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:

ORIGINAL

APPLICATION OF DCP MIDSTREAM, LP FOR AUTHORIZATION TO INJECT ACID GAS INTO THE ARTESIA AGI #2 WELL, SECTION 7, TOWNSHIP 18 SOUTH, RANGE 28 EAST, N.M.P.M., EDDY COUNTY, NEW MEXICO.

CASE NO. 15127

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

June 19, 2014

Santa Fe, New Mexico

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BEFORE: JAMI BAILEY, CHAIRPERSON
TERRY WARNELL, COMMISSIONER
ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, June 19, 2014, 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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(9:05 a.m.)

CHAIRPERSON BAILEY: We have no orders to sign today, so I will call Case Number 15127, which is the application of DCP Midstream, LP for authorization to inject acid gas into the Artesia AGI #2 Well, Section 7, Township 18 South, Range 28 East, in Eddy County, New Mexico.

Appearances?

MR. RANKIN: Good morning, Madam Chair. Adam Rankin with Holland & Hart on behalf of DCP Midstream. We have two witnesses today.

MR. WADE: Good morning. Gabriel Wade on behalf of the OCD, and the OCD will have one witness.

CHAIRPERSON BAILEY: Do you have an opening statement?

OPENING STATEMENT

MR. RANKIN: Thank you, Madam Chair. If I might, I have a few comments to put the application in context.

Today DCP is here on its application for a second acid gas injection well, the Artesia AGI #2. By its name, it would be the second acid gas injection well for the Artesia gas plan. The first well was permitted and approved 12 years ago and has operated and continues to operate reliably. However, the reservoir that it is disposing into is slowly filling up, and in order to meet demand and in order to be proactive about increasing demand and drilling in the southeast part of the state, DCP is looking for an additional reservoir and has found one. In fact, it's not a new reservoir. It's one that their current saltwater disposal well has been injecting into for some time. However, it's an ideal reservoir for acid gas, as they have determined.

So today you will hear about those technical and geological characteristics of this new proposed target injection zone, and you'll hear about how the second AGI, which will act as the primary injection well in this case, will allow the plant to meet the existing demand, will allow DCP to meet the plant's current operating capacity and will allow DCP to have additional operation flexibility, to operate both wells together as necessary or as appropriate and to use the first AGI well as a redundant or backup well if necessary.

Today Mr. Gutierrez, our second witness, will provide a full summary of the technical details provided in the C-108 application. We'll also have a witness, our first witness, a DCP witness, who will give a little background about the Artesia Gas Plant and why DCP is looking for a second acid gas injection well today.

Finally, also, we will touch on the proposed conditions that the Division has recommended to the Commission, and we've had a chance to discuss those with the Division's counsel and have reached agreement, we believe, on all conditions that the Division has proposed.

So with that, I have two witnesses, and I'd appreciate your consideration of our application.

CHAIRPERSON BAILEY: Mr. Wade, do you have any opening comments?

MR. WADE: Other than Mr. Rankin stated the case accurately, and we will discuss those conditions as well through Mr. Goetze.

CHAIRPERSON BAILEY: Would you call your first witness?

MR. RANKIN: Thank you very much, Madam Chair. My first witness is Mr. Russ Ortega.

CHAIRPERSON BAILEY: Please stand to be sworn.

RUSSELL GILBERT ORTEGA,

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

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good morning, Mr. Ortega.
A. Good morning.
Q. Will you please state your full name for the record?
A. Russell Gilbert Ortega.
Q. And by whom are you employed?
A. CDP Midstream.
Q. And where is it that you reside?
A. I reside in Seminole, Texas, but I work in Hobbs, New Mexico.
Q. Okay. And what is your position with DCP?
A. My position is asset director, director of Operations for the southeast New Mexico north asset.
Q. And what do your duties include in that position?
A. Pretty much the overall management of the asset, which incorporates four processing plants and four gathering systems, all the safety involved. I work with the Safety Department, the Environmental departments and Operations to try to manage smooth operations.
Q. So part of your duties includes overseeing the -- your duties in Operations includes the permitting required to operate the facilities and bring on new equipment, that sort of thing?

A. Yes, sir. I'm part of that process.
Q. How long have you been with DCP now?
A. Well, I've been with DCP since 2000. I've been in the industry. Prior to that, I was with Phillips Petroleum for -- I've been in the industry for 33, almost 34 years now.
Q. And how long have you been in your current position with DCP?
A. In my current position, eight, close to nine years.
Q. Now, in --
A. And that's as a director of Operations. I've been in southeast New Mexico for about a year and a half.
Q. And in your role, you're familiar and have oversight and responsibilities of DCP's gas plants?
A. That's correct.
Q. And their AGI operations as well?
A. Yes, sir.
Q. And by AGI, I mean acid gas injection?
A. Yes, sir.
Q. Will you give the Commission just a brief overview of DCP's operations in southeast New Mexico?
A. Well, we have the Linam Plant, which is our biggest plant in southeast New Mexico. It's kind of a

hub. We have a number of other facilities that can move gas to the Linam Plant, including the Hobbs Plant, Antelope Ridge, some from the Eunice Plant and the Artesia Plant depending on the capacity at the time at the Linam Plant. We do have the ability to move some volumes up to about 30 million from the Artesia Plant to Linam, but if we have the Hobbs Plant down or Antelope Ridge with an issue or something like that, the capacity isn't there to move the whole 30 million.

