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

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

APPLICATION OF 3BEAR FIELD SERVICES, LLC FOR AUTHORITY TO INJECT, LEA COUNTY, NEW MEXICO. CASE NO. 20409

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

June 6, 2019

Santa Fe, New Mexico

BEFORE: ADRIENNE SANDOVAL, CHAIRWOMAN
JORDAN KESSLER, COMMISSIONER
DR. THOMAS ENGLER, COMMISSIONER
MIGUEL LOZANO, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, June 6, 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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EXHIBITS OFFERED AND ADMITTED

(9:03 a.m.)

CHAIRWOMAN SANDOVAL: Case Number -- or Item 6 on the agenda, Case Number 20409, will now be heard.

Will counsel introduce themselves?

MS. CALLAHAN: Candace Callahan with Beatty & Wozniak appearing on behalf of 3Bear Field Services, LLC. I have two witnesses to be sworn.

MR. BROOKS: David Brooks, Energy, Minerals and Natural Resources Department, appearing for the Oil Conservation Department. We have one witness.

CHAIRWOMAN SANDOVAL: Okay. So this is a -- this hearing in Case Number 20409 is to consider the application submitted by 3Bear Field Services, LLC for authorization to inject carbon dioxide and hydrogen sulfide from its Libby Gas Plant into two offsetting gas injection wells.

The Oil Conservation, through timely notice, has intervened for the purpose of this hearing.

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

The hearing shall now proceed as follows: All testimony will be taken under oath. I will admit any relevant evidence unless I determine the evidence is unduly repetitious, otherwise unreliable or of little probative value.

Any party who wishes to make a brief opening statement before presentation of his or her direct testimony may do so. The Applicant will present direct testimony first. Other interested or intervening parties who have standing and who have filed a timely prehearing statement or notice of intent to present testimony may present direct testimony.

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

Redirect examination will be permitted, but such testimony is limited to testimony relevant to that authored during the cross-examination. 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 nontechnical testimony in the same order as the direct testimony.

Any objection concerning the conduct of today's hearing may be stated orally during the hearing with the party raising objections briefly stating the grounds for objections, rulings made on any objection, and the reason for it will be stated on the record.

We will now proceed with the hearing. Will those persons who wish to testify at this hearing on behalf of the Applicant please come forward so that the court reporter may administer the oath?

(Mr. Gutierrez and Mr. Solomon sworn.)

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

OPENING STATEMENT

MS. CALLAHAN: Thank you, Madam Chair.

We have two witnesses today, a fact witness and an expert witness who will testify as to the technical aspects of the C-108 application that is the subject of this case.

The first witness is Mr. Michael Solomon, who is here representing 3Bear Field Services, LLC. He will briefly introduce 3Bear Field Services to the Commission and provide background to the Libby Gas Plant. He'll discuss the Libby Gas Plant's operations, its proposed expansion, and he'll let us know how the plant relates to the two proposed acid-gas wells.

Mr. Solomon will testify regarding the important environmental and economic benefits of both the plants and the two acid-gas wells, and he'll also explain why the proposed acid-gas wells are an integral part of the Libby Plant.

Our second witness will be Mr. Alberto Gutierrez of Geolex, Inc. He will provide technical and expert testimony supporting the C-108 application. And ultimately he will show that the C-108 as proposed is approvable, the groundwater resources will be protected, human health and environment will be protected by reducing emissions, and the proposed injection wells will prevent waste and protect the correlative rights of adjacent producers.

At this time I would call my first witness.

MICHAEL SOLOMON,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MS. CALLAHAN:

Q. Good morning, Mr. Solomon.

A. Good morning.

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

A. Michael Solomon.

Q. And where do you reside?
A. Denver, Colorado.
Q. And by whom are you employed and in what capacity?
A. 3Bear Energy. I'm the vice president of engineering and operations.
Q. And how long have you worked for 3Bear?
A. I've worked for 3Bear for a little under two years.
Q. And what are your responsibilities as senior VP?
A. So I manage our engineering team, our operations team and construction team for our Northern Delaware Basin asset.
Q. And are you familiar with the application that's been filed in this case?
A. Yes, I am.
Q. And although you are an engineer, today you're testifying as a fact witness; is that correct?
A. That's correct.
Q. Okay. And Mr. Gutierrez will provide the technical expertise supporting the C-108?
A. That's correct.
Q. But you are familiar nevertheless with the C-108 application; are you not?

A. Yes, I am.

Q. In the notebook that we've provided, the dark one is the one that has all the updated exhibits. I think you disregard the white notebook.

If we look at page 4 of Exhibit 3, Mr. Solomon, briefly would you give us some background information on 3Bear Field Services?

A. So 3Bear was founded by Bob Clark in 2013. Bob has been in the industry in a variety of roles for about 50 years. The management and technical team that Bob assembled also has significant experience building, constructing and operating these assets in a variety of basins. So, you know, we have -- we've constructed and operated in the Bakken, Rockies and the Permian Basin, and now we're moving into the Northern Delaware as well.

We are backed by GSO Capital. GSO is the credit arm of Blackstone. So GSO, in particular, has around 86 billion assets under management. At the time of pulling these numbers, which was probably about a year ago, they had 5.2 billion just in dedicated energy funds. That number I think has gone up significantly since then, but it gives you an idea of how we're capitalized.

We're obviously a midstream company. You know, we say that we provide a four-stream solution.

So, of course, gas-gathering processing, that's what we're talking about today. Oil gathering, we have a fairly large -- a growing terminal in Lea County as well, and then water gathering, disposal and recycling. So we consider recycling to be that fourth stream that we offer. And we're seeing growing demand for water recycling by the -- by the week.

I put some of the producers up here that we -- that we serve, some of our customers, just to give you guys an idea of who we work with. But we have roughly 15 customers, large companies and small.

Q. Let's look at pages 5 and 6 of Exhibit 3. And, Mr. Solomon, would you discuss the Libby Gas Processing Plant for us, please?

A. Uh-huh. So we entered New Mexico in about September of 2017. At that time we were still in the design phase -- design and permitting phase of the gas plant. We started construction in January and February of '18, and we were in service by September.

At the time of putting this presentation together, we had 19 full-time employees in New Mexico. We are up to 22 right now and continuing to hire. Honestly, I can see us hiring another five to seven this year. It'll be 30 by year-end. That includes our water and oil operations as well. I'd consider about 35, 40 percent of that staff is just dedicated to the gas plant in field gathering.

We have -- regarding our gathering, we have roughly 45 miles of HDPE pipe for low-pressure gathering, where we gather central compressor stations. Our high-pressure gathering, we have 24 miles roughly in the ground of 8-inch steel. It's all built to NACE sour gas specs anticipating this eventual transition. Everything is connected via SCADA to a central control room at our Libby Gas Plant. We have three compressor stations all located on fee land that feed our gas plant. They all have gas drive recips with dehydration installed for water removal.

And then our central -- central gas plant is a 60-million-a-day cryo with refrigeration assist. We made a note in here just about the reliability of that facility because near really off the bat, we were seeing 99-plus percent uptime on that particular plant, which is pretty important to us and our customers.

We have an amine unit installed there for -- that's in CO_2 removal service right now and residue gas compression.

Our sales outlets are -- residue gas is sold to Transwestern right now. We're in the process of adding a second outlet to NGPL. And similarly with --

with -- with NGLs, we sell to DCP-Sand Hills today and are in the process of adding a second -- second NGL outlet as well primarily for reliability.

And this (indicating) just shows you an outline of our footprint. We -- you know, we obviously have, like we talked earlier, a gas, water and oil system, so that shows all three. But you can see the three compressor stations there, the Lariat Compressor Station, the Aztec Compressor Station, the Outland Compressor Station. And then Libby Complex, that's the central processing plant.

Q. And then moving on to page 7 of Exhibit 3 for reference, would you give us a summary of 3Bear's proposed expansion of the plant?

A. Yes. We've had a tremendous amount of interest from our customers for sour gas solution. So they would like to develop with sour zones underneath our footprint but are unable to right now because they do not have a home for the sour gas. So, I mean, frankly, we are getting calls weekly from producers, you know, that would like to do this and are asking us for a solution.

So our proposed project would be, obviously, to install the pipe to all these new receipt points. They would all be designed for sour service. We would install new compressor stations and potentially modify existing compressor stations to meet, you know, the requirements of this type of gas. So that means all the pipe meets NACE, NACE sour gas specs. All the compression is designed for what's called the Ariel Sour Level 2 specs.

And then we would also install a second plant at our central facility. Like I said, currently, we have a 60. We would install a 200-million-a-day cryo alongside of it, which would bear a total processing capacity there up to 260 million, an additional amine plant, additional compression, dehy and sour water treating and then, of course, all the safety systems that go along with converting these two style plants, so H2S monitors, horns, strobes, air packs, operator training. Right?

Q. All right. With reference to page 8 of Exhibit 3, can you give us the environmental and economic benefits of the Libby Plant?

A. Yeah. Yes. I think there are a couple of environmental -- environmental benefits. Obviously, one is, you know, with our reliability and, you know, the way we build these facilities, we -- you know, we prevent flaring at the wellhead. I think that's probably one of the biggest things. It just allowing these producers to drill and develop the resource with no flaring. So we're able to process it and get the gas to market.

Additionally with this AGI expansion, permit sequestration of the greenhouse gases, so rather than combusting the H2S and producing CO2 and emitting it, we're injecting it downhole. The CO2, you know, will be removed from the gas that's being injected downhole.

From an economic perspective, we would create a significant amount of construction jobs for the duration of this project. I would anticipate a few hundred at least per year while we build out our gathering network and surface facilities, and then we would add, of course, permanent jobs for the plant as well to support it. And then obviously one of the biggest things is the increased oil needs to the state and federal government due to producers being able to develop that resource that they're not right now.

Q. And you had mentioned that you had been contacted by several producers trying to find --

A. There is a lot of interest in the Avalon.

Q. Yeah. And that would require some help from your system in terms of processing the sour gas?

A. Correct. They do not have a place to send sour gas right now.

Q. And the Avalon is --

A. It's very sour.

Q. Yes.

Okay. Looking at page 9 of Exhibit 3, can you explain how the proposed acid-gas wells relate to the Libby Gas Plant?

A. Yeah. You know, obviously, we're not able to take this gas today because we don't have these facilities in place. So these wells, the compressors that would inject downhole, would be installed on the tail end of our Libby Plant. So if those facilities were to go down, we would have to shut the plant down. So it's -- technically, it's one and the same. So that's why we're -- you know, that's why we're permitting two wells, so we have a backup. In case one goes down, if we need to do a repair on one, we have another that we could switch over to and inject into and keep our uptime up, similar with the compression.

Q. All right. And if the Commission grants 3Bear's application, when do you anticipate drilling the two acid-gas wells?

A. I think we would be injecting within two years.

Q. Okay.

MS. CALLAHAN: I have no further questions of this witness.

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

COMMISSIONER KESSLER: I do have a few questions.

CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. Good morning.

A. Good morning.

Q. Should I address questions about the gathering system to you or Mr. Gutierrez?

A. To me.

Q. Okay. I understand that the gathering system will be for sour gas; is that correct?

A. Correct.

Q. Has that been planned yet? Put together yet?

A. We have -- so the primary concern is the steel pipe for stress -- stress sulfite cracking. And so we have -- yes. I mean, all our -- any -- any fittings that we have on the gathering in the ground has been postweld heat-treated. They meet NACE specs. All the wells have had hardness testing done to them. So it is.

Q. It's already in place?

A. It is for the pipeline. Yeah. There would be -- there would be some modifications to other facilities that we would need to make, but it's all --

it's things that we're planning on doing if we make that conversion.

Q. Okay.

A. So some -- parts of the system are. Parts of the system are not.

Q. Do you know if those pipelines are buried?

A. They are, yeah. We do not have any surface gas lines.

Q. Can you discuss some of the leak detection that's associated with those pipelines?

A. Yeah. We have -- so everything is tied via SCADA to our central control room, so we get -- we get realtime flow data. We're able to do flow balancing.

Q. Do you know if any of the gathering system crosses State Trust Land?

A. Yes, it does.

Q. It does.

During the process of installing that gathering system, do you know if you've have any discussions with the State Land Office regarding modifications of those pipelines specific to sour gas?

A. We have not.

Q. Okay. Would you be willing to have those --

A. Oh, absolutely. Yeah.

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

CROSS-EXAMINATION

BY COMMISSIONER ENGLER:

Q. I have several questions just for clarification.

So right now you're using an amine unit to scrub out your CO2 --

A. Correct.

Q. -- your H2S or just --

A. Uh-huh. There is a very small amount of H2S. Our plant's permitted for up to 150 PPM right now. The Avalon is quite a bit higher than that, so we're able to take a little bit of H2S. But there's -- there is a significant amount of CO2 that we have to remove prior to the cryo and meet our inert spec on sales gas. And that gas is pulled out, and it goes to a thermal oxidizer.

