns in an attempt to resolve them?

A. Yes, sir, I did.

Q. Okay. Let's look at, before we talk about the resolution, let's talk about the concerns.

A. Sure.

Q. Slide 38, would you please summarize the concerns as expressed to you?

A. Yes. The concerns that were expressed to us by the State Land Office and ultimately echoed by the OCD was that there was a potential for nearby production in the proposed injection zone, that their presence of horizontal wells that penetrate that injection zone, there is potential for communication between the zone and the Capitan Reef.

There is an elevated health and safety risk to nearby producing well operators because they may have to drill through a zone that has treated acid gas in it, and then that the migration of the acid gas in the producing wells into the Delaware and deeper formations could occur.

Those were, in a very summarized fashion, the main concerns that were laid out to us.

Q. Is it your understanding, Mr. Gutierrez, that the concerns have been resolved through Exhibit 2?

A. That is correct.

Q. Let's talk about them anyway, if we can, how we addressed them, and your point-by-point rebuttal or response to the SLO and OCD concerns.

First of all, the concern about production in the area is potentially affected by the proposed AGI well and it's location.

A. There is two things that, that were, I think, of potential concern to the OCD and the State Land Office relative to this issue. One was whether or not there is unknown or potential production in the Delaware that we don't know about that could be negatively affected.

Well, what is the -- what is the data that we have to look at there? What we have is that, the closest thing we have is this well, which was tested back in the early '90s in the Delaware Mountain Group, and it basically burped a little bit of gas and oil for about a month, and then it was plugged because it was not commercially productive.

In addition, there are -- there are a number of saltwater wells that are kind of -- there are some production wells in this Delaware Mountain Group, but those are located basically a township away to the west, and there are saltwater wells, a number of them, between us and those in the Delaware Mountain Group.

So we felt from that, from that perspective, we really -- and again, remember, we are talking about 800 feet. I mean, that's probably smaller than the red dot that's shown on the map which is what 30 years of injection will do.

So you see it's very far removed from the nearest potential production in that zone and even farther removed from where it was tested here. And this was stratigraphically a much higher position. So if there was any oil and gas in the Delaware Mountain, it would be in this area, that's why they drilled the well there in the first place, but that didn't happen.

So that was one item. The next item is that -- and this ties into the concern about the adjacent producers being potentially exposed to this H2S while drilling through the zone.

Well, the main thing that's protecting us there is our proposed plume injection zone will only result in a plume after 30 years of only about 1600 feet in diameter and 800 feet in radius, and you can see it's away from the vertical portions of those wells except for this one on the edge. But again, that's kind of a moot point given what agreements have been reached.

But nonetheless, it's important to note this, very important, I think, because producers in this area routinely deal with H2S. In other words, the whole reason why we are doing this and why there is a processing plant there is because we produce sour oil and gas, so these guys have to be prepared.

Now, it's very different when you are looking at, you know, 20,000 parts versus 20 percent, clearly, but what we have found over the last 25 years of doing research in this area is that these plumes do not mix. They stay as a lens, if you will, of TAG within the injection zone with a very, very small reaction boundary.

And so that effect of the TAG is going to be very limited to the facility area and not cause any problems from that perspective either.

Q. All right.

A. So that took care of basically Item Number 1 and again Item Number 4 that we talked about, but there is also no horizontal wells that are currently penetrating the proposed injection area and plume except this one at the very edge of the 30-year plume. If we go to the next slide.

Q. All right.

A. The next concern was the Capitan Reef. Well the Capitan Reef really lies east of where we are, and the four shelf deposits are much, much lower porosity deposits that you see here in the -- above the Bell Canyon, and so we feel pretty comfortable that these are going to produce an excellent -- here is 500 feet of this material, a little higher porosity here, and then another 3- or 400 feet of very low porosity, very low and so we feel that these zones will protect the Capitan Reef because we are not really drilling through the Reef, we are in the four reef area.

Of course, again, as I mentioned, what's really going to determine where the well is is, what -- I mean, where it is relative to these features is the logging and coring that we will do before we even complete the well.

Q. All right.

A. This --

Q. You have shown this more on --

A. Yeah. This just shows, again, the -- these type four reef, four slope deposits that we have immediately above our proposed injection zone, we see them in wells in the area, and then, as you go off to the west, they do tend to go away, but in the area where we are, we see about 670 feet of those very type deposits above our zone.

Q. And those type deposits, in your opinion, will protect the Capitan?

A. They separate us from the Capitan.

Q. All right.

A. And then this was the last concern that I mentioned, and that is that the -- these producing zones are significantly lower in the, in the Bone Spring and the Avalon. They are a good -- you can see like the Bone Spring 8300 feet is approximately over 1000 feet of sandstones, silt stones and very tight shales between us and the Bone Spring from the bottom of the Brushy Canyon.

Q. Did you address the concern about the health and safety risks to nearby operators?

A. Yes. As I mentioned, I think, in fact, those risks are ones that they deal with on a regular basis, but they will be reduced because of the small size of our plume. In fact, those health and safety risks are reduced because you are no longer having to treat this stuff on the surface with iron sponge and moving large amounts of disposal material that Brian described earlier, which is a big benefit.

Q. All right.

A. So in summary, I think just right here as I got it, the Delaware Mountain Group provides necessary protection and is a viable option for -- and I think, frankly, in this area, and you after you see what David's seismic analysis showed, we believe it's a really good zone.

Q. Is it a fair statement to say that the particular zone must be evaluated on its own merits, regardless of whether it's in the Delaware Mountain Group or elsewhere?

A. Absolutely. I think it's critical for ensuring the safety of these operations, that the detailed information of each site be evaluated.

Q. All right. Notwithstanding your responses to the concerns, we did enter into --

CHAIRWOMAN SANDOVAL: I just want to interrupt real quick. I think, let's take a ten-minute break and give the court reporter a second, because there are not a lot of breaks in here.

THE WITNESS: I've only got one more slide.

CHAIRWOMAN SANDOVAL: All right.

THE WITNESS: And then we are switching to David.

CHAIRWOMAN SANDOVAL: Continue, please.

THE WITNESS: Just one.

BY MR. HNASKO:

Q. Let's talk about how these concerns were resolved in Exhibit 2.

A. Well, I think Exhibit 2 has been outlined and the Division and the State Land Office are well aware of these conditions, but they are summarized here. As you mentioned, after six months of the issuance of this permit, we'll file a C-108 for a Devonian redundant well, and we will complete the well no longer than 15 months after the OCD approves that Devonian well. We still need to prepare the application, make sure we can find a good location, et cetera.

Then no more than six months after placing the well into service, SCM will begin using the Devonian well as a primary injection well and maintain the Delaware Mountain Group well as a redundant well.

Q. All right. Just so -- we'll conclude with this if we can, Mr. Gutierrez, but just for the clarity's sake, is it a correct statement to say that because of these conditions you reached, agreed upon with the State Land Office and the OCD, your calculations of the 0.15 radius of the 30-year plume will never come to fruition. Is that fair?

A. It will only come to fruition if we inject 8 million a day for 30 years.

MR. HNASKO: Madam Chair, at this time we pass Mr. Gutierrez with the right to bring him back for more direct testimony on the specific characteristics of the well.

CHAIRWOMAN SANDOVAL: Okay.

MR. HNASKO: And with that, Your Honor -- Madam Chair, I would like to offer into evidence Exhibits 4 and 5.

CHAIRWOMAN SANDOVAL: Are there any objections?

MR. AMES: No objection.

CHAIRWOMAN SANDOVAL: From the State Land Office?

MS. ANTILLON: No objection.

CHAIRWOMAN SANDOVAL: Exhibits will be included.

(Exhibits Salt Creek 4 and 5 admitted.)

CHAIRWOMAN SANDOVAL: With that, let's take a 15-minute break, so we will come back at 5 after 11, so at 11:15 -- or 11:05.

(Recess taken.)

CHAIRWOMAN SANDOVAL: All right. It is 11:07, and we will come back to order.

Mr. Gutierrez, I think the Commission has some questions and then we will finish.

Does the Commission have any questions or wish to cross-examine this witness on what he spoke about prior to the break?

COMMISSIONER ENGLER: I do, yes.

COMMISSIONER KHALSA: Uh-huh, I do have a question.

CHAIRWOMAN SANDOVAL: You can start us off. Dr. Engler can start it off.

COMMISSIONER ENGLER: I'd like to try to get this right. Slide 37, I too also like figures more than words. So I want to ask, you have yellow on the highlighted yellow zones which you consider areas of porosity of greater than 12 percent.

So in the Delaware Mountain Group, as you explained it, it's a series of sands and shales that are coming off the shelf edge and being deposited. Would you agree then that -- and like your yellow indicators show that you have quite a bit of lateral variation and vertical variation of these sands.

THE WITNESS: In a general sense, I would agree with Delaware Mountain Group, but what we saw with this seismic is that at least from the Bell Canyon for about 200, 300 feet, we had a pretty massive sand. I mean, it did have some stringers in it, but it was pretty massive.

COMMISSIONER ENGLER: So you are going to have some really good sands, a certain thickness, and a series of small ones. And your log data as you point out with the yellow coloring shows a lot of sands with certain porosity greater than 12 percent.

THE WITNESS: Correct.

COMMISSIONER ENGLER: Hopefully you have something off the top of your head here, the Eagle Feather Well, that be the well to the left of your proposed well.

THE WITNESS: Yes.

COMMISSIONER ENGLER: How many feet greater than 12 percent?

THE WITNESS: In the Eagle Feather?

COMMISSIONER ENGLER: Yeah.

THE WITNESS: I don't know off the top of my head, but I would say probably about 400.

COMMISSIONER ENGLER: So about 400 feet, and that's 12 percent -- I guess I better ask a little bit of detail here. When you are saying porosity of 12 percent, you are planning total porosity?

THE WITNESS: Yes.

COMMISSIONER ENGLER: That well has two porosity pools, the density and neutron. So I'm assuming you are using some type of cross plot porosity out of that?

THE WITNESS: That's correct.

COMMISSIONER ENGLER: Is that correct?

THE WITNESS: That's correct.

COMMISSIONER ENGLER: So I'm also going to say or ask, since these are mostly sands, you have corrected those calculations for the fact that it's sands and not limestone?

THE WITNESS: Absolutely. Because, I mean, we are using that correction on the logs.

COMMISSIONER ENGLER: Well, let me -- I forgot to check. The logs were one run on an assumed limestone.

THE WITNESS: Yes.

COMMISSIONER ENGLER: Since you did cross plotting --

THE WITNESS: That's right.

COMMISSIONER ENGLER: -- in the sand, you have taken that into account, the lithology variation?

THE WITNESS: We have indeed.

COMMISSIONER ENGLER: So you have about 400 feet of 12 percent, and on the log to the right to the well, you know, you probably have, again, I would say more, maybe 600 feet.

THE WITNESS: That's right. That's right.

COMMISSIONER ENGLER: All right. So what confuses me then is, one of the things that I want to ask is, in your volume calculations, you know, it's very important because you are trying to estimate a radius or area for an injection area here, is you use 17 percent porosity and not 12.

THE WITNESS: That's right. Because -- because in the areas where we -- I mean, what we did for the purpose of this cross-section is to outline where we had 12 percent or greater, but in many places we had like 17, 18, 20 percent porosity in those areas, so we took what we felt was a representative average over the -- the injection zone, and we basically reduced the footage to accommodate for that.

COMMISSIONER ENGLER: Well, in your calculations you are using 17 percent as an average over a 900 foot thickness, not 4- or 500. That's in your Table 3 in your table data. So when you're calculating a higher porosity, your thicknesses should be less than what you show here in terms of porosity, therefore your total volume should be different.