Q. So it goes to a thermal oxidizer, and then -- then from there, what happens?

A. From there, it's emitted.

Q. You emit it, right?

A. Correct.

Q. And so right now -- and if it's over two years, until you get -- if you get the approval for these wells --

A. Correct.

Q. -- you're going to have to do that kind of processing really.

A. Yeah. I mean, we -- we're very limited on the amount of sour gas we can take without these wells, so we would have to live within those limitations and potentially not take the gas until --

Q. Yeah.

You know, just so I have it clearly, so right now this is what you're doing, but obviously this injection would be able to allow you to take that extra H2S but also to have a way or means, instead of venting off, particularly the CO2, to put it underground, correct?

A. Correct.

Q. Thank you.

CROSS-EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. So would the expansion of the gas plant go in parallel with the development of these wells?

A. Absolutely. Yeah.

Q. So the intent is to do them at the same time, and then once the plant has been upgraded or like added capacity, then you would bring the wells online?

A. Well, we -- we're not drilling the wells, so, I mean, we have limited control over what the other producers that are drilling them do. But yeah. I mean, as soon as -- when we have contracts in place that are signed -- that's where we're going -- I mean, we're going to start -- start building the facilities, we'll drill the wells, and then I think they would -- I would anticipate that they would time the drilling of those wells with when our facilities are going to be in service. That's what I would think they would do.

Q. So I was referring to the injection wells.

A. Yeah. So the lead time on building the facilities is -- from start to finish, it can be 14, 16 months. For the wells, I mean, we have -- ordering all the downhole equipment can be five months, plus a couple of months for drilling, so we would work them in parallel.

Q. Do you have -- would you be putting contingency plans in place for the H2S?

A. Yeah. And Alberto is prepared to address that. Yeah.

Q. Okay.

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

MR. BROOKS: No.

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

MS. CALLAHAN: No.

CHAIRWOMAN SANDOVAL: Does the Applicant have any additional witnesses?

MS. CALLAHAN: Yes, I do.

And I would just, for the record, like to ask that we tender the portion of Exhibit 3 that we just went through for introduction into the record at the end of testimony for Mr. Gutierrez.

CHAIRWOMAN SANDOVAL: Okay. Any objection?

MR. BROOKS: No objection.

CHAIRWOMAN SANDOVAL: Okay.

(3Bear Field Services, LLC Exhibit Number 3, pages 4 through 9, is offered into evidence.)

MS. CALLAHAN: Mr. Solomon, you can take your seat.

MR. LOZANO: Excuse me, Counsel. What pages were for that particular portion? 3 through 10?

THE WITNESS: 3 through 9.

MS. CALLAHAN: Actually, it's 4 through 9.

MR. LOZANO: Thank you.

MS. CALLAHAN: Oh, maybe it was -- yeah, 4 through 9.

ALBERTO A. GUTIERREZ,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MS. CALLAHAN:

Q. Good morning, Mr. Gutierrez.

A. Good morning.

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

A. Alberto A. Gutierrez.

Q. And where do you reside?

A. I live in Albuquerque.

Q. And by whom are you employed and in what capacity?

A. I am the president of Geolex, Incorporated.

Q. And what services does Geolex provide?

A. We're a geological and engineering consulting firm with a special expertise in acid-gas injection and groundwater contamination.

Q. Have you previously testified before the Commission or the Division?

A. Yes, I have.

Q. And were you qualified as an expert at that point?

A. Yes. I've been qualified as an expert in petroleum geology, hydrogeology and acid-gas injection.

Q. And groundwater contamination?

A. That's correct.

Q. Did you prepare or oversee the preparation of and submission of the C-108 application and the induced seismicity analysis filed in this case?

A. Yes.

Q. And that was done in conjunction with Mr. Solomon or 3Bear Field Services?

A. 3Bear Field Services retained us to prepare this application and to do the geologic and engineering work necessary to find an adequate location for acid-gas injection and to design the wells and permit them, and that's what we have done for 3Bear.

Q. And the exhibits we're looking at today have been prepared by you and your staff in conjunction with representation of 3Bear Field Services?

A. That is correct.

MS. CALLAHAN: Madam Chair, I'd like to tender Mr. Gutierrez as an expert in petroleum geology, acid-gas injection operation and design, hydrology and groundwater contamination.

CHAIRWOMAN SANDOVAL: Any objections?

Okay. We recognize him as an expert in these fields.

MS. CALLAHAN: Thank you.

Since the acid-gas injection applications are not as common as other types of cases, Mr. Gutierrez included a primer on acid-gas injection as it relates to oil and gas development in New Mexico, and it's found in your materials as Exhibit 6.

With the hope that it's not too fundamental, Mr. Gutierrez is prepared to briefly run through this primer before beginning his technical testimony, if that's desirable.

CHAIRWOMAN SANDOVAL: Yes.

Q. (BY MS. CALLAHAN) Mr. Gutierrez, would you briefly go through Exhibit 6?

A. Sure. I won't read it, but I just will summarize. The purpose of this exhibit was just to prevent -- present in a very concise manner what acid-gas injection is about and why it's needed and how it's been used in New Mexico.

Acid-gas injection, unfortunately it has a name that's very scary to a lot of people, right? But it basically is simply the injection of a gas, that when it comes in contact with water, creates an acid. So CO2 is an acid gas even though we drink it every day in Perrier or club soda or whatever. It is an acidic solution when it comes in contact with water.

Similarly, H2S does the same thing. However, the significant difference is that H2S is a poisonous gas, and it is a gas that cannot be emitted to the atmosphere.

Currently, as Mr. Solomon testified, the Libby Gas Plant is producing and processing gas that has CO2 in it, a significant amount of CO2, and a very, very small amount of H2S. With that very small amount of H2S, they're able to use a thermal oxidizer and in effect burn the H2S, which converts it to SO2 and CO2 and water and that then is discharged to the atmosphere. Similarly, all of the CO2 removed from the gas is currently discharged to the atmosphere. Acid-gas injection, instead of doing that process, just takes that combined stream coming out of the amine unit of CO2 and H2S, compresses it, and then injects it back into the ground where it came from.

Why is it needed in New Mexico? Because, in fact, traditionally the way sour gas has been processed -- or was processed in New Mexico and in many other places has been changing. It used to be processed by merely doing the same thing, taking an amine unit, separating out the CO2 and the H2S and then taking the H2S and making native sulfur, you know, the yellow material that we all recognize that's used for fertilizer. That is no longer really a viable process for two or three reasons.

Probably the first major reason is that there is no market for that sulfur. The sulfur that is being created today from SRU plants is being disposed of as a hazardous waste. It's a product that's produced, and then it's just disposed of because there is no market for it unless you happen to be in a facility that's maybe adjacent to a petrochemical plant that can utilize that sulfur like in the Houston ship channel area or whatever. But throughout the continental United States and Canada and throughout many places in the world, the now preferred technology for dealing with sour gas is to reinject it. So the economic driver is one.

A very important secondary driver is that people and our society in general are much more concerned about the emission of greenhouse gases. CO_2 is a greenhouse gas, and currently there are no regulations that prevent that from being emitted once it has been separated from natural gas to the atmosphere. However, it's a preferential thing from an environmental point of view if that CO_2 can be reinjected and be put back into the ground and prevent it from going to the atmosphere.

What are the economic benefits of AGI? Well, as I mentioned, one of the things is that you're not having to deal with this production of sulfur, but it allows for the development of gas resources that are sour, significantly sour. And the Permian is full of sour gas. It is produced with the oil. Unfortunately for a lot of producers, they would love to be able to produce the oil without the gas and the water, but it just doesn't work that way. When you produce the oil, you get the gas. You have to deal with it. There are other ways of dealing with it at the wellhead with H2S, but they're very expensive, and they're not that reliable.

So are there risks associated -- public health risks associated with acid-gas injection? Absolutely. There are risks associated with handling sour gas all the time regardless of whether you're injecting it back into the ground or you're processing it in an SRU. H2S is a lethal and poisonous gas, and it has to be dealt with very carefully.

One of the other things that was raised and we'll get into it a little bit later is one of the ways of dealing with that, in addition to the obvious engineering and other safety approaches, is by the development and approval of an H2S contingency plan under Rule 11 for the OCD, and that is a necessary component of all of these sour gas operations regardless of whether they include injection or not.

That plan has not been prepared for this facility yet because it is not handling sour gas, and it will be prepared. And what this Commission has done on many other previous occasions is that when they issue an order, if you issue an order to approve these wells, you make it contingent on the approval of a Rule 11 plan, which can be prepared once the facility is in a greater state of design than it is currently in terms of the sour gas portions.

What's the safety record of AGI facilities and AGI wells in New Mexico? Well, I would say that it's an excellent safety record. There have been problems associated with AGI wells in the state that have resulted in (A) plants having to be temporarily shut down until wells can be fixed or replaced, but there has never been a surface release of H2S from an AGI facility in concentrations that would create any kind of a public health hazard. If that kind of a situation were to occur, it is typically dealt with by the procedures that are approved in a Rule 11 plan.

So how many facilities are there in New Mexico? There are probably right now about 16 AGIs operating in the state, all of which my firm has permitted, every single one, with the exception of one that Marathon had at a facility back in the '90s that was permitted very early on.

And so we have worked with OCD over the last 15 years to improve how these wells are designed and operated and monitored, and currently I think we have a pretty good system of reporting and monitoring the injection parameters that provides OCD with the tools that they need to make sure that these wells are being operated safely and in the way that they are designed.

So basically that's what AGI is all about. It is essentially just a mechanism of putting the CO2 and H2S back into a permanent disposal, geologic storage where it came from.

Q. Thank you.

So let's proceed with testimony related specifically to this case.

A. Okay. And I apologize in advance for this slide which has a lot of little writing on it, but I wanted to capture all of the key aspects of the application basically on one page, and that's what I'm trying to do.

And I would also ask -- this Commission may not be familiar with it because they haven't seen me do one of these before, but Florene certainly has, and I can drone on a little bit. So if you have some questions as I'm going, please interrupt me at any time.

Anyway, with respect to the summary that we're asking for, 3Bear is wanting to drill two acid-gas injection wells to the Devonian through the Montoya interval, which includes the Fusselman and Wristen Formations at a depth of approximately 14,900 to about 16,400 feet. That is approximately the depth that we are looking at for this disposal zone.

They foresee disposing of a total of approximately 8 million cubic feet a day of a mixed acid-gas stream of CO2 and H2S with approximate concentrations of about 80/20, 80 percent CO2, 20 percent H2S. That may vary depending what wells are ultimately connected, but that's -- that's -- for planning purposes, I think that is an adequate description of what the stream will be.

The wells will be designed according to the current state of the industry in terms of AGI facilities, incorporating all NACE-approved and required metallurgy and facilities for both monitoring -- preventing corrosion and monitoring the health of the well, if you will, by monitoring the injection parameters, the annular pressures, both at the top of well and at the bottom of the well and by reporting these on a regular basis to the OCD.

In this area there is no Devonian production within about three miles of the facility. There are a few old Devonian wells in the Lea Field to the northeast, and I'll show you a little bit about that, although that is a field that never produced a lot and is kind of playing out now. But it's outside of our area of influence.

There are only two wells that penetrate the injection zone within the one-mile area of review. One is a plugged Devonian dry hole, which we have evaluated and presented in the C-108, that is properly plugged and abandoned so that the injection zones are isolated and can't cause a conduit for gas to escape that zone. And the other is the 3Bear's own saltwater disposal well, which is located about half a mile to the northeast.

The proposed injection zone we believe is fully capable of permanently containing the injected fluid and that it has a very good caprock above and below it. And we will use the appropriate materials and procedures in drilling and completing the well to prevent the migration of fluid outside of the injection zone.

One other thing which I will mention that's important to recognize is that this gas is not being injected as a gas. We are compressing it at the surface to a super-critical fluid, and then it's being injected as a fluid.

So what are some of the key elements of this C-108? One is that -- obviously, we've talked about the CO_2 injection and sequestration which provides an environmental benefit of reducing greenhouse gas emissions. It also reduces waste and air emissions by eliminating the flaring of acid gas and the SRU and thermal oxidizer as is currently being used, which creates additional air quality contaminants that have to be regulated by the air permits.

Nearby oil and gas wells and nearby water wells and surface water will all be protected by both the well design, as well as the geology of the area.

The application that we have prepared and that has been submitted to the OCD includes all of the information necessary to approve these AGI wells. There was a concern expressed. Initially, this hearing was set for April, and there was a concern expressed by Mr. Goetze, to us, of the Division, that there had not been a seismicity -- induced seismicity analysis done of this site. And given the fact that there are some saltwater disposal wells in close proximity, there was an interest from the Division in having that work done.

So we then postponed this hearing for two months so that work could be done. We did that work, provided the results of it to the Division approximately a month ago, met with them, and I believe that we have satisfied their concerns on that score.

The adjacent operators are -- are in the -- the OCD and the BLM are all strongly in favor of avoiding further injection into the Delaware Formation and going to a deeper Devonian reservoir, and that's why we have selected the zone that we've selected in the area. And the operators and surface owners have received proper notice. They've been individually noticed, as well as this hearing has been noticed, and there have been no objections to the AGI project. In fact, quite the opposite. The operators are ringing the phone off of Mike's desk, saying, "When can you start taking our sour gas?"