So there is a disconnect to me in the petrophysics between what you identify as 12 percent and what you are using in your slide. So if you -- you are using 900 percent at 17 percent, that's probably way overestimated because you are showing 4- or 500 feet at 12 percent.

THE WITNESS: Right.

COMMISSIONER ENGLER: So my position here is that I think those volume calculations are way underestimated in terms of the area because of that. Okay.

Another question. So in your volume calculation you have an SWR, you call it -- I guess you call it residual water saturation, I like to call it water plume.

THE WITNESS: Yes.

COMMISSIONER ENGLER: The main difference is what you are using for mobile displacement -- mobile water, mobile fluid which you are displacing with your injection.

THE WITNESS: Yes, sir.

COMMISSIONER ENGLER: So 36 percent is your, is your residual water. I asked this last time, and I still don't know. How did you calculate that in a particular zone like this which is not oil saturated?

THE WITNESS: Well, we just use the, the RW calculation to cal -- let's see, I think I've got to refer back to the application because I have that in there.

COMMISSIONER ENGLER: It's dangerous when you have a practicing professor on it.

THE WITNESS: That's all right. I mean, I have to say also that in part experience and our calculations on here is informed by the detailed FMI logs, et cetera, that we got on this other well in Texas that is very similar stratigraphically, and what we found is that it has significantly higher porosity than what we were able to derive from those adjacent logs. Of course we only know what it is at this particular location once we drill the well and analyze the logs.

COMMISSIONER ENGLER: I have no doubt about that, I agree with you there, but you have to have -- you have a certain set of data right now, and that is what's presented in evidence that I'm using to try to make a decision. If you have other data that you would -- FMI data that you are willing to show, I can analyze that just as well, but that's different evidence or data. This is what I'm looking at right now.

My -- my main concern, if you go to -- let's see what slide -- it's the figure with the circles on it, 4 or 5. That's fine. You know, the main thing is your -- you've calculated an area based on what I would call is over-optimistic values, hence your area is small.

Would you agree that there is a certainty in a lot of this data, as you said, there's only so many well logs and so much data, so wouldn't you agree then that instead of having a single area, maybe have a range of data in like an uncertainty analysis, and therefore you would have a range in your drawn area of injection such that you go from different parameters from 400 feet of whatever porosity up to your mids and your max, and if you generated these areas in terms of this range, that would help maybe, again, demonstrate where this particular bubble would go. Correct?

THE WITNESS: I think where it might help is to more accurately bound the limits rather than presenting a certain specific projection which I would agree with you is, is on the optimistic side from the porosity perspective.

However, I will point out one thing, one of the practices that we used to do -- we haven't been doing it, but we certainly could do it -- again, is we would -- in order to deal with that uncertainty, what we typically had done in the past would be to show the radius of injection after 30 years with both the proposed maximum volume and twice the proposed maximum volume. Okay?

So I mean, in a way that is accommodating for these uncertainties in the porosity and in the thickness of the specific porosity because we are basically saying we are putting in twice as much fluid as we -- as we anticipate ever putting in, and what we find, and I think we will find if I -- if we were to do what you just described in terms of a calculation is that because that volume expansion, it's not by any means linear.

I mean, in other words, you -- if you have less volume, or if you put in twice as much volume, that doesn't mean the plume is twice as large, obviously. And so that is one way we have handled that uncertainty before. It might be equally useful or perhaps more instructive, and I mean, that would be an improvement in our process, and I take that as a good suggestion, to use a range rather than, than a fixed number.

COMMISSIONER ENGLER: Well, I know you are looking at uncertainty in certain operating conditions such as changing the volume of injection rates, and I think that's a correct approach in terms of what if this happens in terms of that.

What I'm seeing is the uncertainty that I would like to see is related to the petrophysic properties because that is also another set of parameters that are influencing that calculation.

THE WITNESS: Sure.

COMMISSIONER ENGLER: So to me, when I see this, because right now you are strongly proposing, because of that area, that that area is so small that the influence is going to be minimal or zero, and -- and to me, I like to see more of uncertainty variation there so I can make a better decision.

If I, if I even went -- just -- again, this would be off the top of your head, even if I said I reduced your porosity value to 12 or your thicknesses down from 900 to 400, like you said, that area is going to expand.

THE WITNESS: Yes.

COMMISSIONER ENGLER: If you put that area onto that map, would you suspect that you would see some significant change?

THE WITNESS: I would suspect that I would see probably somewhere in the neighborhood of a 300 to maybe 400 foot range increase in that radius. So let's say instead of 800 it might be 1300 or 1200.

COMMISSIONER ENGLER: And again, on that map when you have that, that relative to the wells that you have displayed --

THE WITNESS: Right.

COMMISSIONER ENGLER: -- you could then have something, you know, that would influence those wells, or you say it's still -- again, that that's still a small radius to deal with uncertainty, there is not really going to be an impact on those wells.

THE WITNESS: Well, remember, if I can go back to showing another slide that shows the wells around -- first of all, by the way, I want to just make clear that this slide, this is the one-mile circle, this is not the plume.

COMMISSIONER ENGLER: I know that.

THE WITNESS: But if we go back to this one, let's just say that, you know, we say that the most optimistic look of this is what you see right here. If you added 300 or 400 feet, it would be about like this. You see -- and now what I wanted to do is go back to one of those slides from the SLO objection because it shows where the nearest -- here we go.

Okay. So here you can see, I mean, even the nearest saltwater wells, I mean, we are talking not a few hundred or 1000 feet away, we are talking like 1, 2, 3 miles; right. Here six, seven miles, nearest production over seven miles away. And there is no way that even with the uncertainty that we are talking about, even if you were -- which I don't believe that, based on my experience and looking at the well logs that I have seen there, if you were to take the most pessimistic look, you might, at worst, increase that by 5- or 600 feet, not quite double it, the extent of this plume after 30 years.

So it still is going to be very, very far away from any potential production in the, in the Delaware Mountain, and it -- I mean, these other wells that are already drilled there, the vertical portion of those wells possibly could be partially invaded, that's true, but again, this is after 30 years of operation.

COMMISSIONER ENGLER: Right. Yeah, the first top diagram is the Delaware, I understand that. My concern of course is with the radius of this area of course, what the nearest well, like you said, there are some horizontal wells, their vertical borehole, I guess, is away from you, and then there are the green dots. So again, if I expanded that radius --

THE WITNESS: But all of these green dots, remember those are all --

COMMISSIONER ENGLER: Shallow.

THE WITNESS: These are all either -- these are shallow, yes, right here, but -- or they are vertical components to horizontal wells. They are not -- there is no, no producing wells in the Delaware Mountain anywhere in that area.

COMMISSIONER ENGLER: Right. But there are boreholes penetrating through the Delaware.

THE WITNESS: Nine of them, yes, within a one-mile radius.

COMMISSIONER ENGLER: It's not the concern so much as to the Delaware as to what wellbores are there to penetrate that, because, again, if I have this TAG gas going to a reservoir, and if it migrates and is going to hit an existing wellbore, you know, that could really lead to a lot of issues or problems. That's what I'm -- that's why you are trying to display in terms of what the radius is and why it's not going to happen.

THE WITNESS: Yes.

COMMISSIONER ENGLER: One other, one other last question on this topic, though. Is it possible, you know, you identified, like you said, that you have seen some of these sands are fairly thick, nice clean sands, you know, 20, 30 foot or whatever they might be, is it possible, based on the nature, deposition and the lenticular nature of these type sands that when you inject, the majority of the gas will go into that high porosity, high perm zone, and if so, what kind of monitoring or what kind of steps is Salt Creek going to try to do to make sure they get conformance on injections all across that major zone?

THE WITNESS: Well, there -- in answer to that question, I mean, we are going to evaluate what are the best zones when we drill the well and log it and core it, and then we are going to perforate selectively those zones. We are not perforating that entire interval.

COMMISSIONER ENGLER: Right. But the zones that -- so from the 900 feet or whatever you are saying that it's going to take, you are going to perforate only certain zones that are going to be, I guess, have the highest value to you, highest porosity?

THE WITNESS: Right. I mean, we are going to perforate the entire interval, but we are going to exclude zones that we know won't take any fluid based on the logs.

COMMISSIONER ENGLER: When you start injecting, how are you going to know that all the zones that you perforated take that gas?

THE WITNESS: Well, when we do our step rate test initially, we do a DTS profile so that we can see which zones took the majority of the fluid from the step rate test, and by that is what we will presume that those zones are going to take the majority of the TAG. And the only -- the way to monitor the overall effect is by monitoring the change in bottom hole pressure in the well itself and -- but there is no direct way to monitor exactly how far that plume goes out.

COMMISSIONER ENGLER: Would you agree with me, the fact that you have the different sands like that and certain sands have much better capability of injectivity, that the -- then your -- since your volume calculation, since your area is so dependent upon that volume, that you are going to have areas that are going to go much further out and others that maybe won't go so far out because of the variation in those properties?

THE WITNESS: Yes, it could.

COMMISSIONER ENGLER: So would that not also then impact -- again, I could have potentially a main zone that might actually go out and drain and have an injectivity rate that could be thousands of feet.

THE WITNESS: I do not agree with that at all. I do not think that you could have a zone that, in other words, a zone that's just going to preferentially push out thousands of feet away from -- you know, again, you have to remember the kind of volumes we are talking about. We are talking 3000 feet a day. This is not a 10- or 12,000 barrel -- 3- to 3200 barrels a day. It's not a 12- or

15,000 barrel a day saltwater injection well. I mean, so the -- the volumes relative to the available volume in, in the, in the reservoir are very small.

COMMISSIONER ENGLER: In your experience, since you have done many of these, so have you seen some of that, you know, like post completion data, and you can see something in terms of a large area, large thicknesses that are being injected and can -- have you seen things where you see equal distribution through that? Or in terms of injection, in your past experience, what have you seen?

THE WITNESS: Okay. It's limited because, as you know, I mean the whole point of trying to keep the integrity of the injection zone is you don't -- it's not like we are going to drill monitor wells to try and see where the plume is going. But we have had several instances where by the situation we have been able to determine how far the plume has extended.

And I will give you two examples here in the state that have been heard by this Commission, and Linam AGI for DCP Midstream is one of them. We put in a single AGI well into it, and it's not in the Delaware Mountain, but it is in the Wolfcamp near Hobbs in a -- in a not productive portion of the Wolfcamp, but a reef detrital portion and that had a similar kind of thickness over which we calculated that volume and estimated what the plume distances would be.

And we injected into that well for like seven years before we obtained a permit for a redundant well in the same zone to be drilled at that same facility about 450 feet away from the -- and in this case we had an estimated plume that would be about, I would say, .3 miles in, in radius after 30 years, so it's about double of this one.

And based on that same calculation, we determined, after seven years, how far that plume would have migrated from the injection of the first well using not only, not our predicted maximum rate, but the actual rate that we had injected during that period of time.

It predicted that we would see acid gas within about 400 feet, approximately, of the AGI at that time. So one of the things that we had to do when we drilled the redundant AGI was to be very careful. Obviously we had some loss circulation zones and a lot of other stuff I won't go into, but we basically said we are going to have to extend the intermediate casing all the way down to the top of injection zone because we want to make sure that when we drill into that injection, since we have been putting 30 percent acid gas into that, that we can control that when we drill into it.

So, long story short, we drilled into the zone after having injected for that period of time, and nowhere within the entire injection profile did we get anything more than a few hundred ppm of H_2S when we expected to be in basically 15 percent H_2S.

One of the -- so that's one example. That's a direct measurement after having injected to evaluate that. We had a similar situation where we injected -- where we put a redundant well long after another well had been drilled at Targa's Monument Facility and had a similar experience. We had anticipated entering essentially the TAG plume with the well based on how long it had operated, and we didn't. I mean, so --

COMMISSIONER ENGLER: I think those examples are interesting. I think those are things that are helpful. It does lead you to, if you are expecting to hit it and you don't hit it, then that would suggest that your original log and model wasn't quite right to start with.