So let's talk a little bit about the application itself. The plant is located in Lea County. The next -- let's see. You can see a little bit -- this is just a large-scale map so you can get an idea of where the facility is relative to Hobbs and Lovington and Jal down here (indicating). So the facility is here (indicating), off of 128, north of the 128 here and west, southwest of Hobbs.

A little more detailed site (indicating), this shows the limits of the current 3Bear fee acreage upon which the plant is built. This is their SWD that is located to the northeast. This is where the two AGIs are currently planned, one vertical well here, AGI No. 1, and then an inclined well, AGI No. 2. And the reason for that is just so that we can keep the bottom-hole locations of the two wells separated by about 1,000 feet to prevent interference really between the injection operations.

The idea of having the two wells is simply redundancy and reliability. You can operate both of them at the same time, but they're designed to be able to take the entire design flow into one well or the other so that that increases the ability to maintain uptime for the facility as a whole.

It's about 120-acre facility. The planned operations currently occupy about 60 acres, and it will be increased as we add facilities to deal with the sour gas. Currently, as I mentioned, there is a single amine unit there. There will be another amine unit and, of course, all the surface equipment required for compression.

This is just an approximate map that shows where the facility is and kind of what the layout of it would be, and the line going out to AGI No. 1 and AGI No. 2 would be coming from here, from the compression facility, and the amine units straight out to the two acid-gas wells. This is also located on 3Bear land. This is only showing the current footprint of the plant, but as you saw in the other one, the footprint of their land goes on out here (indicating).

Q. Just for clarification, Mr. Gutierrez, I want to ask you whether 3Bear owns the surface.

A. That is correct.

Q. And it's federal minerals; is that correct?

A. That's correct.

CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. Mr. Gutierrez, if I could just ask a quick question. I think a couple of slides back you talk about the -- you have a high-level summary saying -- discussing the radius of influence for 30 years. What is the anticipated life of these wells?

A. Well, what we use as a planning life is 30 years. The wells could, theoretically, last longer than that, but as a planning horizon, that is what is typically used.

Q. Okay.

A. Okay. So what are we going to put in the wells? I said approximately 8 million cubic feet. That's what we're asking for as an upper limit, of about 80/20 percent CO_2/H_2S. Inevitably, amine units, even if operated very well, have some residual hydrocarbons that get entrained in the stream. So we might have as much as a percent or half a percent of C1 through C8 hydrocarbons that go along with that stream.

The capability of that fluid has been pretty well established by operations of similar AGIs in the Devonian over the past 20 -- or at least -- yeah, 20 years in the basin there.

The MAOP that we're requesting has been calculated per the NMOCD guidelines to be about 4,500 psi at the surface. However, our experience with similar wells in the area indicates that for the kind of volumes that we're talking about, we should be able to put that gas away at about 1,400 to 1,600 psi at the surface. And that depends on the temperature, but it's approximately that.

We then wanted to do a calculation of what -- how much volume this is going to use up, if you will, of the reservoir and to try to model what the size of the plume would be, and that has been carried out in the application. And those calculations are shown on Table 1, and I'll show you that in just a moment. And the results of that indicate that if we operate the wells for a full 30 years at the full 8 million a day, we would wind up with a plume of acid gas of approximately four-tenths of a mile, .38 miles, from the bottom of the well.

Now, exactly how that plume is going to look is a little difficult to predict based on how you inject into each well or whether you inject into both of them at the same time. But, frankly, if we were injecting into both of the wells at the same time, we probably might end up seeing a little more of an oblong plume but probably one that would be about the same actual area covered.

So let's take a look -- one of the things that -- that is important is to show that when we calculated this -- by the way, this is the calculation (indicating). And it shows some interesting things. At least they're interesting to me. So I'll point them out, and that is that at the surface, if you're injecting at about, let's say, 90 degrees, 1,800 pounds at the surface, what you see at the surface in terms of volume is something like 19,000 cubic feet or about 1,300 barrels of fluid. However, because at the bottom of the well you have a significantly higher bottom-hole pressure, a higher temperature, you end up actually taking up a little bit more space in the reservoir than what you actually have in the bottom of the well because the temperature primarily affects that, and the temperature in that reservoir is about 210 degrees.

So with that information, we calculate the approximate acreage that would be involved in injection after 30 years. And when you calculate the radius, it is approximately 2,000 feet or .38 miles. And, likewise, using this formula, which is the standard OCD formula for calculating the MAOP, that is how we came up with the 4,525 pounds of MAOP.

This map shows a couple of things. It shows a one-mile radius, and you can see quite a few wells in that one-mile area. Most of those wells do not penetrate the Devonian. Only two do currently. One is that plugged well that I mentioned, and the other is the saltwater well that 3Bear currently operates.

Here are the two wells (indicating). And essentially what's very important is that in this simulation that we did, we estimated what the plume would look like if you injected essentially twice our requested volume, because here we put 8 million into each one of these two wells. So actually, if you only put 8 million between the two wells, these plumes would be significantly smaller. But we do that in order to accomplish the objective of having some kind of a safety margin in the modeling, because the radial modeling of the plumes is only an approximation since there are features in the reservoir that really determine exactly what the end look of this plume is going to be after 30 years. And, again, this is important to note that in effect you're showing what it would look like if we put 16 million a day for 30 years rather than 8.

COMMISSIONER ENGLER: Let me interrupt because I have some questions, Mr. Gutierrez.

THE WITNESS: Sure.

CROSS-EXAMINATION

BY COMMISSIONER ENGLER:

Q. Let me start with -- in your report, you mentioned about running an FMI log and some core.

A. Yes, sir.

Q. Tell me -- first of all, tell me, from the FMI, what do you hope to gain from that?

A. Sure. The FMI is a very useful tool. We've been using it for about 15 years now to characterize the degree of either fracturing or secondary porosity and the orientation of those fractures in the borehole. So the FMI actually allows you to identify both the orientation and the presence of fractures both induced by the drilling as opposed to separately existing in the reservoir itself.

Q. Is there an FMI on the saltwater disposal well? Do you know?

A. I do not believe there is.

Q. So yeah. As you point out, you're looking at -- looking at secondary porosity and direction.

A. Right.

Q. So in your experience in other FMIs, have you seen that kind of directional permeability or directional -- I guess permeability in any other wells?

A. We have seen some indications of kind of consistent stress directions and fracturing in the FMIs, and we try to use that in our -- when we bring together all the data from the well when we complete it, and we then relook at these models to see how they might change. And as a matter of fact, as the Division can affirm, when we provide the Division -- even though it's not required, we provide them a comprehensive end-of-well report that shows all of the FMI logs, all the core testing, if we do cores, the step-rate testing, which we do on the wells, and the analysis of that to better try and understand what the reservoir looks like.

Q. Because in your description here, you're just dealing with purely isotropic permeability there for your circle?

A. That's correct.

Q. And yet -- you know, I applaud having this -- having this FMI and core data for geologic -- I guess 3Bear is paying for it.

A. Right.

Q. I applaud that, but I don't see it in any -- your work here is purely circular isotropic?

A. That's right, because there really is no ability to do anything more at this point. I mean, there is no -- if you can imagine, there are only two wells even within a one-mile radius that even penetrate the zone. So we really have no ability to do, you know, a comprehensive reservoir model or anything that would better represent that.

Q. There is regional work in that area in terms of directions of -- for different formations of, again, your anisotropy, not specifically where you're located, and hopefully your work will provide as you get more background. But there is regional work that shows directions.

A. And, in fact, if you'll -- if you'll indulge me, as we did the work that we discussed with Mr. Goetze, we used the regional stress directions and in -- and in addition to that, we were able to approach one of the operators that is 3Bear's client, Chisholm Energy, which had 3D seismic over the area, and we reviewed and analyzed that 3D seismic. So that also gave us a better sense of those directions.

Q. Let me ask, since we're kind of on the subject. This is slightly different. When you calculate your area, you're calculating based off of a thickness that is -- your total open-hole thickness was like 1,500 feet, right, 1,500 feet thick?

A. Correct.

Q. With some average porosity, you used a 3-1/2 percent?

A. Correct.

Q. So that thickness is the total open-hole thickness. Seems to me -- or let me ask it this way. Could you kind of address in a little more detail the fact that, you know, your area is fully dependent upon that thickness and you're going to use the entire thickness of your open hole to be able to calculate that area, and that seems to me -- I'd like to hear a little more about why did you use that thickness and not something a little more detailed?

A. Well, simply because we, at the present time, don't really have the data to be able to identify what zones within that thickness are going to preferentially take the flow. That's part of why we do both the FMI log, the step-rate testing. And usually when we do that, we also do a DTS survey so that we take a look at the temperatures and understand what zones take more water than others. So clearly -- or more gas than others. Obviously, we do the step-rate testing with brine, not with acid gas.

So what we've seen from our experience on previous wells is that even though we use this kind of average porosity over the thickness of the interval, once we actually drill the well and have that data, we can come back and look at how that overall plume geometry could be affected by the zones that take more fluid than others. But you have to remember also that the zones that typically take more fluid are also significantly higher porosity. So even though they may be not as thick, they actually are having a porosity that's much greater than that 3 percent average and so consequently are able to accommodate more gas in a relatively smaller area.

Q. Well, that's true. But in your work that you present, some of your work on some of the offset logs, you identified zones of higher porosity.

A. Correct.

Q. And so to some extent, you have that -- some data that shows that part of this 1,500 feet has a

certain amount of porosity and then so you have a certain thickness porosity versus what you're using here. It would -- I guess I would suggest -- again, you're going to get more data with FMI. But most of the time in these variables in petrophysics, we do a certainty analysis with plus or minuses --

A. Right.

Q. -- see the variation of the properties. And so if I saw a variable, you know, distribution of porosities, thicknesses, then I would maybe -- you know, you could probably say, "Hey, this area is going to be within this domain and not farther out. So to me you're using a very optimistic thickness. I think you could probably use a little better data or analysis to get a more layered system of where this actually is going to go. And this is something that I've seen in past reports, too, so I was kind of wanting to get a good feel for why this -- this is a very simplistic volumetric analysis.

A. Absolutely. And I don't deny that. It's just that when you only have a density of maybe, you know, over a, like, six-square-mile area, you have like three or four wells in the -- in that zone, it is very difficult to reliably be able to identify what those variable porosity zones are.

Q. True. But one of them is your disposal well when one of them is a water well that has good data.
A. That's right.
Q. Let me ask. So you have residual water saturation. What is that?
A. That is the water -- the percentage of water in the reservoir that is immovable. In other words, so you don't -- you can't use all of the available porosity because there is some water that is trapped in the reservoir that can't be removed, and that's why we use an irreducible water.
Q. But your immovable water saturation, how did you get that?
A. The way we use that is -- the way we derive that is from looking at the logs over the area for that formation and doing the RW calculation and figuring out what is a representative value.
Q. This is the immovable water. So what's the other 34 percent?
A. Is water that is movable.
Q. And how do you differentiate that on logs?
A. I don't think you can differentiate it on the log other than by using the RW and the difference between the two curves on the resistivity log.
Q. Okay. Yeah. So you're saying you have 100

percent water. Sixty-six percent is immobile, and you're using log data characteristics to say this is immobile.

A.   That's correct.

Q.   So the other percentage is mobile water. So basically you're saying you're going to displace into?

A.   That's correct.

Q.   So how do you -- again, I don't see how you can, on logs, differentiate between mobile and immobile water?

A.   Well, you calculate the RW on the log itself, and then there is a formula -- I'd have to go back and look at what -- where we calculated that originally. And I can come back -- it may be during a break I can go back and look at it and provide it to you.

Q.   Let me ask another thing. So when you do your displacement calculations, again you're displacing purely into the acre space and to this mobile water phase that you're saying?

A.   Yes, sir.

Q.   There's been no -- no analysis how you -- soluble, say, CO2 into water or mineralization or any of that component?

A.   Not for this site specifically. But, I mean, I've actually published a number of papers, and there are -- there is a significant amount of data available as to how these plumes behave in the subsurface in various kinds of carbonate reservoirs. And what you find inevitably is that there is really no significant in -- I mean, over geologic time, there is a significant dissolution and mineralization into that reservoir, but really in the kind of time frames that we deal with injection of 30, 40 years, you're basically displacing it with a separate phase.

And that -- and where it has been actually measured or modeled -- which there are very few locations, a couple in Canada, one in Texas that I'm familiar with -- where what you actually see is a plume of acid gas that, at its boundaries, goes from essentially 100 percent acid gas filling up the available pore space to essentially zero detectability over a few hundred feet. It is a very sharp boundary, and it takes a significant amount of -- I mean, there's been a lot of geochemical modeling and stuff to look at how long it takes maybe this CO2 to become actually fixed in the formation, and, you know, the times are geologic in scale. So most of what happens in the kind of the time frame of analysis that we're looking at is a just pure displacement of that water and a creation of a -- basically a plume of acid gas.