THE WITNESS: That's right.

COMMISSIONER ENGLER: But that is a good example. I appreciate that. No further questions, I will stop now.

CHAIRWOMAN SANDOVAL: Ms. Khalsa?

COMMISSIONER KHALSA: Mr. Gutierrez, in your -- you are telling us that there were no faults mapped in the immediate vicinity. I wondered if you had a map of regional faults that were mapped in that area.

THE WITNESS: We do, and David will present that, and we did look at the seismic and the one fault I mentioned to the north, northeast.

COMMISSIONER KHALSA: That's it.

CHAIRWOMAN SANDOVAL: So as a part of the changes that were agreed upon with the State Land Office and the OCD, so you will be drilling a second Devonian well. Where is that going to be located?

THE WITNESS: I don't know yet. I haven't done the application yet.

CHAIRWOMAN SANDOVAL: Do you expect it's going to be located on the same site?

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: Okay. So near the other one?

THE WITNESS: That's right.

CHAIRWOMAN SANDOVAL: So can you go -- I think it was Slide 25. Yeah. So it looks like there is an existing SWD just southwest. Is that what that little triangle is, the little blue guy?

THE WITNESS: Yes.

CHAIRWOMAN SANDOVAL: Where is that injecting into?

THE WITNESS: I believe that's in the Delaware Mountain Group.

CHAIRWOMAN SANDOVAL: The same formation that we are planning to inject in --

THE WITNESS: That's correct.

CHAIRWOMAN SANDOVAL: -- for the --

THE WITNESS: I believe. I would have to go back and look. It isn't? So I would have to go back and look at the application.

CHAIRWOMAN SANDOVAL: Okay.

THE WITNESS: But I didn't think it was in the Delaware Mountain Group because the nearest ones we found were the ones I showed early.

CHAIRWOMAN SANDOVAL: So either the Delaware Mountain Group or Devonian?

THE WITNESS: I don't know. If you could ask David the question, he'll -- I just don't remember.

CHAIRWOMAN SANDOVAL: Okay. Then most of my questions I can direct towards David. So until that second well is drilled and in service, how do you guys plan to handle any situations where the initial well goes out of service?

THE WITNESS: I mean, I guess the -- the -- it would depend on what the initial well going out of service means. If it means that we had a problem with the compression and that needed to be resolved, then the facility has a limited amount of flaring that is permitted under their air permit, they would, I would presume, flare according to those limitations.

And then if they, if the well was not repaired and working when those limitations would be reached, they would have to shut in production.

CHAIRWOMAN SANDOVAL: And then you would basically just force the producers to flare or shut in?

THE WITNESS: That's correct. That's the normal way in which any gas plant operates.

CHAIRWOMAN SANDOVAL: It is. That is correct. But I mean, this is a slightly different situation here when you have H2S. Has there been any communication with the producers as to how you would manage that situation if it arose so that there was proper planning to make sure there were no health or safety impacts due to flaring either at the plant or down the production side?

THE WITNESS: I don't know. That would be a question for Salt Creek. We have not had those discussions with producers. That is not our role.

CHAIRWOMAN SANDOVAL: Okay. So it doesn't really answer my question, but thank you.

THE WITNESS: I'm sorry, I can't answer -- the answer is no, we have not -- we at Geolex have not had any of those discussions.

CHAIRWOMAN SANDOVAL: Okay. Fine. Does the Land Office wish to cross-examine right now?

MS. ANTILLON: No questions.

CHAIRWOMAN SANDOVAL: Does the Division wish to cross-examine right now?

MR. AMES: No, Madam Chair.

CHAIRWOMAN SANDOVAL: Is there any redirect of this witness from the applicant?

MR. HNASKO: Yes, Madam Chair, appreciate that. And point of clarification, Madam Chair, if we -- I'm used to a different forum.

CHAIRWOMAN SANDOVAL: Right, that's fair.

MR. HNASKO: Madam Chair, to answer your question, we can recall Mr. Perilloux to discuss the issue of communication with the operators in the event something were to occur. We would be happy to do that.

Brief follow-up if I may. You can sit and get comfortable.

REDIRECT EXAMINATION

BY MR. HNASKO:

Q. Follow up on the questions of Dr. Engler, if I get this correctly, Dr. Engler was proposing a more conservative analysis of the diameter of the plume, and there are a few ways to do that, I suppose; correct?

A. We would do it in the same way, we would just presume that there -- we would just allow for lower volume in the reservoir.

Q. Why don't we -- we can take a range of volume, right, and that would give us a more conservative or worst case scenario of the size of the plume after a while, after a 30-year period. Is that a fair assessment?

A. Yes.

Q. We can also reduce the porosity. Instead of assuming an average of 17 percent we can use 12, or even a lower number, and that again would be a conservative precaution when evaluating the worst case scenario of plume size. Is that a fair assessment?

A. Yes, sir.

Q. A third way would be to reduce the time, in other words, the injection time. Instead of 30 years, assuming an injection over a 30-year period, assume it for a much lesser period of time.

A. Well, of course. I mean, the bottom line is just a reduction of volume, so yes, that is.

Q. All right. So if I look at Exhibit 2, if you would, please, the special conditions, I'm trying to calculate the limitations on time and how that would affect, if at all, the estimates you have put forward for the size of the plume after a 30-year period.

So one of the conditions, if I understand it correctly, is to submit an application for a Devonian well within six months after the approval of this particular

application assuming the Commission does so. Is that correct?

A. Yes, sir.

Q. After that application, we don't know the time for the Commission and OCD to act on it, and other parties, but assuming six to eight months, 12 months is a reasonable time to get a hearing, in your estimation?

A. Yes.

Q. So let's say 18 months. If that's approved, we have another 15 months thereafter to place it in service; is that correct?

A. Yes.

Q. All right. So where are we?

A. Three years. Two and a half years down the road.

Q. So at that point in time it's essentially going to be the primary well, with the existing Delaware Mountain Group well as a redundant well; correct?

A. Yes, sir.

Q. So that's a three-year period. And would it be a fair assessment to state that the calculations based on a three-year injection assuming volumes you have estimated would be much different than the calculations of the plume after a 30-year injection?

A. Absolutely.

Q. How would that be? From my own perspective it's

ten percent.

A. It would be -- it doesn't correlate directly in terms of, like I said, the linear volume, but probably in terms of the volume that you would see, it would be even less than ten percent of that.

Q. Is, based on your experience and opinion today, would imposing such a time constraint and effects this has on volume limitations satisfy some of the concerns raised by Dr. Engler concerning the conservative estimate of the size of this plume over time?

A. I believe so. I mean, clearly there's one other thing that we haven't talked about that affects that estimate, and that is that we estimated the injection to be 8 million a day from day one for 30 years. And clearly, the well is not even injecting anywhere near that volume now, and based on the expansion plans that Brian testified to, probably not going to even reach that 8 million volume in the, this time frame that we are talking about.

So we are even -- you know, by even using the 8 million for that period of time, that's a conservative move, also.

Q. Okay.

MR. HNASKO: Thank you, Madam Chair. I will pass the witness.

CHAIRWOMAN SANDOVAL: Does the applicant have any more witnesses?

MR. HNASKO: Yes, Your Honor, we do -- or Madam Chair. You are going to be Your Honor by the time we get out of here.

MR. AMES: She is fine with Your Honor.

CHAIRWOMAN SANDOVAL: That is my expectation.

MR. HNASKO: May we proceed?

CHAIRWOMAN SANDOVAL: Yes, please.

MR. HNASKO: Our next witness, Salt Creek calls David White.

DAVID ALAN WHITE

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MS. HARDY:

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

A. David Alan White.

Q. Where do you reside?

A. Albuquerque, New Mexico.

Q. By whom are you employed?

A. By Geolex Incorporated.

Q. What is your position with Geolex?

A. I'm a geologist and project manager.

Q. Are you familiar with the matters addressed in Salt Creek's application?

A. I am.

Q. Have you previously testified in a Commission hearing?

A. I have not.

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

A. So I received my bachelor of science in geology from the University of Tennessee. And I did my master of science at the University of New Mexico. At Geolex I've contributed directly and prepared -- or I have prepared and worked directly with Mr. Gutierrez to prepare injection well applications for New Mexico, for the NMOCD, for the Texas Railroad Commission and associated applications with the Bureau of Land Management.

I have conducted seismic survey reviews to support many of these injection well applications that included analysis of seismic surveys, that included model simulation or fault slip analyses model simulations. I have gained experience in project management overseeing the drilling and completion and commissions of acid gas injection wells and provided support, geologic support for AGI projects.

Let's see. We -- I have assisted Midstream operators with regulatory support for AGI systems, as well as AGI well maintenance and also contributed to designing and administering acid gas injection system training sessions for the Midstream operators in the basin.

MS. HARDY: Madam Chair, I tender Mr. White as an expert in petroleum geology.

CHAIRWOMAN SANDOVAL: Do the Commissioners have any questions for the witness?

COMMISSIONER ENGLER: No objection.

CHAIRWOMAN SANDOVAL: Okay. The Commission will recognize the witness as an expert.

BY MS. HARDY:

Q. Mr. White, let's look at Slide Number 46 which discusses the seismic review. Did you evaluate the potential for induced seismicity in the proposed location of the well?

A. I did.

Q. What were the components of your analysis?

A. So our analysis, first off, this analysis was not formally requested as part of this application, but with our experience in other applications for saltwater disposal wells that have been requested by the Division, we chose to include it as an important portion of this application.

And it consists of two, two components. First being an analysis of seismic or of 3-D seismic data with the main focus of identifying any faults in the area or subsurface structures that might be affected not only by our proposed injection scheme, but by what's going on around us, whether it be other saltwater disposal wells or other injection wells of any type.

Upon that review of the subsurface data, we then take what information was gleaned from that and conduct a fault slip probability model based on that specific injection scenario.

And for Salt Creek, this fault slip modeling scenario consisted of a six well injection scenario over the full duration of at least 30 years of injection at the anticipated maximum injection rates for each well. And to complete this evaluation we utilized the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential Model.

Q. Looking at the next slide, can you describe the seismic review that you performed?

A. Yeah. So shown in the figure here is the results of that initial review of seismic survey data. We evaluated courtesy of Ameredev LLC, we were able to evaluate and discuss and evaluate their interpretations of the South Lea Seismic Survey, and the map shows the results of these -- this evaluation.

Within the general vicinity of the proposed Salt Creek AGI we found potentially two faults east of the location, striking approximately NNW to SSE, approximately three miles from the proposed AGI.

To add to this evaluation, we reviewed NMOCD well records to identify nearby injection wells in the area, and those are shown by the blue dots. There were five additional injection or saltwater disposal wells, in addition to our proposed AGI, located in the western portion of the area of review.

Our initial thoughts on the subsurface structures and the injection wells, our initial reaction to this was we didn't feel there was going to be much of an impact based on this injection scenario due to the observation that the injection wells mainly being concentrated in the western portion of the area and the faults being observed much further away.

Nevertheless we still decided to run the model just to ensure and have some sort of quantitative or modeling to support those opinions.

Q. Look at the next slide. Can you explain how you identified conditions of the fault slip?

A. So this is part of the model simulation which is -- perhaps people are familiar with the model, but it's deterministic and probabilistic model simulation. And one of the first steps it does, it would take the input parameters, whether it be the fault orientation, their length, their dimension and local stress field characteristics, and it would individually determine, based on those input parameters what conditions along the fault would be needed to induce slip.

And shown in the table there is the model predicted pressure increases at the fault mid points that would be required to induce slip. And I'm sorry I didn't say this previously, but there are two main faults or potential faults that we identified.

In order to depict their non-strictly linear form and the model simulation, they were broken up into six fault segments to characterize their actual expression.

Q. Okay.

A. So that's the first step in the model simulation is to identify the features and calculate deterministically what pressure increase would be required to induce motion along those features.

Q. Looking at the next slide, can you describe the injection zones that are in the model?

A. Yes. So this slide we see a table illustrating all of the injection wells, SWDs, and the proposed AGI that were included in the model simulation, as well as their API numbers and their simulated injection rates.

So these modeled injection rates do not reflect accurate or the actual injection rates. A lot of these wells, if you look at their injection records, you will see that their -- what they have actually reported injecting is much lower than the anticipated maximum volumes.

So if we -- if it was available in NMOCD records we would utilize the maximum injection volumes for this simulation. You will also see that some of them, I said it in the initial introduction, that the simulation was run for at least 30 years, but we have some wells, for instance the West Jal B and the Momentum State that began operation in 2017, so the model was allowed to run for those additional years to -- to accommodate for the previously-injected materials.

Q. Next slide?

A. Yes. The figure to the right, the next step the model takes is to take all of your injection parameters, as well as your reservoir parameters, and run the model over the duration and predict a result in pressure in response to that injection scenario.

So the panel to the right there shows the result at year 2050 after all six wells have been operating under those conditions. And it's not included in this, but the model will also return radial solution for pressure fronts, and as you can see, if you want to really look at the colors, by about less than three miles or around the three-mile mark you have significant drops in the pressure front. So in a sense the greater distances, you are really having only minor increases in pressure on the order of maybe 150 to 200 psi or so.

Q. What have you concluded as a result of your fault slip analysis?

A. So based on -- or the fault slip analysis model prediction suggests for this injection scenario that there is zero probability for induced seismic events along the features included in the model.

And in order to -- part of what the model does is when it -- as it is estimating the probabilities of slip, it not only determines or makes this calculation deterministically, but for this portion it calculates probabilistically across the range of uncertainties.

So when it's determining this section of the probability results, it may consider variations in dip of features, or variations in porosity within your reservoir or permeability within your reservoir. And allowing the model to -- or completing the simulation based on the model parameters input and the nearby injection wells and subsurface features in the area, this model has confirmed our initial observations that the faults and -- or the distance between faults and injection wells, both proposed and active in place, are -- is great enough that it's not predicted estimated to be a risk of slip in the area.

Q. In your opinion, is there any potential for

induced seismicity as a result of the proposed well?

A. Not under these conditions, no.

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

CHAIRWOMAN SANDOVAL: Does the Commission have any questions or wish to cross-examine the witness.

COMMISSIONER KHALSA: I have a question. Is it typical on any of these types of AGI projects to have seismic monitoring during operations?

THE WITNESS: I believe it is -- well, no. Let me refrain. For AGI projects I have not heard of any that do. I have heard that for some saltwater disposal wells there are operators that have real time seismometers. And I believe that it is in places like Alberta that it is more standard for that to be the case.

COMMISSIONER KHALSA: Thank you.

COMMISSIONER ENGLER: Go back one slide, please. So I guess first to clarify, if I remember right, so all of those SWD wells are all in the Delaware?

THE WITNESS: Yes.

COMMISSIONER ENGLER: So when you are modeling, obviously your AGI well is Delaware. They are all Delaware?

THE WITNESS: Yes.

COMMISSIONER ENGLER: In this simulation model, so that's very dependent upon whatever input parameters are put in?

THE WITNESS: It is.

COMMISSIONER ENGLER: I guess this is more of a, of a request in the future is I would really like to see that input data because any model is very dependent on that input data. So again, I'm not sure --

THE WITNESS: Well, the input data is included in the C-108 injection application.

COMMISSIONER ENGLER: I'm sorry, I missed that.

THE WITNESS: No, no, it's fine.

COMMISSIONER ENGLER: Because you have to be able to generate some type of characterization field so it can run that model.

THE WITNESS: Yes.

COMMISSIONER ENGLER: This pressure data, the result of pressure data, this is surface pressure or subsurface?

THE WITNESS: This is the -- this is subsurface.

COMMISSIONER ENGLER: Subsurface, yeah.

THE WITNESS: Yeah.

COMMISSIONER ENGLER: Okay. On the next slide on the fault slip potential, you mentioned -- and I might have missed this, and I apologize -- when they go through fault slip analysis, it's going to vary on a lot of parameters to see what was drilled, what will be -- what will occur, and what will be the outcome.

THE WITNESS: Yes.

COMMISSIONER ENGLER: So -- and again, this is -- if I missed this, I'm sorry, but again, it's sometimes for me nice to know what all those parameters are that were considered such that I know the range of everything that was happening. And I see in your conclusion or your final analysis it says it will be limited or no seismicity, but to me I like to see all what was considered into that.

THE WITNESS: Yes.

COMMISSIONER ENGLER: And that might also have been in there.

THE WITNESS: All the input parameters are all included in the C-108 application --

COMMISSIONER ENGLER: C-108?

THE WITNESS: -- on Page 14, along with everything.

COMMISSIONER ENGLER: You did good. Thank you

I skipped through because I went to Albert's stuff, so thank you.

THE WITNESS: Uh-huh.

CHAIRWOMAN SANDOVAL: So I'm trying to reconcile the map -- maybe two -- go back two slides, there. So here it doesn't like look like there any SWDs near, but on the map earlier in the presentation it looked like there was one directly southwest.

THE WITNESS: Yes, so I can clarify that. These are, on this map these are Delaware injection wells.

CHAIRWOMAN SANDOVAL: Okay.

THE WITNESS: The previous one, if you look at NMOCD records, the injection well or the saltwater disposal well that southwest of the proposed site, NMOCD records show that this well is in the Capitan Reef pool. However, logs for this well show it only going to I think about 2900 feet or something, so it's definitely not in Capitan and it's definitely not in Delaware.

CHAIRWOMAN SANDOVAL: Okay. So it's an older --

THE WITNESS: It is also included. It might be more difficult to find quickly, but in the C-108 application, there is a table of all wells within two miles or one mile. Both are in there.

CHAIRWOMAN SANDOVAL: Okay. So but we don't expect that, that there is going to be any issues with either this initial well that's going into the Delaware or the next well that's going to go into the Devonian with that injection well existing?

THE WITNESS: I do not believe so. I will need to find out which well this is, but I'm not sure if it's in operation.

CHAIRWOMAN SANDOVAL: Well, I think we have concluded with our questions. Does the Land Office or Division have any questions for the witness?

MS. ANTILLON: No questions from the State Land Office, Madam Chair.

MR. AMES: No questions, Madam Chair.

CHAIRWOMAN SANDOVAL: Thank you. Is there any redirect of this witness?

MS. HARDY: Just one question.

REDIRECT EXAMINATION

BY MS. HARDY:

Q. Mr. White, if you look at Appendix A to the C-108, does that list the wells that were evaluated in the fault?

A. Yes.

Q. Okay. And I think you have already testified that the saltwater disposal well that we have been discussing is above the injection zone; is that correct?

A. Yes.

MS. HARDY: That's all I have. Thank you.

CHAIRWOMAN SANDOVAL: Does the applicant have any additional witnesses?

MR. HNASKO: Madam Chair, we would like to recall Mr. Gutierrez.

MR. LOZANO: Mr. Hnasko, if it -- it's up to the Chair, but if you believe it would be helpful to recall

Mr. Perilloux, I believe they have questions for him.

MR. HNASKO: Absolutely. I was going to do that after.

MR. LOZANO: That's fine. I don't want to remove your order, but if you thought it will be helpful first, that would be fine.

MR. HNASKO: I think it would be. I'm going to take that advice. I think it would be better to call Mr. Perilloux.

CHAIRWOMAN SANDOVAL: Please proceed.

BRIAN L. PERILLOUX

(Previously sworn, recalled and testified as follows:)

DIRECT EXAMINATION

BY MR. HNASKO:

Q. Mr. Perilloux, you were in the hearing room when the Commissioner asked a question about what would happen if something went wrong with this particular well, and how the operators would proceed in such an event.

A. Right.

Q. Including protecting human health and environment.

A. Right.

Q. Could you explain what steps, if any, Salt Creek has taken to cover that potential?

A. Yes. Let me first describe the operation in very general terms, and then I'll address your specific question.

So in very general terms we have an amine system removing the acid gas, and that technology is a very proven technology with very clear understanding of what routine maintenance requirements are, and we have redundancy in certain pieces of equipment to minimize the risk of having to shut that unit down. In fact, I would say that an amine system is most happy when it's running continuously. It does not like to be interrupted in its operation.

Going specifically to the acid gas injection, our plan is, as we construct the injection well and the associated compression is to have redundant compression which is the most routine -- or the piece of equipment that has the most routine maintenance during a typical operation.

So just by example, if we look at the 8 million cubic feet of injection, we are planning to initially put in two, 4 million cubic feet of day compression units in.

Now, that correlates to our initial 35 million cubic feet of inlet gas. And I know I stated the CO2 was about 7 percent and the H2S was about 2, 2.5 percent, so I'm going to round up to make this easy math to 10 percent acid gas. At 35 million cubic feet of inlet gas we've got about 3.5 million cubic feet of acid gas.

So one of the two compressors that we plan to install will actually accommodate the full acid gas stream at 35 million a day inlet compression. As we increase the capacity of the system pursuant to our 80 million a day target, we would add a third 4 million a day acid gas injection compressor which effectively would give us a 50 percent redundancy such that we can perform any routine maintenance without interrupting the flow of acid gas.

So the equipment in the most likely scenario of interruptions is around routine maintenance as far as predictable. Certainly there are non-predictable events that occur, faulty instrumentation, lightning strikes, other things that take the facility down. In most of those cases what, what would take us down might also take a producer's well down. And what I would tell you is, we have 24-7 manned attendance at this facility such that the operators can respond immediately. So if something trips off line unexpectedly, we have the ability to bring it back into service certainly within a one-day time frame. Normally it's matter of hours, not days.

And in terms of routine maintenance, we do coordinate with the producers such that they can take wells down at the same time to do their routine maintenance while we are doing our routine maintenance. And we do have, at the field level, regular communications established between the producers and our operating teams to make sure that communication is undertaken routinely.

MR. HNASKO: No further questions, Madam Chair.

CHAIRWOMAN SANDOVAL: Do the Commissioners have any questions.

COMMISSIONER KHALSA: No.

COMMISSIONER ENGLER: No, ma'am.

CHAIRWOMAN SANDOVAL: So on -- you were talking about redundancy in terms of compression, but what would happen if something took the actual well down and it needed to -- there needed to be maintenance or something, and you have referenced potentially a one-day time frame. So what would the scenario be during that one day time frame say if it didn't take the production companies down?

THE WITNESS: Yeah.

CHAIRWOMAN SANDOVAL: I want to make sure that there are plans in place if -- if something does happen to that initial well before the second one is drilled and on line. That's the entire intent of having redundant wells because we have had issues in the past where the single well has gone down and there have been issues.

So if the well goes down before the redundant well is drilled, you have a plan in place for the compression, but if there is something other than that, you know, what do you have in place to make sure that, you know, human health and the environment are not impacted?

THE WITNESS: Yeah. So let me address that a couple of ways. One, I would first say, I am not a downhole well expert, and so I don't have intimate knowledge of all the inner workings of the well completion and what might cause a, a potential non-injectivity scenario.

However, being familiar with injecting into wells, I would suggest that, especially in this interim period of getting the redundant well, the probability of risk is very low.

Generally speaking, if a well performs adequately day one, it usually takes a matter of time before you start to see things like downhole plugging and that sort of thing that might restrict the injectivity.