Q. So, again, you really didn't look at solubility.

Also, you know, did you look -- CO_2 is in a super-critical phase, right?

A. That's correct.

Q. So when it's injected, it will also be a super-critical phase also?

A. That's correct.

Q. Which also has slight variation in its properties.

Did you look to see -- do you know if your temperature pressure meets super critical for your H_2S?

A. Absolutely. Absolutely.

Q. Okay. And so it also is a super-critical phase?

A. Absolutely.

Q. So that will impact -- again, you're looking at purely at displacement?

A. Right.

Q. And really there are a lot more mechanisms in this acid-gas injection that should be taken into account, I think, to see how it actually -- in your case, your radius or area of investigation hap- -- occurs. And so -- because I've done -- well, we've done a lot of work on super-critical CO_2, CO_2 displacement

and sequestration, so we have some pretty good models and ideas how this works. So there is a lot more out there, I guess is what I'm trying to say, meaning -- my point should be hopefully that just like with FMI and core data, maybe you can continue to get more data and to get better modeling to further this analysis than this very straightforward one. That would be great to me.

A. That's right.

And, obviously, as you gather data from the operation of the wells, you become better -- and from the downhole pressure and temperature changes in the well, you can better understand this over time. And as a matter of fact, I think one of the ways that the previous Commission has dealt with these uncertainties is that as -- as a requirement has been typically imposed on these AGI wells that after a period of ten years of data gathering or whatever, that we come back to the Commission with a report that compares these initial estimates to what is better defined once you have some more data to work with. And that has been -- you know, actually, I think the first one of those kind of end-year reports from a facility that we're working on is due in about two or three years, so we'll see how that plays out. But that's part of how the Commission has dealt with that uncertainty in the past.

Q. I think it's excellent to go back and have that look back to see how, you know, you can -- you know, again, either how accurate or how we would adjust based on data.

Thank you for your patience.

A. No worries. That's what I'm here for.

Okay. So let me then talk a little bit about a couple of administrative things before we go into some more technical aspects, because it's also very important, that the facility has provided and we have provided detailed individual notice to the surrounding property owners, as well as mineral lessees and surface owners. And I'd like to tell you a little bit about those notices, so I think that counsel's going to --

CONTINUED DIRECT EXAMINATION

BY MS. CALLAHAN:

Q. Ask you questions.

A. -- go through that. Yeah.

Q. Okay. So a detailed breakout of the surface and mineral ownership is included in this C-108?

A. That is correct. It's in Appendix B.

Q. All right. And it encompasses the owners within the one-mile area of review; is that right?

A. That is correct.

Q. Okay. Were there any unlocatable owners?

A. There were not any unlocatable surface owners or mineral lessees or mineral owners.

Q. All right. And all notices that you sent out were sent out by certified return receipt?

A. Yes, they were.

There was one notice that was sent out to an operator that had now, as I recall, gone into receivership, and we had to get an address for the receiver and send them the notice. So ultimately everybody got their notices.

Q. And you received the return-receipt cards for everybody?

A. We got the green cards back for all of them. Yes.

Q. All right. And the landman for 3Bear verified to you that he undertook a thorough search of the county records to ascertain who the mineral and surface owners were within this one-mile area of review; is that correct?

A. Absolutely. And they provided that certification to us.

Q. So all affected parties have received actual notice of this hearing and the application?

A. They have.

Q. And there's been no opposition to the application by anyone; is that correct?

A. That is correct, with the exception of the original concerns that the OCD had that required us to do the induced-seismicity analysis.

Q. Which you resolved; is that right?

A. Yes, we did.

Q. I think you can proceed with reviewing perhaps the optimum reservoir characteristics?

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. I have a quick question about notice. Was the BLM provided notice?

A. Yes.

Q. And no objection from them?

A. No.

Okay. So maybe some of this we've already gone over, but I'll just refresh. What are the really key things that we look for in a reservoir for acid-gas sequestration? We want a geologic seal. We want a caprock that will permanently contain that tag both on the top and bottom of the reservoir. Ideally it's more critical at the top because even in a super-critical state, this acid gas is lighter than the host fluid in the reservoir. We need it to be isolated and fully protective of any fresh groundwater. This is accomplished by an extensive series of surface intermediate casing that is cemented to the surface and isolates that water. Also, remember, fresh water in the Permian Basin, even if you take into account the red beds, which, you know, have somewhat fresh water, is only a few hundred feet depth, and we're talking about injection to approximately 15,000 to 16,000 feet.

You want a zone that's laterally extensive and permeable and has generally good porosity and has excess capacity for the injected volumes, and you want compatible fluid chemistry. And I believe that we have all of those in the Devonian at this location.

So what did we -- what process did we go through to look at the geology and to identify these things? So we looked at all of the wells within two miles and then one mile of the facility. There are 39 active wells, 29 plugged-and-abandoned wells, which are shown on Figure 5 of the application. But remember, only two of those, one of which is plugged and one of which is 3Bear's saltwater well, that actually penetrate that injection zone. There is another well that is currently being drilled that will penetrate. It's a saltwater well. And we have taken that into account in our modeling as you'll see a little bit later on.

The Arlen Edgar well is the well that is plugged, and we've provided plugging diagrams, and it's located about four-tenths of a mile south of the project.

The well designs are basically the same for both wells except one is an inclined well. And the idea is that down to about approximately 12,300 feet, the well design is identical, because we're not going to kick off on that angle until we get below the Wolfcamp, which is where they're currently exploiting horizontal wells in that area.

This is a map (indicating) that shows the two wells that penetrate the reservoir in this location. One is 3Bear's own well here, and this is the Arlen well that is plugged. You can see it's four-tenths of a mile south of our location. This (indicating) being AGI No. 1, the vertical well, AGI No. 2, the inclined well, showing the bottom-hole location of both wells.

Where are these wells located? The wells are basically located on the margin of the Northwest Shelf in terms of the larger structural features in the Permian Basin. They are overlain by the Woodford Shale and very tight Mississippian rocks that are shown in this area here (indicating), and those are very tight shale, Woodford Shale, very tight. And then these limestones are very -- you can see that they're quite tight, and then we've got some more shales and sandstones above that in the Mississippian before you get into the lower portions of the -- of the Pennsylvanian.

And in terms of -- this is a broken-up stratigraphy (indicating) of a well in that area that is the -- a good type well and shows the whole section. And you can see. Here in blue is our injection zone in the Devonian-Silurian into the top of the Montoya. And I will mention that, you know, we have completed numerous wells in this zone (indicating) and have a long history of using it as an acid-gas injection reservoir, the oldest of which is the Duke Energy Federal -- the Duke Energy Field Services No. 1 well, which I call it the Artesia AGI well for the DCP plant. That's been operating since 2000. And then we also have a nearby one operating at the Zia Plant where we also got good FMI data from.

These stars on here (indicating) show the zones that are either productive or potentially productive in the area currently.

What is the structure of the proposed injection area? Well, it's kind of boring, for the most part. In the -- on the top of the Devonian, you come off a nose that is a structure here in the northeast, and this is where the Lea Field is located, up in here (indicating). You can see there is very few wells that actually penetrate the Devonian in the area, but we've used those for this cross section to show you a little bit about the structure.

This is a cross section, that cross section B1 to B1 prime, and you can see there is some real differentiation between the porosity which you see developed. And typically what we have seen, in answer to your (indicating) question earlier in the Devonian out here, is that the top of it tends to be not very -- there may be a few zones that will take some fluid up here, but most of it is in this -- most of the porosity is in this lower portion, in the Wristen and then quite a bit of porosity in the Fusselman. And it just depends how much is developed in each of those areas both from a matrix porosity and a secondary porosity point of view. And we've got some ideas about that that we'll show you shortly here.

What are the major structural features then? Well, there is one large north-south-trending normal fault that drops to the east that makes the eastern edge of this Lea Field. It's about two miles east of the AGI wells, and it doesn't really pose any hazards to the project or affect the plume geometry. It's very far away from the plume. It's also -- it just turns out that one of our geologists that helped us do all of this -- some of this work, Lou Mazzullo, drilled two wells in that Lea Field in the 1981, '82 time frame where they actually went through that fault. And what they found is that it was pretty mineralized and sealed with a combination of anhydrite and calcite.

But anyway, this map shows that fault. It's a very large regional fault that is located to the east, and it bounds this Lea Field. Most of these wells are now plugged. There are some -- still a few small producers up here. You can see it's located about three miles to the northeast. There were -- and I'll show you this in the seismicity analysis in a moment. We mapped -- when we -- this is done without seismic. This is just done based on the knowledge of where this fault lies, based on well data in the area and structural mapping done on that basis. But as I mentioned, we had the opportunity to look at seismic in this area, and I'll go through what we found on that in just a little bit.

This, again, shows the porosity profile both above and below the top of the injection zone. It is somewhat variable. I think there is a misconception in the basin that you can drill a Devonian well anywhere and make a decent disposal well. We know that's not a fact. We know that it varies, and we do try to understand that in order to help us predict what the plume geometry is going to be over time, but we are working with limited data.

Let's talk a little bit about the general design of the AGI system. And what I will do is go through it in a couple of diagrams, and then we'll look at the detailed well design. But typically -- this is just kind of an overall block diagram that you have your compression facility, and then you have lines, high pressure -- basically a low-pressure line from your amine unit, your compression facility, then the high-pressure tag line, treated acid-gas line, coming out of the amine unit and then going typically to a T and then being able to live switch between either the AGI No. 1 or AGI No. 2.

The wells themselves, I'll go into more detail of how they're designed. But the general design includes several strings of surface intermediate and production casing that are cemented to the surface, of which the zones that are immediately above the injection zone are cemented with acid-resistant resin cements and containing 300 feet of corrosion-resistant casing and tubing in the bottom of the well. And this is significantly expensive material, but it is necessary to address the concerns of corrosivity in that zone.

So let's talk about the detailed design of AGI No. 1. And I won't go into this same level of detail for the No. 2 well, -- you have the information -- because it's pretty similar. We're going to put 20-inch conductor casing to about 300 feet. That takes us below most of the -- of the fresh water in the area or all of the fresh water in the area that we know of. And then we will run 13-3/8 surface casing to 1,950 feet. That also isolates some zones of usable but not fresh water in the area. Those will be cemented to the surface. Then we'll run 9-5/8 intermediate casing with that then cemented to the surface down to 12,300 feet to isolate all of the productive zones that are located above that depth that are the main targets of the exploration and production in the area. Then we'll run 7-inch steel production L80, LH80 casing down to 14,6 and then from 14,6 to 14,925. And, again, these are approximate numbers because we will determine exactly what those depths are when we drill the well. But that 7-inch CRA material is essentially either Sumitomo 25-35 or equivalent or 25-50 or equivalent, which is a high-nickel alloy that is specifically designed for being corrosion resistant in these kinds of environments. This stuff is pretty pricey.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER ENGLER:

Q. Can I ask a quick question just out of curiosity? Why 300 feet?

A. It's somewhat of an arbitrary number, but what our experience has shown over the last 20 years is that it's only at the basal portion of the wells where we really have a high potential for this corrosion to occur for two reasons. One is because obviously that's the most proximate zone to where you're injecting below it. But more importantly, within the well, is that what we use as a packer fluid in these wells is corrosion-inhibited diesel fuel. It's not an acquiesce packer fluid. But when you have 15,000 feet of diesel, even the best diesel that you have, winds up with maybe 1-and-a-half to 2 percent water. So what ends up over time is that that water tends to separate in that diesel column, and it resides at the bottom, and so that's why we protect that basal portion.

Q. All right. Because I was just really curious about the 300-foot. I was figuring it was maybe because of like ten joints of 30-foot that you were running through.

A. It is that in the context, but we could probably get away with 150 feet, too. But it's just, again --

Q. It's a safety precaution.

A. It's a safety precaution.

Q. Right. And that's very good. I was just really curious about the 300.

The other thing I just -- whenever you think [sic] up that nickel, make sure they don't overtorque it.

A. Oh, well, we -- not only that. Every one of those joints, we use GatorHawk, and we hydro-test every single joint as it's going in.

Q. Yeah. Yeah.

A. We don't want to have three miles of pipe in the hole and then find out we've got a leak somewhere and have to pull it all out.

Q. Well, that stuff is a little tricky to work with.

I'm sorry. Go ahead.

A. Yes. And as a matter of fact, you're absolutely right. That high-nickel alloy pipe, we have to have a special casing crew. It gets laid on wooden racks. I mean, it's like treated like jewelry, basically.

Q. It costs like jewelry.

A. Yeah.

Again, as I mentioned, the annular space adjacent to the CRA casing is cemented with WellLock, which is a very good resin-based cement that has superior resistance to acid gas. We have had good luck using it, and it gives us, actually, a better seal in many cases than a standard portland-based acid-resistant cement.