So I don't want to speculate any further than that because, again, my knowledge of downhole subsurface conditions is limited. What, what I would say from a surface perspective is, if we have an event where we recognize there's a problem with the well that we do need to shut down for any case, we would coordinate that with the producer. And it depends on whether it's a complete shut down or partial or restricted flow to the well.

So I would suggest that a complete shut down is probably highly unlikely. A restricted flow scenario may be more realistic, and in that case, what we normally do and what we have done in the past to now even with running a triazine scavenger system is we actually contact the producer, and they shut in what we call the bad actor wells.

They have wells that are in excess of 25,000 parts per million, they shut off the bad actors and flow the cleaner wells to accommodate our capacity in the system. So we have a very active communication plan to address that, and the producers work with us. We work with them. We know in advance. We certainly plan for those events.

If we don't know in advance, it's usually an immediate phone call to say, "Hey, we have a restricted capacity. You need to respond accordingly."

Addressing the flaring event, I probably share most -- most people have an opinion that flaring is bad for the environment, and I agree with that. In this particular case S02 emissions are prevalent when you flare acid gas, which I think is, is -- well, it's certainly a cause of acid rain and that sort of thing.

So we want to minimize the flaring of H2S to form S02 by all means possible. Our state permit currently has a 95 ton per year limit. And to put that in perspective, at 10 million cubic feet a day of production, which is probably the maximum we are at today, if we flared 100 percent of the acid gas, we would probably produce about three and a half tons of S02 emissions a day. So it's -- it doesn't take very long to reach a permit limit. It's a matter of days, not even months.

Even if we were to acquire a Federal Title 5 permit, the limit is 250 tons per year. And at our design capacity of 80 million cubic feet a day, we could be flaring on the order of 8 to 10 million -- 8 to 10 tons per day of SO2. So, again, we would be even limited under Title 5 in a one-year operation.

So my personal goal and the goal of Salt Creek Midstream is not to flare. The other consequence to Salt Creek when we do flare is the amount of fuel gas necessary to flare TAG. And it's roughly about 20 percent of our inlet gas. So if we are taking in 10 million cubic feet of inlet gas, we remove a significant portion of the gas -- and I will go back to the 10 percent -- we remove 1 million in acid gas, we would need approximately another 2 million cubic feet of gas for fuel.

So of 10 million inlet, we only send 7 million cubic feet to market, which is not a very good strategy. What, what we really want to do is not flare, not use fuel gas, and that sort of thing. So there's no ideal perfect answer to prevent flaring. We consider flares emergency flares.

So if we have, again, the lightning strikes or equipment malfunction in the electronics is one of the more common causes, if we see that two or three times, or even half a dozen times per year, we want that to be measured in half a dozen times, let's call it 12 hours or less of flaring is our ideal goal, and redundancy helps prevent that.

And if we are flaring gas and shut our flare off or shut our facility off completely, you are correct in saying that backs up to the producers, and the producers would then, in turn, be required to flare in order to continue flowing their wells.

CHAIRWOMAN SANDOVAL: Yeah. So from our perspective, you know, we see flaring as a waste of a resource that potentially could be salable. You know, I would be interested, as part of the modification of your H2S contingency plan, having some of these scenarios mapped out and what the responses specifically would be, both your actions, how you communicate to the producers to ensure there is no impact to human health and the environment.

THE WITNESS: Right. I will take that advice, Madam Chair.

CHAIRWOMAN SANDOVAL: Do the Division or Land Office wish to cross?

MS. ANTILLON: No questions, Madam Chair, from the State Land Office.

MR. AMES: Yes, Madam Chair, I do have a couple of questions.

CROSS-EXAMINATION

BY MR. AMES:

Q. Mr. Perilloux, the Chair raised the question of the disposition of TAG when there are well issues prior to the construction of the redundant Devonian well. And in your testimony you mentioned a plan to handle partial or complete restrictions in injection. Is that a written plan?

A. I'm going to say our operating procedures that we have for the facility address temporary operations. I don't know that it specifically addresses all scenarios of, of what a temporary operation may be.

I would say the, the operations team, my direct operations managers and the field support staff are very well versed in, in what I would call typical oil and gas facilities. And response is usually a fairly routine response.

For instance a facility trips off, there are certain alarms that indicate what piece of equipment caused the, the shutdown or the failure, and the operators respond appropriately by addressing the specific shutdowns, rectifying the situation, and using the normal start-up procedures to restart the facility.

Q. Thank you. So the chair asked you if you would submit or supplement your H2S contingency plan to address some of these issues arising during temporary operations. Will you -- are you prepared to address the disposition of

TAG during these temporary operations in your modifications to the H2S plan that you will submit at the Chair's request.

A. I would like to answer that with a couple of thoughts. One, the requirement to file an H2S contingency plan is specifically to address the loss of containment. And under Rule 11, it does not specifically ask questions about operation and alternative operating states of the facility.

I'd have no, no problem committing Salt Creek to include that, as part of the H2S contingency plan, but I would just like to clarify that the specific requirements, in my understanding, is on loss of containment, and we are not talking about loss of containment here, we are talking about interruption of flow.

So I'm very well prepared, both individually and as a company, I can commit to including interruption of flow in the contingency plan, if that's, if that's what's being requested, noting that it's not a specific requirement of the state's rules presently.

Q. Thank you, Mr. Perilloux. I appreciate the clarification. So maybe I will modify the request. Will Salt Creek submit a separate written plan addressing the disposition of TAG during temporary operations?

A. Yes, if that is required, I would certainly commit to that, yes.

Q. We will leave it for the Commission to direct when and what to submit, but we appreciate your commitment to doing so as requested. Thank you.

A. Yes.

MR. AMES: Nothing further. Thank you.

CHAIRWOMAN SANDOVAL: Do you have any further witnesses?

MR. HNASKO: I have no redirect, and we do have a further witness, Madam Chair, which is Alberto Gutierrez.

ALBERTO GUTIERREZ

(Previously sworn, was recalled and testified as follows:)

DIRECT EXAMINATION

BY MR. HNASKO:

Q. Mr. Gutierrez, before we continue on with the design of the AGI system, I would like to go back and clean something up on Slide 25, and in doing so, direct your attention to the application, C-108, which is Exhibit 4, in particular, Appendix A to Exhibit 4, which identifies the wells within one mile of the proposed Salt Creek AGI 1. Do you see that, sir?

A. Yes, sir.

Q. All right. Were you able to garner some information on these particular wells that would be responsive to the Commissioner's questions?

A. Yes, and I can apologize for my bad memory.

Q. Don't worry about that.

A. But I would like to, if I could --

Q. Yes.

A. -- explain that and clarify. First of all, I want to explain that the blue square wells are wells that are permitted that would be the Ameredev horizontals. These greens wells that you see are all canceled Yates above our injection zone. These are not -- none of those wells penetrate the injection zone.

Similarly, I misspoke relative to this well that was pointed out by the Chair. This well is listed -- by the way, the API Number is 30-025-25957. And it is an active Yates saltwater disposal well with a TD of 3420 feet, so it is way above our caprock. Okay. It was spudded in 1978, and it has not injected -- it has been decreasing its amount of water injection over the past six years, and no injection has taken place, at least according to the NMOCD website records, no injection has taken place since 2018 in that well.

But again, this well, injection well, as well as all of these green producing wells of which there is a concern that if this modeling was too conservative could be incorporated in that plume can't happen because they are all completed above the injection zone.

The closest well that penetrates the injection zone here is this well, which is 30-025-26134, which is a well that was -- the well that was plugged back that I described that we used as a well in our cross-section. And those -- so that is three-quarters of a mile away, so even if you even doubled or even tripled the extent here, it wouldn't even reach that well. And certainly these others are not in the game because they are above the injection zone, so I apologize for not remembering that earlier.

Q. All right. Mr. Gutierrez, let's move on to the general design of the AGI system. I'll direct your attention to Slide 51. Could you describe for the Commission the design of the system, please?

A. Yes. The design of the AGI well is a fairly standard AGI design that involves the use of corrosion resistant materials in every aspect of the case -- of the design of the well. It is a well with surface casing extending down to 2080 feet which protects all potential fresh water.

And then the injection string extending beyond that with the lower most portion of that injection string being constructed out of CRA casing, and the injection tubing, the bottom portion of that also included as CRA casing, and it includes a subsurface safety valve, and a permanent packer, both of which are incoloy coated and completely corrosion resistant, and it also includes bottom hole pressure temperature monitoring.

If we go to the next slide, this is just a generic schematic slide that just shows the compression at a facility and the schematic going into the well. And if we just go to the next slide I can give you the details of the well.

They are laid out here, but if we just go to the next slide I can show you. That's easier. We have the surface casing here which will be cemented to the surface. Then the production string extended down through the injection zone of which the upper 300 feet where the packer is set will be CRA casing, as well as the design of the tubing immediately above the packer and the mandrel that holds the subsurface PT measurement equipment.

The annulus of the well is filled with diesel fuel corrosion inhibited and biocide treated diesel fuel that is measured and continually measured in terms of pressure at the surface in the annulus, and the well will then be perforated in the injection zone.

Again, the exact location and number of perforations will depend on what we actually find when we log the well. But this is basically the design that we have for the injection wells which are basically state-of-the-art design what is being used now in the industry.

Q. Including the casing and cement program?

A. Yes. The casing and cement program, the casing, all of the cement is cemented to the surface, and all of the cement in the injection zone and immediately above the injection zone extending through the CRA section is completed with well -- with resin well loss or equivalent cement, which is a corrosion resistant specifically for sour gas wells.

Q. And in your opinion will these design factors for the well protect the integrity and safety of the well?

A. Yes. I believe it will.

Q. And how about ground water conditions, did you analyze the water wells within a one-mile radius of the area of review?

A. We did. Based on the New Mexico State Engineer's Office, we have one water well within the one mile area. It's about 9/10 of a mile to the southeast, has a total depth of about 800 feet. The surface casing will extend to 2080 feet and will be cemented to the surface and then have the injection string inside of that surface casing also cemented to the surface. And so therefore it will certainly protect all ground water in the area.

Q. How about surface water analysis?

A. Yes. I mean, clearly there is no standing surface -- there is no surface water bodies within the one mile area, but similarly this surface casing will protect any -- basically the shallow ground water and the surface water.

Q. Moving on to our next slide, if you -- what do you deem to be the key elements of this application?

A. Well, I think the key elements are the -- the quality and the stratigraphy and the reservoir characteristics of the proposed injection zone in the DMG from 5400 to 7000 feet. And the maximum injection rate of 8 million cubic feet a day for 30 years is what it was calculated on, as Dr. Engler so adequately pointed out, there is uncertainties there in the design and in the modeling of the extent of that.

And yet, because of, as I expressed in that earlier slide, the -- we believe that that uncertainty is well taken care of by the lack of wells in the immediate vicinity of the well, plus the fact that we are -- we have severely restricted this volume that we are going to put into that well based on the agreements that we have with the State Land Office and the OCD.

Q. All right.

A. Also, for the well itself, it's got all the appropriate materials and drilling procedures which will ensure the integrity of the design of the well and prevent the well itself as being a potential source of exit to the injection zone.

And then as we mentioned, the six wells that do penetrate the injection zone, there are only six of them. There are five active wells that are completed greater than 1300 feet below the proposed injection zone. Those are the horizontal wells we are talking about, and one plugged well that is .68 miles to the north, and this well is properly plugged and abandoned, and we provided that information to the state.

And so we don't, we don't believe that these wells will have any potential for -- for being a way to get material out of the injection zone.

Q. All right. At the risk of being redundant, would you summarize the geologic factors you believe in your opinion ensure the integrity and safety of this well?