Okay. So then, of course, here is a more detailed design of the well (indicating). The conductor casing, surface casing, intermediate casing, production casing with the CRA being shown here in purple, then the tubing, also the basal portion of the tubing. The top 300 feet immediately above the packer is also CRA casing. We then have, immediately above the packer, a mandrel that provides us realtime bottom-hole temperature and pressure, and then we have a subsurface safety valve at 250 feet that provides us further protection in the event that there's a catastrophic damage to the wellhead that would not allow acid gas to come out of the tubing to the surface. And this design has been used in all of the wells -- or one variation of this design has been used in all of the wells we've done to date and has worked very well.

As a matter of fact, to give you a sense of this, this subsurface safety valve is not even a requirement in Class 6 wells, and yet we do it on a routine basis because we feel it's the right thing and the safe thing to do.

And similarly, for example, in Texas, we're not required to have bottom-hole PT measurements, but we at least strive to -- we design it that way, and our clients have generally gone with it because it allows a better monitoring of the well itself.

AGI No. 2 is the same except that we're going to kick off at 15 degrees once we get below the intermediate casing, and this zone here will be inclined to get over to the other bottom-hole location about 1,000 feet northwest. We've also done this before on other wells and have had good luck doing it.

All of the casing strings are cemented to the surface, and we use 360-degree cement bond logs for every string. The production string will be cemented above the injection zone with be acid-resistant cement. This casing and cement program is consistent with the BLM guidelines and their requirements, and we've used it on numerous wells previously.

Let's talk a little bit about groundwater conditions specifically in the area of review. There is obviously no permanent surface water bodies within a one-mile radius except if it rains really hard and then there might be some big puddles. Based on the State of New Mexico Engineer's area, we have showed where the water wells were in the area, and I don't think there were any water wells within that area. They're on the C-108. Again, though, we are so far below, and we are protecting that water with four strings of casing.

Now, we're going to talk a little bit about what happened when we submitted the application the first time, and the Division had concerns that there was no real work done to look at potential induced seismicity given the fact that we know there is one well nearby that is a saltwater well and another one coming on board. So we were tasked by the OCD to go and do this kind of an analysis, and the first thing that we did there was to try to obtain 3D seismic, and we were able to find three surveys that were licensed to Chisholm, which is one of 3Bear's clients in the area, and they generously allowed us to analyze that seismic and look at it. And so we then looked at the seismic, did a map of that. You'll see that shortly. And then we looked at a fault slip probability model using six wells in the area to look at seismicity in the area.

Here are the results of our seismic review (indicating). We clearly could see this fault very clearly in the -- in the seismic. There was another fault here that had some 200 feet or so of displacement, a very small fault kind of out of our area, but it was one that was defined that it was a fault.

Then what we saw are what -- I found it pretty funny that Steve Poe, the geophysicist for Chisholm, called and he said, "Well, you want to look around. You're going to see a lot of stab wounds in there." He called these stab wounds (laughter). And really what they are -- what we believe they are are karst features that show collapse within the Devonian. They're not really structural features because when you look at the regional structures, most of them are aligned in this kind of alignment (indicating), like you see this fault (indicating). This is a much larger fault (indicating) but still this kind of alignment. And these were all over the place in terms of their alignment.

And what we've seen in seismic -- I'll show you some -- I think I have a picture. No. Let me refer you to -- I want to show you this right now, though. I think there is a picture in our detailed seismic analysis exhibit, which is Exhibit 5. So if you don't mind, if you could turn to Exhibit 5, page 4. It's a little seismic section. This is not from this area so that our friends at Chisholm won't be concerned that it's their seismic data. This is from another area we've worked, but it shows very clearly what we were seeing in that seismic.

You see those two areas that are kind of highlighted in the little red-dotted zones where you have kind of a disturbance of the bedding? That is a -- not an uncommon feature. And we did actually about 18 miles of seismic throughout this part of the basin in different areas, and we've seen these quite persistently throughout the Devonian. And what it tends to be is, essentially, the Devonian Formation in New Mexico and in the Permian has subaerially been exposed at least three times in geologic time. So what that means is that the sea level dropped sufficiently that these rocks were exposed, and then it rained on them for a few million years, created caves, and then they were reburied and had more rock deposited on top of them. So what you see are these little collapse features. And that's what we saw throughout that area.

But what we did do -- and this feature labeled "A" right here (indicating) was also just like these. However, because it was so close to our wells, we opted in our model to call it a fault and treat it that way. So we really looked at these three faults (indicating) and what would be their effect based on the current injection rates of the Libby well that is the closest, this other Libby well, which is currently being drilled but it has not been completed yet, and we used what was its estimated volume, and then this Artesia well (indicating), which is another well that is a saltwater disposal well located to the west and this disposal well located. So we basically put all these wells into the model at their maximum pumping rate, permitted rates, and -- or their current pumping rates, and then we put our wells in at our maximum pumping rate and looked at how they would -- what would be the probability of slip on any one of those faults over a 30-year period. And this is the result of that modeling.

What you basically find is that Fault A, which is that little karst feature that is closest to us, has the greatest probability of slip over a 30-year period, and yet that probability only comes to about 11 percent. Most of these other faults, given their proximity or lack thereof from the injection zones, have a much lower probability.

Now, one of the limitations of this model is that it only looks at what is the probability of slip. It doesn't say how much they're going to slip. It's just whether or not they will slip. And yet that is the modeling that is typically used here for looking at this issue. It's been a pretty well-accepted model, and that's what we were able to do. And we provided that data, and I believe it was satisfactory to the Division.

Now we're getting to the end here. So what are the summary of the geologic -- as I think about these wells, there is basically -- or any injection well -- there are basically two main things that provide safety to those wells, right, in terms of their likelihood of contaminating, say, groundwater or other producing zones. And one of them are geologic factors that provide containment in a more areawide sense, and the other are engineering factors that are designed specific for the wells themselves. In other words, what are you doing to the wells themselves to prevent that well from being a conduit?

So let's take a look at what are the geologic factors first that assure the safety of these wells. The two wells penetrating within the injection zone are well isolated and properly protected in that zone. One is plugged and the other is the SWD well for the -- that 3Bear put in. The caprock is low porosity, impermeable rock, which is an affected barrier within the injection zone. The injection zone is vertically isolated from the adjacent production zones. The freshwater zones are isolated by conductor and surface casing. The injection pressure is way below the fracture pressure of the reservoir and the caprock. We're going to do step-rate tests to verify that the MAOP that we have proposed is a good one, although we never will get close to that MAOP. And then the proposed injection zone is fully capable of sequestering this gas without any increase of measurable risk of seismicity.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER ENGLER:

Q. If I could ask, please, just sort of go back.

A. Sure.

Q. So you have waste [sic], you said, way below your frac pressure. Do you have a rough idea of what that is for that Silurian-Devonian --

A. It's --

Q. -- or a gradient that you're using to estimate it?

A. The gradient that is used to calculate that MAOP was .2 plus .433 times the --

Q. Minus the density.

A. Yeah.
Q. That equation -- I guess just ask this. That equation comes from the NMOCD?
A. That's right.
Q. All right. I'll find out where they got that from.
A. Sure.
Q. For the frac pressure, though, I guess --
A. We haven't tried to calculate the frac pressure.
Q. Hopefully the step-rate tests will -- are going to give you something like that.
A. That's right. That's right.
Q. Because your MAOP is somewhere around -- estimated, again, from the equation of 4,000-something?
A. Right.
Q. And that's at surface --
A. Yes.
Q. -- right?
A. Yes.
Q. So, you know, that bottom-hole pressure must be 4,000-plus whatever?
A. Right now I think the bottom-hole pressure is about 6,000 pounds, what we estimate there.
Q. Well, your -- your -- your gradient times your

depth is giving you your 4,000.

A. That's right.

Q. So really your downhole -- if -- if you meet that MAOP, your downhole pressure is going to be very high.

A. 10,000, something like that. Uh-huh.

Q. Yeah. And that would probably be really close to frac pressure, if not exceeding it.

A. Right. I don't think it would be exceeding it, but, again --

Q. I think your step-rate tests are going to --

A. Yeah. The step rate -- that's why we do a step-rate test.

Q. I applaud you for that because you're going to need to know that to keep that value below that 4,000.

A. Well, let me just give you some sense of -- and I don't want to speak for 3Bear, but I can tell you from the rest of my clients, their compression is going to be near ability of --

Q. I'm just saying --

(The court reporter interrupted and requested the parties to speak one at a time.)

(Laughter.)

COMMISSIONER ENGLER: Okay. I'm sorry.

Q. (BY COMMISSIONER ENGLER) I'm just saying that typical compression is limited to about 2,500 pounds.

A. They're never going to get anywhere close to that frac pressure.

Q. Thank you.

CONTINUED DIRECT EXAMINATION

BY MS. CALLAHAN:

Q. I think you were going to talk about what 3Bear is requesting.

A. So in the end, I just want to summarize and say, "This is what we're asking for." We're asking for two wells, one vertical, one inclined that would be able to take 8 million cubic feet total between the two wells of acid gas with an MAOP of about 4,525. We'll begin drilling these as soon as we get contracts in place and within the two years like Mr. Solomon testified. We want to also make sure that in the order the Division has the flexibility to approve minor changes that don't affect the overall integrity of the program but that may be encountered when we drill in terms of, for example, where we find the actual top of the Devonian versus the 14,900 that we've estimated it at. We might end up finding it at 14,920 or 14,870. So we want to be able to address those issues administratively so we don't have to come back to the Commission.

Also, the proposed wells will enhance the reliability of the plant because it will allow them to continue to process gas and to process this sour gas. The wells will dispose of the acid gas safely. And, again, we will do an H2S Rule 11 contingency plan and work with Carl Chavez to get that plan approved. We've done 14 or 15 of those with Carl already, so we know exactly what he wants and needs. But we just don't have -- like, one of the things we need is to have a description of each of the H2S sensors and where they are located at the plant, and that's not yet designed. So as soon as that's designed, we would put that plan together and submit it to OCD for approval long before we would operate the wells. And we don't have any problem with the Commission adding a condition that that plan has to be approved by OCD prior to beginning injection.

Well, that's basically what we're asking for.

MS. CALLAHAN: I'd just like to ask Mr. Gutierrez a few conclusory questions.

Q. (BY MS. CALLAHAN) Based on your review, will the granting of 3Bear's application as submitted be for the protection of human health and the environment?

A. Yes.

Q. And will the granting of 3Bear's application also prevent waste and protect correlative rights?

A. Yes.

Q. Are you aware of any information or data that indicates that the target injection zones would not safely contain the injected treated gas?

A. No.

Q. In your opinion, is there any evidence that the proposed acid-gas injection wells at the proposed injection volumes and pressure will contribute significantly to increasing the potential for induced seismic events?

A. Absolutely not.

Q. And does 3Bear request the Commission grant the Division the discretion to allow minor changes to the proposed wells administratively?

A. Yes. We would ask for that.

Q. Were Exhibits 1 through 6 prepared by you, under your direct supervision?

A. Yes. They were prepared by myself or others on my staff with my direct supervision.

Q. Or you included perhaps business records of Geolex or 3Bear?

A. I'm sorry?

Q. Or you also included business records of Geolex

and 3Bear?

A. I'm not sure I understand the question.

Q. In the preparation of your exhibits --

A. Yes.

Q. -- did you perhaps include business records that you have --

A. Oh, absolutely. Yes. Yes. We have included a number of data that was provided us by 3Bear, as well as our own information about design of wells.

Q. Okay. So all of that was encompassed in your preparation of Exhibits 1 through 6; is that correct?

A. Yes, it was. That is correct.

Q. Okay.

MS. CALLAHAN: I move for the admission of Exhibits 1 through 6.

MR. BROOKS: No objection.

CHAIRWOMAN SANDOVAL: No objection?

MR. BROOKS: That's what I said. Yes.

CHAIRWOMAN SANDOVAL: Is there any objection to include the exhibits?

MR. LOZANO: Madam Chair, if I may.

Simply because if it bears on the rules that you tender the letters of notice, will you just lay a brief foundation on the exhibit marked as Exhibit 4?

MS. CALLAHAN: Oh, okay.

Exhibit 4 does include a copy -- a sample of the letter that was sent to all of the mineral and surface owners in this case, and it also includes a listing of all of the surface and mineral owners, as well as copies of the return-receipt cards that were received back from Geolex.

THE WITNESS: And it also includes, actually, the copy of each and every notice letter, not just the sample one.

MS. CALLAHAN: Oh, yes.

THE WITNESS: It includes each and every notice letter that was sent.

MS. CALLAHAN: That's right.

And at the very end, there is a schedule -- or a listing of the owners and the status of the return-receipt cards.

THE WITNESS: Furthermore I would add, in Appendix B of the application, all of the land information from the land company is included as an appendix.

MR. LOZANO: Nothing further, Madam Chair.

CHAIRWOMAN SANDOVAL: Are there any objections to including the exhibits.

COMMISSIONER ENGLER: No objection.

CHAIRWOMAN SANDOVAL: They can be included.

MR. LOZANO: For the record, that's 1 through 6.