A. Sure. I think that the wells that penetrate the target injection zone within the area of review are well isolated and protected from that, just as I described relative to the predicted plume. The cap, even with the uncertainties associated with them, because they are so far away and because the wells that are close proximity are well above the caprock.

The caprock is low porosity impermeable rock. We will confirm that through our coring and logging. The injection zone is vertically isolated from, and horizontally isolated from adjacent producing zones. The fresh water zones are all going to be isolated by surface casing and conductor casing.

The proposed injection pressure is well below the anticipated fracture pressure of the caprock. Separate testing we will do and we will verify what zones take what fluid, and that information will be shared with OCD prior to when we perforate the well, because in this situation we are going to have some communication.

We always have communication with the OCD about where we are going to perforate things, but in this case, in particular, to address some of those concerns about the proximity of the Capitan Reef, those are things we will discuss with the OCD in that interim period before we perforate. So the proposed zone is fully capable of sequestering that gas over time. And for all of those reasons, I think that this well will be protective of ground water, fresh water resources, as well as correlative rights for other producing wells.

Q. All right. And Mr. Gutierrez, based on your permit application that Geolex prepared and the conditions reached between -- or among the OCD, State Land Office, and Salt Creek, what are you asking precisely for the Commission to do today?

A. Basically we want approval for the ability to construct this AGI well in accordance with the C-108 application, and we would like -- typically we ask for two years, but of course in this case we know that we are going to be drilling the well pretty quickly.

As a matter of fact, one thing I didn't mention, but that I think the, the Division is aware of, we have already submitted a C-101 and C-102 application for drilling permit and have paid the fees associated with that, and the district is waiting for the outcome of this hearing to approve those applications so we can move on.

We want to inject 8 million cubic feet a day for a maximum operating pressure of 2149 for at least 30 years, and we recognize that we are going to use the well as a redundant well, so this is somewhat modified by those constraints.

We will be begin drilling as soon as we get that C-102 permit on this order. I think we're planning to spud in February. We want to be able to resolve any small variations, like some of these things that may come up during drilling and the coring and logging of the well with the Division so that the Division's director and the Division's staff can approve those variations administratively.

Let's say, for example, that when we drill we find that really our injection zone is 20 feet higher, comes in 20 feet higher or 20 feet lower, that those kinds of things we can resolve with the Division administratively. And we believe that the well will enhance the reliability of the plant and that the project is supported by the adjacent producers.

The proposed well will dispose of acid gas safely, and the injection of TAG will only begin after the Rule 11 plan is submitted and approved by OCD with the required modifications of the AGI.

Q. All right. And the permit conditions agreed upon will be part of the order?

A. That's correct.

Q. And finally, I believe you were here when Mr. Perilloux affirmed that Salt Creek would indeed submit the written policy on interruption of the well, and the activities that would be undertaken to protect human health and the environment should that occur.

A. Yes, that's correct. I just want to clarify one thing also, and this is to make sure there is a clear understanding that if, for example, the plant goes down or the well goes down, it's not like there is TAG that is continuing to be made. If the plant goes down it's a two step process, so there is no like TAG other than what's in the system that would have to be flared. So it's not like there is a big store of TAG that we have to deal with if there is an interruption.

MR. HNASKO: Thank you, Madam Chair. Pass the witness.

CHAIRWOMAN SANDOVAL: Commissioners, do you have any questions?

COMMISSIONER ENGLER: No further questions.

CHAIRWOMAN SANDOVAL: Land Office, do you have any?

MS. ANTILLON: No questions, Madam Chair.

CHAIRWOMAN SANDOVAL: Division?

MR. AMES: None, Madam Chair.

CHAIRWOMAN SANDOVAL: All right. Is there any redirect of this witness from the applicant?

MR. HNASKO: No, Your Honor -- Madam Chair.

Do it one more time.

CHAIRWOMAN SANDOVAL: All right. So we will now hear from the State Land Office.

MR. AMES: Madam Chair, would it be appropriate to take a lunch break?

CHAIRWOMAN SANDOVAL: Oh, gosh.

MR. AMES: People might get a little testy.

CHAIRWOMAN SANDOVAL: Yes, it is 12:38 right now. Why don't we take an hour for lunch and come back at 1:40.

MR. AMES: Thank you.

(Lunch recess taken at 12:38 p.m. The proceeding resumed at 1:44 p.m. as follows:)

CHAIRWOMAN SANDOVAL: All right. It is 1:44 on December 11, 2019. We now will come back to order. We will now hear from the State Land Office.

MS. ANTILLON: The State Land Office doesn't have any witnesses today.

CHAIRWOMAN SANDOVAL: Okay. We will now hear from the Division. The Division may now make a brief opening statement -- oh, you already did that.

Will all persons who wish to testify on behalf of the Division please come to the witness table and stand so the court reporter may administer the oath.

(Oath administered.)

CHAIRWOMAN SANDOVAL: The Division may now present its direct testimony on the application. Please call your first witness.

MR. AMES: The OCD calls Phillip Goetze.

PHILLIP R. GOETZ

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. AMES:

Q. Mr. Goetze, please state your name for the record.

A. My name is Phillip R. Goetze.

Q. Where do you work?

A. I work for the Oil Conservation Division in the

Santa Fe office.

Q. What is your position there?

A. At this point I have been designated the UIC program manager and previous -- and also hearing examiner and other things, but mostly UIC.

Q. As the UIC program manager, what are your responsibilities?

A. At this point it is to make sure that the permits or applications provided to us are properly processed, to review the UIC program and ensure that the certain requirements that we have under our agreement with the EPA are enforced, and to provide the director with recommendations based upon our findings as a group.

Q. Have you prepared a curriculum vitae?

A. Yes, I have. It's been submitted as OCD Exhibit Number 1.

Q. Can you tell the Commission a bit about your educational background.

A. I'm a graduate of New Mexico Tech. Bachelor's of science in geology in 1977. I have been with the Division since 2013 in various capacities including doing the UIC program.

Prior to that I have worked with both private industry and general -- well, public interests such as the the Bureau of Land Management, United States Geological

Survey, United States Bureau of Mines.

As private entities I have worked with large corporations such as TetraTech and Roy F. Weston and smaller firms known in this area, such as Glorieta Geoscience, Charles B. Reynolds and Associates, Billings and Associates, and have covered a wide spectrum of both environmental, governmental and somewhat engineering aspects of geology.

Q. Have you testified before the Commission before?

A. On several occasions, yes.

MR. AMES: I move the admission of OCD Exhibit 1, the curriculum vitae of Mr. Goetze.

CHAIRWOMAN SANDOVAL: Are there any objections?

MR. HNASKO: No objection, Madam Hearing Officer.

MS. ANTILLON: No objection.

CHAIRWOMAN SANDOVAL: It can be entered into the record.

(Exhibit 1 OCD admitted.)

MR. AMES: OCD would ask that Mr. Goetze be recognized as expert in petroleum geology.

CHAIRWOMAN SANDOVAL: Do you have any questions for the witness?

COMMISSIONER ENGLER: No.

CHAIRWOMAN SANDOVAL: The Commission recognizes Mr. Goetze as an expert.

MR. AMES: Thank you.

BY MR. AMES:

Q. Mr. Goetze, have you reviewed Salt Creek's application?

A. Yes, I have.

Q. What is your opinion regarding the application?

A. We generally disfavor the use of the Delaware Mountain group as a disposal zone, and we have tried to follow a pattern of moving away from this interval for commercial, especially commercial disposal of saltwater.

But we have reached an agreement with Salt Creek with the participation of the State Land Office, and with that, came up with a set of conditions that we believe alleviates a lot of our concerns.

Q. Mr. Goetze, in your testimony just now you said that OCD generally disfavors Class 2 wells in the DMG formation for saltwater. Did you mean to include acid gas injection as well?

A. We do, anything in disposal we try to limit it.

Q. As a result of Salt Creek's agreement to the proposed conditions, what is OCD's position regarding Salt Creek's application now?

A. Well, with the -- after consideration and negotiations, we do not oppose this application.

Q. So let's take a step back to your earlier testimony about OCD's position generally disfavoring Class 2

UIC wells in the DMG formation. Can you explain in more detail for the Commission the basis for OCD's position for that?

A.   Over the last few years we have conducted several studies with the cooperation of the New Mexico Oil and Gas Association, and in doing so we have come to recognize that the Delaware Mountain Group has certain characteristics which give it a, a higher level of concern, especially with the formation parting pressure being lower.

We currently utilize a .2 psi per foot gradient. We have come to recognize that in certain cases where this has been approved, in the area of review we have had incidences of impacts to production as well as correlative rights.

The second concern, we have also had several cases involved with having the issue of drilling through a disposal zone. We've had several cases by operators trying to limit disposal there in the Delaware Mountain Group because of the fact of increased cost to change an entire plan for a development for an area would include increasing casing size, a cement program change, as well as drilling mud programs that have to be altered.

And then finally, in this case, you know, we are in the DMG, and we know that our targets are in the permian, so we always try to avoid having a situation where we create more of a problem.

And finally, the location and proximity to the Capitan Reef, because we are either in or adjacent, that we have always tried to maintain the reef at this time until further delineation as recognized in our primacy agreement underground source of drinking water. So we try to ensure that any activity and disposal, that we are not going to impact that source.

Q. Mr. Goetze, do you have an exhibit showing the location of the Class 2 UIC wells in the Delaware Mountain Group or DMG formation?

A. Yes, we do. We have Exhibit Number 2.

Q. Would you like to describe some things on that exhibit for the Commission?

A. Well, this is --

Q. Would it help the Commission to have that map out?

A. Well, we are going to see how well you can fold it back up. So basically this is a project which the Division has worked with NMOGA and independent operators, as well as disposal operators in, order to get a better understanding of what was happening with Delaware Mountain Group and injection.

For clarification, we will make note to the bottom, right-hand side of the map, you will see the proposed Salt Creek AGI well approximate location. What is plotted on here are all of our Delaware Mountain Group disposal wells.

And an outline has been shown, and this was developed by NMOGA, as to what was concern for them at this this time which was the potential for injection impact in Avalon which would be top of Bone Spring.

There are also included in here several red circles. These are areas where there have been historical or demonstrated influences in Avalon, as well as the Brushy Canyon production.

One particular point is in the middle there is an oval which says, Application to Revoke Authority to Two SWD Wells Denied, 15 -- Case 153 -- 23112 and then 15219.

Actually there's four wells in this area. What happened here, and this was the initiative to do the review, is that we had four disposal wells in close proximity, the result being that it washed out Bobco's production in the Lower Brushy Canyon.

So with this recognition, the Division, over the last few years, has tried to move away from disposal in the Delaware Mountain Group. And this is primarily our motivation we have now with looking at Devonian as being the principal disposal or ideal location, even though there are trade-offs, as opposed to Delaware Mountain Group at this time.

The only thing I would say about this is that each of these red circles represents the testimony of an expert saying injection will not occur out of interval and will stay within the area of review.

With that, this is one of our projects that we are continuing on and are utilizing as a means of filtering through applications.

MR. AMES: Thank you. I think that's the last question I have with respect to Exhibit 2. I will move Exhibit 2 for admission.

MR. HNASKO: No objection.

MS. ANTILLON: No objection.

CHAIRWOMAN SANDOVAL: Exhibit 2 is entered into the record.

(Exhibit 2 OCD admitted.)

MR. AMES: You folks want to put it aside or fold it up --

THE WITNESS: We offer services to fold it up for you after.

BY MR. AMES:

Q. Mr. Goetze, what standard do you apply when evaluating whether to approve a Class 2 UIC well?

A. The basis of it is the directives given in our statute which is to prevent waste, to protect correlative rights, to protect public health and environment, including underground sources of drinking water as directed under the UIC program.