(3Bear Field Services, LLC Exhibit Numbers 1 through 6 are offered and admitted into evidence.)

MS. CALLAHAN: And I have no further questions of this witness.

MR. BROOKS: I do not plan to do any cross-examination.

CHAIRWOMAN SANDOVAL: Okay. Do any of the Commissioners have questions?

COMMISSIONER ENGLER: Not from I.

COMMISSIONER KESSLER: No. I think all of mine have been addressed.

CROSS-EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. So on the contingency plan that you're going to prepare, would there be any opposition to sharing pipeline GIS coordinates of all of the lines that would have -- or that would fall under the H2S contingency plan? Would those -- would 3Bear be willing to provide those to the OCD?

A. I guess that would be a better question asked of Mr. Solomon than myself. But I will just say that in general, the Rule 11 plans that we have prepared previously basically are related to the operation of that facility and the associated injection wells, and so we usually start at the inlet to the facility. But, you know, that would be a question for Mr. Solomon.

Q. So, I mean, are the pipelines not included in that contingency plan?

A. They typically are not included in that contingency plan. There may be a contingency plan for those pipelines. It's a separate one. But they're typically -- it's more related to the operation of the facility itself.

Q. Okay. I mean, but essentially doing this project and approving this acid-gas injection well would mean that you're going to be gathering more, like, high-H2S gas, correct?

A. Yes. That's correct.

Q. So, I mean, I think not only would a contingency plan have to be submitted for the actual facility itself, but a second contingency plan would need to be submitted for the pipelines, and those wouldn't be brought in unless we were talking about this injection plan today; is that correct?

CONTINUED DIRECT EXAMINATION

BY MS. CALLAHAN:

Q. Mr. Gutierrez, are those not the subject of a

different type of application?

A. I believe that they are. Again, I don't deal with the gathering systems myself. I usually just deal with the facilities and the -- and if you'll look at all of the currently approved Rule 11 plans for other facilities, they're basically for the facility alone. Now, they may have a map associated with them that would show where the gathering system is, and I don't think there would be a problem with doing that.

CONTINUED CROSS-EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. Yeah. I mean, I think because we're approving -- if we were to prove that injection well, right, the gathering system would go to a more high H2S?

A. Correct.

Q. So I think within that contingency plan, that information would be imperative even for the facility where it gathers from because how -- if there is a line strike on a line now that has high H2S, how are you supposed to identify quickly -- yeah, I know there are pipeline markers, but that's sometimes miles down the road, and emergency responders don't know where those are, and OCD gets a call. So there needs to be the ability to very quickly identify whose lines those are so they can be shut in very quickly. And the reason I'm

bringing those gathering lines up is because essentially you're not going to be gathering high H2S gas unless your disapproval -- there is disapproval.

MS. CALLAHAN: Madam Chair, I think perhaps those questions might be posed better to Mr. Solomon, who has more experience and knowledge about what you're talking about.

MR. LOZANO: That's fine.

CHAIRWOMAN SANDOVAL: Okay. Mr. Solomon, can you answer?

MR. SOLOMON: Some of the confusion may be just that those pipelines don't necessarily relate to this Rule 11 plan, but I think that we are more than open, you know, in identifying which lines are going to be sour as a result of this.

CHAIRWOMAN SANDOVAL: Okay. Yeah. I mean, that would be helpful, and I think it would be necessary for this, because if we're going to approve this injection well, again, that, like, has a ripple effect all the way down through your operations, and we need to have the ability to quickly recognize whose pipelines those are.

MR. SOLOMON: Yeah. We can identify the sour lines.

THE WITNESS: So are you requesting

basically that that Rule 11 plan contain a map showing the location of those sour gas lines?

CHAIRWOMAN SANDOVAL: Not just a map but GIS information regarding that.

THE WITNESS: Yeah. I don't think there would be any problem with that.

MR. SOLOMON: Agreed.

MR. LOZANO: Are there any more questions of this witness?

CHAIRWOMAN SANDOVAL: Are there any other questions?

MS. CALLAHAN: Well, I just want to offer to prepare a draft order for the review of the Commission, if that's something that you'd like us to do.

MR. LOZANO: Once the Commission deliberates, we will direct that, Counsel.

MS. CALLAHAN: Okay. Thank you.

CHAIRWOMAN SANDOVAL: If there are no more questions, the witness can be excused.

THE WITNESS: Thank you.

CHAIRWOMAN SANDOVAL: And let's go into a ten-minute break.

(Recess, 10:56 a.m. to 11:12 a.m.)

CHAIRWOMAN SANDOVAL: Okay. Let's go back on the record.

Division, would you like to proceed?

MR. BROOKS: I would like to proceed, Madam Chair.

Madam Chair, Honorable Commissioners, we are not here to oppose this application. We are here to be of any assistance to the Commission if we can be. I'm going to ask my witness to make some -- to testify as to certain things, and then I'm going to turn -- I'm going to offer him up to you for all purposes. But I want him to have the opportunity to say anything he thinks because he has a lot of knowledge, and I think the Commission will benefit from his knowledge and experience.

I think that's all I need to say. Thank you.

I'll call Phillip Goetze.

CHAIRWOMAN SANDOVAL: Please swear the witness under oath.

PHILLIP GOETZE,

after having been first duly sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BROOKS:

Q. Good morning, Mr. Goetze.

A. Good morning, Mr. Brooks.

Q. You and I have worked on several previous cases; have we not?

A. That's correct.

Q. Okay. Acid-gas gases -- acid-gas injection wells, are they not among the most complicated cases we handle?

A. That's correct.

Q. Were you the -- were you the OCD person who was involved in the negotiation and approval of the C-108 for this -- these wells?

A. Yes. The C-108 was previously submitted, and there has been discussion about it and review of it up to this point.

Q. And you have had various conversations and meetings with the representatives of the Applicant for this purpose?

A. That is correct.

Q. So are you going to be testifying as both a fact and expert witness?

A. That is correct.

Q. And since we can -- so we can offer you as an expert witness, I would like you to review your education, experience and any other credentials that are relevant.

A. So I will start. My name is Phillip Goetze. I am an employee of the Oil Conservation Division Engineering Bureau. I've done this since 2013.

A quick summary of my background includes years with the Bureau of Land Management, the United States Geological Survey for oil and gas, as well as coal; United States Bureau of Mines for wilderness assessment, again brought back by the Bureau of Land Management for resolution of oil and gas issues in the Powder River Basin, as well as Wind River.

After that, a series of employments as a geologist doing geophysics for hydrology and engineering, followed by remediation projects involving sparge projects in New Mexico, Arizona, Texas. Also with that, oversight of drilling on behalf of the Department of Energy on several sites. And expand upon that, with the Arctic Slope, I was a federal technical oversight for drilling at Los Alamos. We can go through the list. We did risk-based corrective actions for Bureau of Indian Affairs, identified several issues and remediated sites for a US EPA consent -- agreement consent of order on the Bureau of Indian Affairs, Navajo Nation. I've worked on the storm water issues.

With that, moving into my last employment, I conducted Phase I's, established protocols for sampling used also at Los Alamos, prepared and reported for discharge permits at the location of Stage 1 abatement plans. And then as of recent, as an examiner for the Oil Conservation Division of over 300 cases, along with oversight as a technical reviewer of all UIC Class 2 applications that have occurred in the last six, seven years.

With that, I can also throw in registered professional geologist in the states of Arizona, Texas, Alaska, and a certified environmental manager, State of the Nevada, and published author.

Q. Do you have some degrees?

A. I've got one degree.

Q. Okay. Well, that's usually enough.

A. That's right.

Q. Can you tell us about that?

A. It was a fun time. I have a degree in 1970, Bachelor of Science, from the New Mexico Institute of Mining and Technology, otherwise better known as New Mexico Tech.

Q. And you list quite a number of associations that you belong to, and it's probably not a necessity to go through all of them because the list is rather long, but are there any you want to particularly mention?

A. Not at this point. We'll save it for another time.

Q. Very good.

Now, do all -- in your opinion, do all these credentials qualify you to testify as an expert in geology and hydrogeology?

A. I believe they do.

Q. Very good.

MR. BROOKS: We will submit Mr. Goetze as an expert in geology and hydrogeology.

CHAIRWOMAN SANDOVAL: Are there any objections?

MS. CALLAHAN: No objection.

Q. (BY MR. BROOKS) Now, Mr. Goetze, is Exhibit 4 a copy of your resume containing credentials that you just -- is OCD Exhibit 4 a copy of your credentials -- your resume containing a list of your credentials?

A. That's correct.

Q. Okay. Now, you have presented me with a mercifully short number of exhibits, and I ask you first to look at Exhibit 1 that's got all these circles on it and tell us what that shows.

A. Division Exhibit Number 1 is Figure 4 referenced by the Commission. What is plotted here are all the wells that currently have either a valid permit, an expired permit or are actively injecting into what we refer to as the Devonian-Silurian interval.

The blue circles is a system of evaluation at this point, which is still administrative, looking at a three-quarter-mile radius as a means of seeing what type of overlap and what potential interference between wells. Also highlighted on this are other disposal wells that are in the area of the Capitan Reef. We have production as well as injection into shallower zones.

And with that, we just want to bring to light that we do have a Libby Berry Fee SWD No. 1, which is the closest active SWD. It has operated for only a short period of time and has achieved at this point a daily injection of 14,476 barrels of water per day. It is within what was the application made for this well, which requested 20,000 to a max of 25,000. We feel that the remainder of the wells in this area, if operated on a similar injection rate, would not pose a potential interference to the AGI wells in the sharing of the same interval based upon the current information given to us.

Q. Okay. There are -- there is a minimum separation between the two AGI wells. Is that because it is not planned to utilize the same two at the same time?

A. We assume that they would be available to use at the same time. They are located based on the best judgment of the Applicant as to what their needs are.

Q. Okay.

A. The quantity of gas of these facilities is much lower than other facilities we have currently operating.

Q. Thank you.

MS. CALLAHAN: Excuse me, Mr. Brooks. Do you happen to have an extra copy of this exhibit that we can look at?

THE WITNESS: No. You can't have any.

(Laughter.)

MR. BROOKS: Do I have one, Mr. Goetze? I do not.

THE WITNESS: Yes, you do.

I know these by heart.

MS. CALLAHAN: Well, I just -- it's not so much I want to look at them, but --

MR. GUTIERREZ: I've looked at them before.

MS. CALLAHAN: You have? Okay.

MR. GUTIERREZ: Yes.

Q. (BY MR. BROOKS) Okay. And the only wells shown on this exhibit are injection wells, right?

A. Correct.

Q. Nothing shown about production wells?

A. That's correct.

Q. Okay. Now, what is Exhibit 2?

A. Exhibit 2 is a table -- oh, actually, Exhibit 2 is the response -- we made a review of the original application. We approached Geolex to -- to assess the potential for induced seismicity. There had been concerns raised with this location in the area of known faults, as well as historical production as represented by the Lee [phonetic] well to the north of the unit. So it is a duplication of what has already been incorporated as Exhibit 5 by the Applicant. So we merely included it such that it provided a confirmation that we received it and we had reviewed it and we're satisfied with the end product.

Q. Okay. And a follow-up on that, Mr. Gutierrez testified that they responded fully to all your requests for more information about induced seismicity and that you approved -- you approved their results; is that accurate?

A. I would say that we are comfortable with the results provided to us, since the Division is still learning its way through induced seismicity at this time. But it follows protocols that are accepted by other agencies doing the same thing.

Q. Well, a detailed study of induced seismicity is somewhat in its early childhood; is that correct?

A. That is correct.

Q. Okay. What is Exhibit 3?

A. Exhibit 3 is essentially a summary table of our current acid-gas wells, and this is provided to the Commissioners so that if you have, you know, a prospectus of what we have currently. These are not very common wells. The level of information we require based upon the years that we've put into them has become a much higher quality than would typically be found than, say, a saltwater disposal well. So we know that these wells will be increasing numbers. At this time we would -- as always, we look to the Commission to provide us guidance if we need to fill in a gap or if they see a void in the way we're approaching these. So this is more of a courtesy so you can see where we are.

Q. Now, at present does the Commission require that all applications for acid-gas injection well approval be presented directly to the Commission and not to a Division hearing?

A. That's correct. We have adopted that approach, that the Commission be able to look at and comment, as well as, again, point out any deficiencies the Division may not have seen.

Q. Now, why are some of these wells green and others are not?

A. The green wells are no longer acid-gas wells.

They originally were applied for and received authority. They have since gone to straight slickwater disposal and no gas going in.

Q. And what about the one -- what about the one well highlighted in beige?

A. The bottom well, the Monument No. 3, represents a second well at the facility. This represents the approach the Division has taken to having redundant wells at these facilities. The No. 1 was lost and had to be plugged and abandoned, and with that, the operator came back to the Division for request for a new well, which was approved, and with that, the understanding that they would also put a redundant well in as part of their AGI system.

Q. It says -- the API number send "pending" on that well.

A. They're still working on getting that APD.

Q. Okay. Now, are there any -- is there anything else you want to say about this exhibit at this time?

A. Nothing other than this is a current status.

Q. Okay. We've gone through the short list of your exhibits.

Now, Mr. Goetze, we have called you as a witness not to take a position on this application but rather to offer the -- to be of whatever assistance we

can to the Commission, correct?

A. Correct.

Q. With that in mind, could you please -- I'm going to ask you to state in narrative form whatever you feel is advisable to tell the Commission or appropriate to tell the Commission before you offer yourself for questioning.

A. There was a recommendation that I provide an exhibit -- an additional exhibit. This additional exhibit is a list of conditions of approvals that were in previous orders. So counsel for the Applicant is aware of it. And in many cases, these are the same conditions we find now for every one of our orders. If I may, I would wish to enter Exhibit Number 5, which is a list of these conditions and make it available to the Commission.

Q. You may do so.

CHAIRWOMAN SANDOVAL: Are there any objections of entering this into the record?

MS. CALLAHAN: No. We have no objection.

CHAIRWOMAN SANDOVAL: Okay.

(NMOCD Exhibit Number 5 is offered and admitted into evidence.)

Q. (BY MR. BROOKS) Okay. Now, there was testimony by Mr. Gutierrez about some additional requests that you

made concerning the subject of induced seismicity during the administrative review of this application. You were present when Mr. Gutierrez testified on this subject; were you not?

A. Correct.

Q. And do you concur with his judgment that all of these issues were -- were resolved to your satisfaction?

A. It's correct.

Q. Okay. Is there anything else you wish to say at this time?

A. I do have one recommendation to the Commission and have discussed with the Applicant, and it's well design -- and this would be Figure 4 and Figure 5 of the C-108 application. We would ask that the Applicant add an additional string of casing such that that string is solely to cover the Salado so that it can be submitted as a single unit. Historically, we like to see this in areas where we have shallow injection, as well as historically where we've had issues of water flow in Salado. Having a good casing cement section through that gives the Division a much higher level of confidence that the integrity of this well will not be impacted by other folks. So we would request that the Commission include a request to the Applicant to add that string.

The Division also understands that this will be an APD issued by the Bureau of Land Management, that they will have the final say in what goes into this, especially through their Onshore Number 2 order. I don't think they'll oppose it, but I think this enhances the quality of these wells.

Q. What depth is the Salado?

A. Based upon the Libby Berry Fee SWD No. 1, which is to the east of the proposed wells, we're looking at an interval of approximately 2,100 feet to 3,500 feet. The BLM will have specifics on how to tie in, and we would honor those.

Q. That's a very great deal of shallow injection zone we're dealing with here; is it not?

A. Well, in proximity to where the reef is and, again, a reef transition into the back reef where we do have Yates and Seven Rivers production in this area, as well as injection back into it historically going back many years, I think this would be beneficial.

Q. Thank you.

Anything else?

A. I could make a comment about the review of the C-108. The application as provided to us and the supplemental information, we feel that they have met all the requirements as necessary for the basic C-108

application and have provided additional information
which is consistent to what we have approved before
Commission with regards to acid-gas injection wells.
Q. Okay. Now, is the C-108 a part of the Applicant's exhibits --
A. Yes, it is.
Q. -- that were offered in the proceeding?
A. It is.
Q. Where would I find it? Would I find it following those exhibits?
A. It is Exhibit 1.
Q. Okay.
A. It is included in there.
Q. And what page does it start?
A. What page -- front of the book, page 1.
Q. Okay. Oh, yeah, I see. There's your printed form. It's actually the second page after the cover.
A. Uh-huh.
Q. Okay. And is the rest of the -- is the rest of this Exhibit 1 the C-108?
A. That's correct.
Q. And its attachments?
A. Yes.
Q. Okay. And is the C-108 complete with all attachments?

A. With the addition of Exhibit 2, which is the signature page for the affirmation statement, yes.

Q. Very good.

Anything else?

A. Let's see. Oh, approval of the APD, we would just have the Applicant verify that there is a bond in place so our financial assurance is verified.

MS. CALLAHAN: I can bring him back on.

THE WITNESS: Well, just go ahead and provide that.

MS. CALLAHAN: Okay.

THE WITNESS: Under our Rule 59, we're making sure that there is bond in place for the well, since it will be BLM and out of our realm. We just want to go ahead and make sure.

Q. (BY MR. BROOKS) Okay. With the recommended conditions that you have spoken about, do you recommend to the Commission that they approve this application?

A. I would suggest strongly that they look at it and review it. Many of them have already been addressed in the presentation by the Applicant, and it's just a matter of incorporating it in the order so that down the road, we can find it, and so the operator, as well as our compliance people in the field are seeing the same list.

Q. And any successor operators also?

A. Well, that's another thing, too. We don't know who is going to inherit it, so --

Q. Very good.

MR. BROOKS: At this point then, I'll pass the witness.

MS. CALLAHAN: I have no questions.

CHAIRWOMAN SANDOVAL: Does the Commission have any questions?

COMMISSIONER KESSLER: I have one, yeah.

CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. Mr. Goetze, do you have any remaining concerns about the overlap in radius between the two -- between these injection wells -- acid-gas injection wells and the proximate SWD well?

A. If it were a condition of approval, that they maintain what is submitted in their C-108 of maximum of 20,000, I think that would enhance the abilities for these to stay away from each other. It doesn't appear that that well is capable of getting up to 20,000, but I think putting it in the rule would -- or at least in the order would give 3Bear a notice or whoever comes in, because it is a possibility that well may go to someone else while the gas facility remains with another party.

So the potential for future conflict is always there.

CROSS-EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. 20,000 on the saltwater disposal well?

A. Their application asked for 20,000, and they're getting 14,000. That would be the Libby Berry Fee SWD No. 1, API number 3002544288.

Q. And that is currently operating?

A. Yes, it is.

Q. Sorry. I just to want to clarify. And the requirement on that currently is a max of 20,000?

A. What it tends to -- under our UIC Program, an application will come in and we approve it. We, under rule, only have a maximum surface injection pressure, which is the administrative .2. We have never put into rule rates and volume controls. We are now doing this on a case-by-case basis for those cases appearing before a hearing examiner or a commissioner.

I think in terms of the life of this well, being able to put a rate limit on it, with the possibility for that to be addressed down the road as an option, with the recommended conditions of approval, we're doing those ten-year milestones. And I think this will be something that, as the operator, they would look at to see how the well is performing and what problems they're having, should it be from another source.

So right now we, at .2, have no issues. If we just go ahead and limit the volume at this time until, say, that first ten-year review, see how it works, it may be advantageous.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. Limit the volume of the --

A. Saltwater disposal well.

Q. -- saltwater disposal well?

And you're recommending we do that in the acid-gas injection well order?

A. You can reach out for conditions, since you are sharing the same injection interval.

Q. Okay. Thank you, Mr. Goetze.

COMMISSIONER ENGLER: My turn?

CHAIRWOMAN SANDOVAL: (Indicating.)

CROSS-EXAMINATION

BY COMMISSIONER ENGLER:

Q. Let me go back to something. The first point is, you know, you asked the Commission to look at an additional string through the Salado?

A. Correct.

Q. From 21- to 35- feet, roughly?

A. Uh-huh.

Q. So in terms of their design -- so you're looking at either an additional string, or can I extend the string?

A. We would like an additional string. I think stand-alone, it just -- every time we've had a flow issue, we've had salt issues and we've had issues of fatigue and corrosive environment, as time goes by, we've numerous cases where we've got Salado water flowing. And in some cases, we've got it where we're -- and I don't really wish to get too far off drift, but actually the water flow in the Salado has caused the cement to wash out. So I think considering what's been going down the hole in these wells, the insurance is worthy of it.

Q. Oh, I appreciate, again, this table in the form that I can read other than what I saw earlier when I pulled it.

I guess the question of -- again, this is a list of AGI wells. Over time, in your experience, have you seen changes in terms of design or anything in terms of what's going on in terms of this acid-gas injection?

A. Oh, yeah. We have seen a much more conservative approach to these wells. The concept of converting wells or reentry has gone by the wayside.

Q. Okay.

A. These tend now only to be used for gas injection instead of gas and water, multipurpose.

We have worked with the operators with getting downhole information. They have brought to us -- and we do have in certain wells an agreement going on that -- there is no real prudent history of sensors being used downhole as far as -- well, their life and how they will react in acid gas. So in cases where those permanently installed sensors are capable of failing, we've asked them to come back and do a pressure test downhole and actually run a bond for a week or two and get some real numbers. So it is coming along with better design, better information coming out of the reservoir and better performance, because, again, as you expressed on the model, the model is only as good as the data that goes into it, and certainly what type of model you run is going to change over the life as we get better information and better predictable models.

Q. Yeah. I noticed. -- I heard this earlier. There is this ten-year look-back or ten-year review of, I assume -- one well is close to coming to that, and so that, I would think, would be really valuable on our assessment of how these acid-gas injection wells are performing.

A. That's correct.

Q. And that's going to be what, a couple of years from now?

A. Correct.

Q. It seems to me the Siluro-Devonian is becoming the preferred target.

A. Oh, now we're drifting.

Yes. The --

Q. I'm a professor. I drift a lot.

A. Originally under our primacy agreement, we had two areas identified as disposal, one being San Andres and then correlation-wise, the Delaware Mountain Group. And then the primacy agreement also identified the Devonian at that time, in '83, as a potential disposal zone, but it was ruled out due to the economics, as the history of oil and gas development has gone through very, very dynamic changes.

When I first came on here, the Delaware Mountain Group was the preferred injection interval, but we had incidences of where it had a cluster of wells, approved saltwater disposal wells, that had washed out producers in the horizontal. We also, with horizontal drilling, came to understand that the Brushy Canyon could be a producer, though we had approved numerous injection into it as a dumping ground. So horizontal drilling changed everything so that the Delaware

Mountain Group, which was a garbage can, was now a prized target. We also had several cases presented by Yates with regard to what is happening in the San Andres, that we're building up pressure. So drilling through this pressure-up system, we would end up increasing costs and, of course, changing radically the drilling design but also increasing the ability for an out-of-control situation.

The decision to move to the deeper wells was supported by industry in general, but it also now has created its own issues. The induced seismicity is more prevalent. How do we deal with volume moving up into larger-size tubing and, therefore, larger injection? A lot of assumptions have been made, which still need to be addressed. Correlations were very poor. How much of a confining layer do we see in the Ordovician? We're trying to keep everybody out of Ellenburger because we know it's just a pathway to the Precambrian. Questions about the fault slip model. It's a fine model, but what kind of seismic do you base it on? And so these requirements to provide the Division with some sort of process to review these and issue permits has caused us to now create a situation where we have as many as 200 applications waiting for Devonian.

Q. Huh.

Let me ask one other final question. I guess this follows up on Jordan's and I guess to help me out as a new commissioner.

So you have this water injection and gas injection, same zone. You develop an overlapping circular area. So what's the consequences or -- well, first, we're monitoring or hopefully monitoring. So what's the consequences if these two boundaries interact? We're assuming that this is going to be viable under the rate controls we're stating --

A. Uh-huh.

Q. -- or possibly state. But, you know, by and large, what happens if these do interact, or how do we monitor or stop that?

A. Well, this is one of those questions in the ten-year analysis we're hoping to find out. At this point we're really working on the basis of the model and experiences in other -- like Canada and what they've had.

Q. Yeah.

A. My expertise in that would be very limited, but my greatest concern would be is it would change the injection radius, the possibility of moving it, and with that, that interaction would impact how we regulate it and what we say as this is your box to work in.

Q. Because I find, again, in the seismicity data in the table, you actually have a maximum stress of north 60 east --

A. Uh-huh.

Q. -- which happens to be from one well to the other.

A. Uh-huh. That's correct.

Q. Thank you.

A. You're welcome.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. Just a brief follow-up. Would you recommend a ten-year plan -- a ten-year report, or would you --

A. Oh, yes.

Q. -- expect a report before that?

A. Well, I mean, this becomes a real question. By the time -- how much data can you get in and look at your model and work it? We chose ten years based on a 30-year life. And even with the 30-year end of review, if it's going to extend beyond that 30 years, a 30-year report becomes critical to justifying extension of that order. The general consensus is is that much information that comes into it, at that time you would have viable data to work with.

CROSS-EXAMINATION

BY CHAIRWOMAN SANDOVAL:

Q. That was actually right along my question, but I don't want to belabor this point. So you talked about possibly having a limitation on the disposal well. But would there be any need for limitations on volumes of the acid-gas wells, or is that the 8,000, or is that adequate?

A. Your application will spell out the -- we do incorporate in the orders the actual volume that is requested. And with that, it puts into that administrative -- or that Commission order that limit, and then you'll have to clarify is this something that can be shared between both wells. So that allows for operation and shifting. But you will specify -- in their application, that is the limit that those two wells will be permitted to utilize.

Q. And you believe that limitation is adequate to provide protection kind of from that saltwater disposal well?

A. At this point, the information we have, yes, it is.

CHAIRWOMAN SANDOVAL: Are there any additional questions?