Q. Do you have been an exhibit showing the conditions to which OCD, State Land Office and Salt Creek agreed?

A. Yes, we do. That's Exhibit 3.

Q. Is Exhibit 3 the same document as Salt Creek presented during their direct testimony?

A. That is correct.

Q. Do the conditions in -- do these conditions adequately address your concerns regarding UIC wells in the DMG formation?

A. Yes, and if adopted, the OCD will not be opposed to this application.

Q. Would you like to take a moment to look at Exhibit 3 and point out what you consider to be the most important conditions for this purpose.

A. Well, I think we have a set of general conditions which we have always attached, and those, of course, are on the last two pages.

On the front page, the special conditions, we recognize that, as Salt Creek was willing to have a second well, a redundant well, which is something that we try to have for our AGI sites now, we also are satisfied with the redundancy being that the Delaware Mountain Group well will be the one used as a backup or as an alternative, and the Devonian well being the primary.

We also went back and forth on where the locations of the top perforations should be. We do have a logging and the location of wells in this area is, is spread wide apart in correlations are very subjective, and Salt Creek agreed to actually go with the logging concept of actually looking what is in the hole, and therefore decide at that point where the perforation should be, as well as giving us a handle, are we really in the reef or not. So that's significant.

Other than that, most of these things were working out the details of scheduling.

Q. Thank you.

MR. AMES: I would like to move admission of OCD Exhibit 3.

CHAIRWOMAN SANDOVAL: Is there any objection?

MR. HNASKO: No objection.

MS. ANTILLON: No objection.

CHAIRWOMAN SANDOVAL: Exhibit 3 is entered into the record.

(Exhibit 3 OCD admitted.)

MR. AMES: Thank you, Madam Chair.

BY MR. AMES:

Q. So before we move on from these conditions, Mr. Goetze, I would like to follow up on Dr. Engler's concern in Salt Creek's dispersion model. Do you recall Mr. Gutierrez' testimony there is no way to directly monitor the extent of the plume in the DMG?

A. I do.

Q. And did you hear Mr. Gutierrez give examples of wells like the Linam Ranch AGI where the plume was much less than expected in their model?

A. I did.

Q. Do you consider the testimony of Mr. Gutierrez to be anecdote or data?

A. At this point I would only say it's not supported by data and is observations only.

Q. What does -- what does -- what do Mr. Gutierrez's examples show with respect to uncertainty in modeling plume dispersion from AGI wells?

A. Well, we are always looking for a better model. At this point we are limited by a single data point and our understanding from that single data point, the well that is a disposal well, what the characteristics of the reservoir are. Unlike other operations, such as production wells where we have more information in an area, we rely strongly on a lot of parameters that are variable, but still within a defined limit we know where we are starting from. As we go away from the well we always have concerns, especially if we have something that the Delaware Mountain Group represents, which is a little bit of a variation.

Q. And in the context of that variation, do you recall Dr. Engler's pointing out that the Salt Creek model over-estimated the percentage of porosity and the thickness of the injection interval?

A. Yes, I do.

Q. Do you think that these errors may have caused Salt Creek to underestimate the radius of the plume dispersion?

A. It may. Yes, yes.

Q. So do you share Dr. Engler's concern?

A. I do.

Q. Does the Commission requiring Salt Creek to install the Devonian well and make it the primary disposal well address your concern?

A. Yes, it does.

Q. How so?

A. Well, again, what was presented is that since we are moving away from the Delaware Mountain Group as the primary disposal well, we will have the opportunity to use something in a Devonian which we will have hopefully a better understanding reservoir-wise, and, in our opinion, something that would have less characteristics of getting away from it, so --

Q. Thank you. And finally, in your opinion, will the conditions agreed to by Salt Creek, the Land Office and OCD provide adequate assurance that the proposed well will not cause waste or harm correlative rights and protect public health and environment including underground sources of drinking water?

A. Yes, I do.

MR. AMES: Thank you. Nothing further.

CHAIRWOMAN SANDOVAL: Thank you.

Does the Commission have any questions?

COMMISSIONER KHALSA: I have one. Mr. Goetze, I am interested to know, if Salt Creek at some point decides for whatever reason they need to switch over into injecting into the DMG well because the primary goes down for some reason, are they required to inform you and you monitor that activity?

THE WITNESS: The permit is usually written for the capacity to be in either well.

COMMISSIONER KHALSA: Okay.

THE WITNESS: So typically we do get a sundry notice if it's been shifted, but there is no requirement that they do it in our agreement right now.

COMMISSIONER KHALSA: Okay. Thank you.

COMMISSIONER ENGLER: Is that it?

COMMISSIONER KHALSA: Yes.

COMMISSIONER ENGLER: Mr. Goetze, the map is very good. I have some questions relative to the map, so I will make you pull it back out. I just want to make sure, I have some clarifications and some questions. So this is only Delaware Mountain Group; correct?

THE WITNESS: Yeah, these are only Delaware Mountain Group wells that are presented on here.

COMMISSIONER ENGLER: So for the injection wells that you indicated, are there any other acid gas injection wells in Delaware right now?

THE WITNESS: We do have two, I believe. Let's check. We have the Red Hills AGI Number 1 which is operated by Lucid Energy Delaware, which is injecting in the Cherry Canyon.

And we have a second one, the Zia AGI, operated by DCP, and it is both Cherry Canyon and Brushy Canyon.

COMMISSIONER ENGLER: So in your experience and your knowledge, are you aware of any issues relative to those wells?

THE WITNESS: Not at this point. It would be -- and inform you that with regards to the Zia AGI, there are two there, the Zia AGI Number 2 was issued as a permit in the same interval, and there was an operator who said that they were kind of nervous about that and offered to foot the bill for drilling, in which case the well was reissued with the Devonian. So we have a situation where we do have a DMG and a Devonian well at the same facility.

COMMISSIONER ENGLER: For some of the issues that you were expressing about the Avalon, and then I think also some about the Brushy Canyon, these wells are injecting, whether it's gas or well for the water, are they mostly injecting into the Bell Cherry.

THE WITNESS: Yes. The case of the revocation of the two wells in the Bobco area, they migrated vertically and came out of interval and the quantity of water was significant, so it was a large volume.

COMMISSIONER ENGLER: And that was in the Bell?

THE WITNESS: That was Bell and Cherry.

COMMISSIONER ENGLER: Cherry. Again, you indicate these red circles as orange.

THE WITNESS: Red.

COMMISSIONER ENGLER: Whatever you call that, these were areas that were influenced by that injection --

THE WITNESS: Correct.

COMMISSIONER ENGLER: -- outside -- even though they were they were approved as injection. If I can clarify, you are saying these are areas where the injection has gone beyond what was originally approved?

THE WITNESS: Well, when considering the area of review, we have a mandatory one-half mile. So yes, we have areas where they have extended beyond that, so that raises the question of notification of correlative rights, as well as looking at any type of wells that have been plugged and abandoned or inactive outside of that area.

So when you do a review around a well, and you assess the plugging and cement work and casing work, if these flows go outside of where you have looked at these wells, then you are starting to head towards a penetration that may be a conduit to shallower formations.

COMMISSIONER ENGLER: Thank you.

THE WITNESS: You're welcome.

COMMISSIONER ENGLER: I'm done.

CHAIRWOMAN SANDOVAL: Do you think that there could be any current or future impacts to production from this injection well?

THE WITNESS: The basis for what we are mandated under statute is the prevention of flooding of any productive zone. Historically DMG offers a problem in that many of the assessments were done and made on plugged and abandoned wells that were vertical wells, and the design was prior to 2006 when horizontal.

The operators towards the Big Eddie, the horizontal wells would not appear until 2010, and actually that's the incident where Devon had a disposal well -- this is where we have this issue of where a disposal well was already approved, a horizontal came along, and all of a sudden they intercepted the disposal waters, even though Devon had addressed what they saw in the Brushy Canyon as being productive.

Now, I will weigh that with we are getting away from what has been identified by the professionals as being the highest potential for Brushy Canyon development, so I would say it is a low probability at this time.

CHAIRWOMAN SANDOVAL: But it's a possibility?

THE WITNESS: There is a possibility.

CHAIRWOMAN SANDOVAL: From your conversations with Salt Creek, did they present why they want to inject into the Delaware and not into the Devonian?

THE WITNESS: The presentation was stated that this was an ideal target, that the injection interval in the Delaware Mountain Group represented the best geologic and reservoir characteristics that they were looking for.

CHAIRWOMAN SANDOVAL: Thank you. Does the applicant wish to cross-examine the witness?

MR. HNASKO: I do, Madam Chair. Thank you.

CROSS-EXAMINATION

BY MR. HNASKO:

Q. Mr. Goetze, a lot of my questions are somewhat mooted by the agreement to the special conditions between

the parties. However, I just have a couple of issues I would like to clarify for the record.

A. Uh-huh.

Q. You talked about the Bobco production being washed out.

A. Uh-huh.

Q. And I think, was there four injection wells in that particular area?

A. That's correct.

Q. All right. And here we've got one; correct?

A. That's correct.

Q. All right. And I take it the outline of this area of concern was developed jointly by industry and the OCD?

A. Correct.

Q. And this area was chosen as a particular problematic geographic area of the Delaware Mountain Group for including both production and injection wells?

A. Well, it's problematic associated with what the potential for injection in the Delaware Mountain Group may have on the Bone Springs.

Q. Got it. So this line wasn't arbitrarily drawn, I take it, it was drawn based on data?

A. Correct.

Q. Which indicated to the parties that there might

be an issue in general if there is injection within this production area?

A. This is what they felt would be a concern for them in development of the resources.

Q. Would you agree with me that each injection area or each application for a particular injection area ought to be analyzed on its own merits with the data available for that, or should it be done in a general sense?

A. Unfortunately the four wells from Bobco were issued by four individuals at four different times. So historically we have just looked at single wells, so we have moved away from that because we understand the collective influence of several wells in the same interval.

Q. So when there are several wells in the same interval and not separated by much geographic space --

A. Uh-huh.

Q. -- that's going to exacerbate the problem I assume. Is that a fair statement?

A. Their proximity is an issue, yes.

Q. Let's look at the particular data for this well, because I think Madam Chair asked you a question, is there a potential it will impact production. And this proposed location is outside of the area of concern presented by the New Mexico Oil and Gas Association and the OCD; is that correct?

A. For the Avalon Shale, correct.

Q. And in this particular area, I'm not sure I have got this totally accurate, but looking at it from a birds-eye view, it appears, based on the exhibit, that the nearest production is about six miles away?

A. The statute states the flooding of productive horizons.

Q. I understand what the statute says, I just want to know where the nearest production is. I just want to get the idea in the record of what the actual distance is.

A. It is what has been stated in testimony already. It is some distance away.

Q. About six miles?

A. Uh-huh.

Q. Even if we were to accept the notion that the plume might have been overly optimistic in depressing its size, would you agree that it's certainly not going to get six miles away?

A. But again, under the rules, I have to look at the, cannot flood stratum which has the potential for production.

The Delaware Mountain Group went from being a disposal zone to a productive zone, and even though I don't have proven production there, I still must weigh the factors that once I have disposal in that interval, its mineral resource potential goes away.

Q. I understand, and I understand your statutory charge. I'm just curious about actual production, and we are looking at production six miles away. This plume is certainly not going to get there.

A. That's correct.

Q. And it appears that the proposed location of this AGI well is about a township outside the area of risk?

A. It's outside what industry has stated their concerns are, yes.

Q. And together with the conditions agreed by Salt Creek, I want to reiterate that you are satisfied that your statutory duty is satisfied to protect correlative rights and make sure that there is not any impact to potential production in this area?

A. I would agree that with the Devonian well, and the conditions that have been agreed to, that we have significantly reduced that risk.