Would you like to redirect?

MS. CALLAHAN: Yes. And I think it might be easier if we just brought Mr. Gutierrez back onto the stand. He'll be better able to address some of the questions that have been raised and your questions to Mr. Goetze.

CHAIRWOMAN SANDOVAL: Have you completed your questions?

MR. BROOKS: Yes. I am prepared to pass the witness.

CHAIRWOMAN SANDOVAL: Okay. You're dismissed.

MR. BROOKS: Oh, one question. I don't believe we ever offered your exhibits --

THE WITNESS: Oh, yeah, we haven't.

MR. BROOKS: -- in accordance with the OCD custom of offering the exhibits at the end of the presentation instead of offering them as they are identified and discussed the way it's done in court.

So at this time I will offer OCD Exhibit Numbers 1 through 4 -- and do you have 5?

THE WITNESS: Yes. That's correct.

MR. BROOKS: I would offer Exhibits 1 through 5.

MS. CALLAHAN: No objection.

CHAIRWOMAN SANDOVAL: Okay. Exhibits 1

through 5 will be included.

(NMOCD Exhibit Numbers 1 through 5 are offered and admitted into evidence.)

MR. BROOKS: Pass the witness.

MS. CALLAHAN: I ask Mr. Gutierrez to return to the stand, please.

MR. LOZANO: Just to remind, Mr. Gutierrez, you're still under oath.

THE WITNESS: Yes, sir.

ALBERTO A. GUTIERREZ,

after having been previously sworn under oath, was re-called, questioned and testified as follows:

DIRECT EXAMINATION

BY MS. CALLAHAN:

Q. Mr. Gutierrez, you just heard Mr. Goetze testify regarding the possibility of the intersection of the plumes of the saltwater disposal well that 3Bear has that is closest to the proposed acid-gas wells. Can you address the concerns and perhaps speak to the volume -- the affected volume of the acid gas in relation to perhaps barrels to get an idea?

A. Sure. I think I want to emphasize two things, I think, with respect to that. And when we talk about interference between these two plumes, we're really talking about two different things. We're talking about whether they actually mix in the reservoir or whether the pressure effects from the two wells affect each other. And they are really two different things.

The model calculates a displacement of a certain amount of fluid in the reservoir based on what we're injecting. Say in the AGI instance, we're only putting in approximately 3,500 barrels a day versus 20,000 barrels a day that are potentially coming in from the SWD No. 1 or the 14,000 that are actually coming in at present.

The concern -- I guess we don't have a significant concern about the interaction between injected salt water and injected acid gas, and I'll tell you why. The reason is because the reservoir's already filled with brine. And basically the salt water that's being injected, while it may be a slightly different composition, it's still brine basically, and the -- as I mentioned in response to a question that was raised earlier, for the most part, what we have seen is that this acid gas stays as a separate-phase plume except the very margins of it. So it doesn't really seem to have a compatibility problem with the existing fluid that's in the reservoir since that's the same fluid basically chemically -- I mean, it may have less magnesium, a little more magnesium, but it's essentially the same kind of brine in the saltwater well. We haven't seen an issue with that.

Now, one of the things that Mr. Goetze raised, which I think is a good point -- and my client does not have an objection with going with a four-string design -- is the possibility for, you know, the conditions in that Salado to have a deleterious effect over time in our well and this provides added protection. We don't have a problem with that. It's likely going to be required by the BLM anyway. So we would not have an objection with that.

The one thing I would raise and I do have a little concern with and I'm not sure I have the answer for how to deal with it other than to say, as Mr. Goetze said that, you know, Applicants are bound by what they put in their application, which are incorporated by reference into the orders that are issued.

I have a little bit of a concern with trying to limit the volume of salt water injected into a different well in this order, and the reason why I have a problem with that is for the very same reason that Mr. Goetze raised earlier, which is at some point in the future, maybe there will be two different owners of these two wells. And so I would say that whatever you do relative to the saltwater well or any clarification of what volumes should go into that well should be something that's handled in the order associated with that well rather than in this order because of that in the future.

I don't think that there is necessarily an objection to it, and there is an acknowledgment by the Applicant that, you know, we have submitted a request for injection of 8 million cubic feet, which that's what would be our limitation. I know it's a little different with saltwater wells because the State only has the limitation of the MAOP from a statutory perspective, but in the same way, they do look at what volume is requested in an application, and that's incorporated into the order.

But it's just my concern to mix the two. I don't think there is an objection necessarily to that limitation in this case, but I'm just not sure that the AGI order is the best place for it.

Q. I think that's all.

CHAIRWOMAN SANDOVAL: Does the Commission have any questions?

CROSS-EXAMINATION

BY COMMISSIONER KESSLER:

Q. Mr. Gutierrez, will there be an objection to the ten-year mark providing modeling -- updated modeling

on the pressures on those same faults?

A. No, absolutely not. And we would be doing that anyway. And, you know, the real content of these ten-year reports, no one knows yet because we haven't done one yet, but we will, and we'll figure it out, you know, with what the Commission and the Division needs. We'll work -- I mean, we're committed to working closely with the Division, as we have for the last 15 years, in developing the right approaches for these things.

CROSS-EXAMINATION

BY COMMISSIONER ENGLER:

Q. So this ten-year review, we've yet to decide how we're going -- or what we're going to use?

A. No. There's been a general statement in the orders of what would be the requirement for ten-year reports.

Q. In past orders?

A. That's right, in these past orders. But basically it's been a relatively general requirement, that it will be to review the actual conditions in the reservoir and how the reservoir has responded to that injection versus how it was projected to respond.

Q. So really your pressure, your rates and over time, you know, temperature, that's really everything -- that's what you need?

A. That's right. That's right. That's right, and the bottom-hole data.

Q. Well, yeah. The surface and bottom hole, yeah, again if you're capturing the bottom hole, is really valuable.

A. Right.

Q. But that -- okay. I need to learn more. Thank you.

CHAIRWOMAN SANDOVAL: Are there any additional questions?

MS. CALLAHAN: I guess I just want to make one additional redirect related to Exhibit 5 of the Division's exhibits.

REDIRECT EXAMINATION

BY MS. CALLAHAN:

Q. Mr. Gutierrez, have you conferred with your client and does your client have any objection to incorporating any of these listed provisions in the order?

A. I haven't really conferred with my client specifically about this, but when I look at these conditions, they're not outside of what would be anticipated in the order. And, in fact, if you look through our C-108 in detail, I think you'll find that we've committed to doing most of these, if not all of them explicitly in the application.

MS. CALLAHAN: Madam Chair, if you'd like, I can bring Mr. Solomon back and he can address that question, if you wish, or you can just require those in the order.

CHAIRWOMAN SANDOVAL: I don't think there is a need to do that.

MS. CALLAHAN: Okay.

THE WITNESS: I will make one minor comment about item four on this list. It says, "Include a biocide...in the annular fluid (diesel) of the well." We do do that, but I think it would be even more important to say that that should be not only biocide but corrosion-inhibited diesel as well. They're two different things, and we -- we usually use corrosion-inhibited diesel with a biocide. We have a little recipe for that stuff (laughter).

CHAIRWOMAN SANDOVAL: Are there any additional questions?

MS. CALLAHAN: No.

CHAIRWOMAN SANDOVAL: Okay. Thank you.

If it wishes, the Applicant can make a brief closing argument.

CLOSING STATEMENT

MS. CALLAHAN: I guess as I said at the

outset, I think that the testimony presented here today has reflected that the C-108 as proposed and with the incorporation of the conditions that the OCD as requested is approvable. And, again, I think everything that has been done to -- in the engineering aspect of it and the protections that they've established in the C-108, I think the environment is going to be protected, and I think it will offer substantial economic benefits to the State of New Mexico. We ask that you approve it.

Thank you.

CHAIRWOMAN SANDOVAL: The Division may now make a closing argument if it wishes.

MR. BROOKS: We have nothing to add, Madam Chairman, Commissioners.

CHAIRWOMAN SANDOVAL: Thank you.

The record of this application hearing is now closed. The Commission will immediately deliberate so as to reach a final decision on the application. Pursuant to the administrative adjudicatory deliberations exceptions to the Open Meetings Act, Section 10-15-1H(3), the Commission may deliberate in closed session.

I will entertain a motion to go into closed session.

COMMISSIONER KESSLER: Move that we go into closed session.

CHAIRWOMAN SANDOVAL: Do I hear a second?

COMMISSIONER ENGLER: Second.

CHAIRWOMAN SANDOVAL: I move that the meeting be closed pursuant to the administrative adjudicatory deliberations exception to the Open Meetings Act, Section 10-15-1H(3), to deliberate in Case Number 20409.

Do I have a second?

COMMISSIONER KESSLER: Second.

COMMISSIONER ENGLER: Approved.

(Laughter.)

CHAIRWOMAN SANDOVAL: Motion approved.

MR. LOZANO: Madam Chair, you need to take a roll call.

CHAIRWOMAN SANDOVAL: A roll-call vote, please.

MR. LOZANO: Commissioner Kessler, if you're in favor.

COMMISSIONER KESSLER: I'm in favor.

MR. LOZANO: Commissioner Engler?

COMMISSIONER ENGLER: In favor.

MR. LOZANO: Madam Chair?

CHAIRWOMAN SANDOVAL: I'm in favor.

The Commission will now close this session and the record.

(Recess, executive session, deliberations, 12:05 p.m. to 12:57 p.m.)

CHAIRWOMAN SANDOVAL: So I guess we are back on the record following the closed session, so I want to state for the record that the deliberations during the closed session were limited only to those things that were specified in the motion to close.

The Commission meeting and record is now open. Discussion in closed session was limited to the deliberation in Case Number 20409.

I will now entertain a motion to approve the C-108 application from 3Bear, LLC.

COMMISSIONER KESSLER: Madam Chair, I move to accept the C-108 submitted by 3Bear Field Services, LLC for the two AGI wells as indicated in the application for the following reasons: The AGI well minimizes the negative impact on the environment and prevention waste of the H2S gas.

The Commission approves the application with the following conditions, and I'm referring now to Exhibit 5 that was submitted by the Oil Conservation Division. I'm going to go through those conditions and modify occasional conditions that are set forth in the order.

So the Commission approves 1 through 3 as stated in Exhibit 5.

Exhibit 4, we would like to include -- we want to modify to include biocide and corrosion-inhibited diesel.

5 through 8 will remain the same.

Number 9 shall be modified to include a contingency plan for impacted gathering lines, which includes a GIS mapping layer to be provided to the OCD.

No changes to 10 through 13.

Number 14 shall be modified to provide a report every fifth year and should be modified to include an update on seismic modeling. We would also like the modifier to include that those reports be in-person presentations to be given to the Commission at their discretion.

Condition 15 will be as stated in Exhibit 5.

16 shall be modified to include an additional casing string covering the Salado Formation, an estimated depth of 2,100 to 3,500 feet.

Conditions 17 and 18 are as stated in Exhibit 5.

And there are also certain additional conditions that we would like to have included in the draft order: Verification of the bond with the BLM be provided to the Division. And in the event of change of ownership, the Applicant shall appear before the Division to obtain approval of said change of ownership or operatorship. And this application is to be granted for a period of 30 years from the date of the order. At that time the Applicant shall appear before the Commission requesting an extension if so desired.

And finally, in my motion, Applicant, please propose language in the order to address the Libby Fee SWD No. 1 injection rate, and we will review that language. Proposed language could include an offer to amend the original application of Libby Fee SWD No. 1.

That concludes my motion.

COMMISSIONER ENGLER: Second the motion as given.

CHAIRWOMAN SANDOVAL: All in favor of the motion say aye.

COMMISSIONER KESSLER: Aye.

COMMISSIONER ENGLER: Aye.

CHAIRWOMAN SANDOVAL: Aye.

(Ayes are unanimous.)

CHAIRWOMAN SANDOVAL: The motion is approved.

Are there any questions from the Applicant?

MR. SOLOMON: No. It's clear.

MS. CALLAHAN: If we provide a draft of the order for your review, will you review it and hopefully approve it at the next hearing?

CHAIRWOMAN SANDOVAL: Yes, if that is provided to us ten days prior to the next hearing so that we have opportunity to review it prior.

MS. CALLAHAN: Okay.

MR. BROOKS: Madam Chair, Commissioners, that's fine. I don't care about the procedure that's actually used in this case. I just wanted to make a point that since I've been here a number of years, the custom of the Oil Conservation Commission has been for any proposed drafts to be submitted first to the Commission counsel, who would then prepare a draft to submit to the Commission.

MR. LOZANO: Fine.

CHAIRWOMAN SANDOVAL: Okay. So please submit that to counsel.

MS. CALLAHAN: We will.

CHAIRWOMAN SANDOVAL: With that, we will move on to item number seven of the agenda and discussion of pending litigation.

(Case Number 20409 concludes, 1:04 p.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, 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 or attorneys in this case and that I have no interest in the final disposition of this case.

DATED THIS 18th day of June 2019.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2019
Paul Baca Professional Court Reporters