Q. Thank you. I appreciate that. Thank you, Mr. Goetze.

MR. HNASKO: Pass the witness.

CHAIRWOMAN SANDOVAL: Does the Land Office wish to cross-examine?

MS. ANTILLON: No cross-examination.

CHAIRWOMAN SANDOVAL: Any redirect from the

Division?

REDIRECT EXAMINATION

BY MR. AMES:

Q. I would like to follow up on the questions from the Commissioner, Mr. Goetze. You were asked whether OCD gets notice when an AGI well operator switches between the redundant well, and I think your answer was, we usually get a sundry?

A. That's correct.

Q. But otherwise the permit doesn't require notice?

A. Unless it's specified, notice is not required.

Q. Would you object to the Commission stipulating or requiring that as a condition that OCD be given notice when Salt Creek switches between wells?

A. I would take back and modify that when we do have two wells systems, we have reporting that's provided for each well, so there are pressure monitoring and information, so we do see when they move back and forth.

Do we get operational notice once the monitoring -- the monitoring report comes after the fact. Notice at the time of the conversion is very limited, so -- but we would enjoy the factor of having some sort of notice to the district so they could be informed of when the well is changed over.

MR. AMES: Thank you. Nothing further.

CHAIRWOMAN SANDOVAL: Does the Division have any additional witnesses?

MR. AMES: We do not. The Division rests.

CHAIRWOMAN SANDOVAL: If it will choose, the applicant may make a closing argument.

MR. HNASKO: Thank you, Madam Chair. In the interest of time, I will be brief. I think it's been well covered today.

What we have established in our submittals and with what the questions have been and how we worked together with the objecting parties to satisfy concerns, and we think that the application, we are in a receptive area, our proposed interval for disposal, we are very confident in that.

I think the one thing that hasn't occurred today is emphasis on the fact that we are going to undertake a core drilling program to determine exactly what the geologic conditions are so we can verify those as we go.

We are confident that our porosity calculations look good, and even if they were at 17 percent, as opposed to 12 percent, I think we would still have a very receptive area for the disposal of this TAG.

So all things considered, we think that, rather than going through the Devonian, our intention was simply to find the best location, whether it be the Devonian or

Delaware Mountain Group. That's how we started. We started with a blank slate, the idea being we are not going to have a preferential predisposition for one place or the other, but let the geology tell us.

In this instance we felt that we had sufficient, more than adequate protection, both above and below the disposal zone such that we had impermeable rock layers that would protect the Capitan Reef. We don't think we are in the reef, but in any event, we will have sufficient protection below and above to ensure that we contain the TAG in the manner represented.

We felt that because of the absence of production in this area, the well to the east that we spoke about watered out quickly. There is no production in any close interval, so we were satisfied there.

We felt that the sandy nature of the permeability aspect of this area really made it the ideal receptor for this TAG, so we went there. And when we got there, we found out the generalized objections as we have seen in the OCD Exhibit 2, and we understand that, and appreciate that.

But there have been some issues. On the hand you can say there's generalized issues. Does that mean that disposal in the Delaware is always inappropriate? You can't say that. Not sure if you can say it's always appropriate. It should be based on the facts of the particular application.

But nonetheless we understand that, and the last thing we want to do is affect correlative rights or create waste or cause harm to human health or environment.

So we reached out after the objections were filed with both the State Land Office and the OCD. I must say we had very productive conversations with the OCD, and they listened, and we listened and came to an arrangement without much haggling. Because we knew that if that's the result they want, we accept that, and we appreciate that, and we want to participate in that as a good corporate citizen.

So we are going to go forward with these special conditions and submit our application for the redundant well as soon as possible, and transfer our primary disposal operations to that well and use this as a redundant well.

The OCD will, because it's AGI, they will receive quarterly reports on what is being disposed of, and certainly we have a good working relationship at all times and would inform them of our intentions without simply doing it.

So we will monitor this very closely. We think there is very little chance of affecting any correlative rights, and certainly of anything of that nature and fresh ground water sources or anything else or in the Capitan Reef, we want to be fully protective of that.

From a human health and environment standpoint, this is the ideal solution. And it's unfortunate this is -- we don't have a perfect solution for the disposal of oil field waste. We have to do the best we can with the data we have, and under these circumstances, the handling of H2S is extremely dangerous. It can be. If it actually happens, it's unforgiving, as Mr. Perilloux said, totally unforgiving. So we want to make sure we are doing that in the most environmentally sensitive and beneficial way we can.

The added benefit here is the sequestration of CO2. We are very proud of that, because that's going to go a long way to helping with our environment. So I think -- I think you got the impression from Mr. Perilloux, I could certainly vouch for him, but I don't think I need to, he knows exactly what he is doing in this company. And they are a very sound operator, and they take it very seriously.

And their commitment to New Mexico has been shown. Their commitment to human health and environment has been shown, and they basically agreed to all conditions that are reasonable -- reasonably imposed on them.

We have had no issue at all with the State Land Office. We thought they raised some very good points. We have no issue at all with the OCD. I think we might have met with them two or three times, and we resolved everything. And that's the way we are going to go forward here.

And we know there is a preference not to be here, I get that, in Delaware, but under these circumstances the data established that we should be here. But regardless, because we know there is uncertainty, the conditions will take care of any concerns that we have.

So with that, Commissioners, we respectfully request that you grant the permit application and issue the permit with the conditions agreed to by the parties.

CHAIRWOMAN SANDOVAL: Thank you. If it wishes, the Land Office may now make a closing argument.

MS. ANTILLON: I would just reiterate what I had presented during my opening statement, that we would ask that the Commission accept the application, but subject to those special conditions that we had agreed to.

CHAIRWOMAN SANDOVAL: The Division may now make a closing argument if it wishes.

MR. AMES: The only thing I would add, Madam Chair, we second what the State Land Office just said, I think that's clear from our testimony. Mr. Goetze made clear his concerns of OCD regarding potential impacts of DMG wells and correlative rights and on public health, environment, the possibility of waste.

And he also made clear in his testimony that we believe these conditions will adequately address those concerns and ensure that OCD and the OCC complies with its statutory obligations. Thank you.

CHAIRWOMAN SANDOVAL: The record of this application hearing is now closed. The Commission will immediately deliberate to reach a financial decision on the application pursuant to the Administrative Adjudicatory Deliberations Exception, the Open Meetings Act, Section 10-15-1(H)3, the Commission may deliberate in closed session.

I will entertain a motion to go into closed session.

COMMISSIONER ENGLER: I move the meeting closed pursuant to the Administrative Adjudicatory Deliberations Exceptions to the Open Meetings Act, Section 10-15-1(H)3 to deliberate Case Number 20405.

MR. LOZANO: Actually, 20780.

COMMISSIONER ENGLER: I read it as it was written.

CHAIRWOMAN SANDOVAL: May I have roll call?

COMMISSIONER ENGLER: Take a second.

CHAIRWOMAN SANDOVAL: May I have a second to the motion to go into --

COMMISSIONER KHALSA: Second.

CHAIRWOMAN SANDOVAL: May I have a roll call?

MS. DAVIDSON: Chair Sandoval?

CHAIRWOMAN SANDOVAL: Yes.

MS. DAVIDSON: Commissioner Engler?

COMMISSIONER ENGLER: Yes.

MS. DAVIDSON: Commissioner Khalsa?

COMMISSIONER KHALSA: Yes.

CHAIRWOMAN SANDOVAL: We will now go into closed session at 2:23.

(Commission in closed session.)

CHAIRWOMAN SANDOVAL: The Commission is back in open session and on the record. The current time is 3:26.

Let the record show that the matters discussed during the closed session were limited only to those specified in the motion for closure and that no votes or official actions were taken.

I will entertain a motion to adopt the proposed order as amended during closed session.

COMMISSIONER ENGLER: Madam Chair, I move that we approve the C-108 application submitted by Salt Creek Midstream LLC for construction and use of the AGI well described in the application under the special conditions stated in the applicant's Exhibit 2 with the following amendments:

Under special conditions 1 through 4 shall be stated as written.

5A and C shall also be stated as written.

Under 5D shall be added stating, once the Devonian well commences injection, SCM will notify in writing the Engineering Bureau of the OCD when primary injection is transferred between the Devonian and DMG well.

Also under special condition 6 and 7 they also shall stay as written.

Under standard conditions, Number 1, we shall require an MIT annually, conditioned to the word annually.

2 through 7 shall be stated as written.

Number 8 shall require that the biocide component include biocide corrosion inhibiting diesel.

9 through 10 shall be stated as written.

Under Number 11 shall also state that the plan shall include a contingency plan for impacted gathering lines with a GIS mapping layer also subject to OCD approval.

It shall also be stated that operator will also prepare a response plan if the DMG well is temporarily inactive for any period prior to the Devonian well commencing injection. This response plan is subject to OCD's approval.

12 shall stay as written.

13 shall state that operators shall also submit core data if applicable.

14 and 15 stay the same as written.

Number 16 shall be amended to require reporting after the fifth year of injection. Reports shall include seismic model and an in-person presentation of the report shall be provided to the Commission at its request.

The following additional conditions shall be included:

In the event SCM transfers ownership of the well, SCM shall seek approval of such change in ownership from the Division pursuant to 19.15.9.9 NMAC.

Number 2, after 30 years from the date of the Commission's order in this case, the authority granted by the order shall terminate unless applicant or its successor in interest shall make application before the Commission for extension and authority to inject.

And the last quick item for the purpose of all the proposed order, any reference to the OCD in these conditions shall refer to the OCD Engineering Bureau here in Santa Fe.

That's it.

CHAIRWOMAN SANDOVAL: Can I have a roll call vote -- oh, can I have a second to --

COMMISSIONER ENGLER: Approve the --

CHAIRWOMAN SANDOVAL: -- approve the motion? Do I have a second?

MS. DAVIDSON: Do you have a second?

CHAIRWOMAN SANDOVAL: Is there a second to approve the amendment?

COMMISSIONER KHALSA: Yes.

CHAIRWOMAN SANDOVAL: Can I have a roll call vote, please?

MS. DAVIDSON: Chair Sandoval?

CHAIRWOMAN SANDOVAL: I approve the amendment.

MS. DAVIDSON: Commissioner Engler?

COMMISSIONER ENGLER: I approve.

MS. DAVIDSON: Commissioner Khalsa?

COMMISSIONER KHALSA: I approve.

CHAIRWOMAN SANDOVAL: Thank you.

MR. LOZANO: Just a couple of things. I think first for the OCD, just for future purposes, the changes that we made to the standard conditions, the OCD should expect that those will be added to the standard conditions in the future, so just for your knowledge.

And then I think the professor wanted to make a statement with regard to the information that was provided today.

COMMISSIONER ENGLER: Oh, yeah. We have had a really good discussion on certain items in terms of data, some uncertainty analysis, and what I would like to see is to at least have that included in any subsequent type of actions or requests in terms of AGI.

I think we are all on board that we do have a lot of uncertainty, so for me I would like to see a little more of that fleshed out in any of the presentations.

For me, that's just -- I want to give you like a heads-up, you know, you have heard me say this, I would like to have that, kind of a better description of some of these in the future. That's it.

CHAIRWOMAN SANDOVAL: All right. We will move on to -- oh, gosh, yeah, I forgot about that part.

Counsel, please draft an order for the committee to review at the January 16 hearing in 2020.

Now we will move on to Item Number 6.

(Agenda Item 5, Case Number 20780 concluded at. 3:28 p.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

REPORTER'S CERTIFICATE

I, IRENE DELGADO, New Mexico Certified Court Reporter, CCR 253, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

I FURTHER CERTIFY that I am neither employed by nor related to any of the parties of attorneys in this case and that I have no interest in the final disposition of this case.

Dated this 11th day of December 2019.

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