Q. So stepping back, DCP is a service provider to oil and gas operators in the field, correct?

A. Correct.

Q. And the service you provide is to gather gas -- what services do you provide?

A. We provide gathering and gas processing for our producers.

Q. And some of the gas down there has got H2S in it; is that correct?

A. That's correct.

Q. So part of your service is to manage that H2S?

A. That's correct.

Q. And how does DCP manage the H2S now? What is the preferred methodology for managing the H2S?

A. In my asset, the preferred -- and for DCP -- is acid gas injection.

Q. And what's the reason for that?

A. Well, the acid gas injection utilizes reciprocating and centrifugal compression, which is a lot less maintenance intensive than a sulfur recovery unit. I've been involved with sulfur recovery units since I started with this industry, and the AGI process is just way more efficient from a cost standpoint and an operation standpoint.

Q. Are there any other environmental benefits that you see as a result of transitioning to an acid gas injection program?

A. Yeah. There are a lot less issues with the acid gas type systems, and I know that we have tail gas coming out of our SRUs that you don't see with an AGI system.

Q. So as a consequence, by transitioning to more acid gas injection, is it eliminating some otherwise atmospheric emissions?

A. Could you repeat that?

Q. Sorry. Poorly worded.

By transitioning to AGI for disposal of acid gas, is DCP eliminating or mitigating some otherwise -- emissions that would otherwise occur?

A. That's correct. We're eliminating the tail gas that comes out of your tail gas incinerator, and I know we have to meet a certain percentage. So it's a minimal amount, but it's still an emissions we can do away with by utilizing AGI.

Q. And, Mr. Ortega, today you're appearing as a fact witness, correct?

A. Yes, sir.

Q. And have you also prepared some slides or exhibits to review with the Commissioners today?

A. I helped putting these slides together. Yes, sir.

Q. Great. Would you mind please just walking through your first slides over here? There is an overview of the Artesia Gas Plant. Would you please describe what the Artesia Gas Plant is and what it does?

A. Sure will. To start off with -- and it's not one of these dot points -- the Artesia Gas Processing Facility has the capacity of 90 million cubic feet per day, and that's with an AGI that we just installed, which is a recent upgrade. It gives us the ability to move about 2 million cubic feet of acid gas, total acid gas, which enables us to get up to that full 90 million in capacity at the plant. The 2 million cubic feet additional -- or not additional, but the 2 million that this new compressor gives us is made up of about 30 percent H2S and about 70 percent CO2.

The existing AGI compressor that we had was only capable of moving 1.5 million max a day, which, with the acid gas available coming from the producers, we weren't able to bring in the full 90 million volume. So we either had to move those volumes to the Linam Plant with a spillover or, on occasion, when Linam was full, like I was mentioning earlier, we would have to curtail producers. And we used a ratable curtailment so that we weren't just hitting one producer.

We also produce about 600 barrels, on average, of waste water or produced water that's currently being disposed of in our saltwater disposal well on the plant location. The Artesia Plant employs approximately 25 full-time employees, and we provide gas processing services for about 120 producers. A couple of those are fairly significant producers in regards to the volumes they bring to the plant. A lot of them are smaller, independent, kind of mom-and-pop type of customers.

Q. Mr. Ortega, just to highlight a few points on your slide, the treated acid gas that's being injected consists of 70 percent CO2?

A. That's correct.

Q. That CO2 is effectively then being injected and is essentially being sequestered in the reservoir that you're disposing into; is that correct?

A. That is correct.

Q. CO2 would otherwise be -- would have been admitted to the atmosphere without the injection?

A. A portion of it, yes.

Q. And then with respect to the wastewater, what's the source of that wastewater?

A. There's a number of different sources. We have the produced water coming into the inlet of the plant with the gas stream, along with hydrocarbon condensate. We separate that in our inlet separation. The water eventually goes to our disposal well. We also have cooling towers that utilize water for cooling, and that water rebuilds chlorides and that type of thing, impurities, and we have to have a constant blow-down on those cooling towers in order to remove those impurities.

And on occasion, we also have trucks from the gathering system bringing in liquids that include hydrocarbon condensate and water that we separate. All that water eventually goes down our saltwater disposal.

Q. Now, this is the well that DCP will be shutting in and plugging and abandoning once this -- hopefully this AGI #2 is approved and goes into operation?

A. That's correct.

Q. And the reason that DCP is seeking a -- what DCP is asking for in its application is the ability to inject either treated acid gas with water or dry treated acid gas; is that correct?

A. That's correct.

Q. So one of the reasons -- what's the reason that it's asking for the ability to inject wet treated acid gas?

A. Well, we're looking at other options at this point in order to find another source for disposal, but if we can't find or get another disposal well, we would need to go with the wet acid gas injection in order to get rid of the produced water.

Q. Does DCP have a preference in terms of what type of acid gas injection well it would prefer to operate this plant?

A. Yes. We would prefer to go with a dry -- the dry well, and, again, if we can utilize another option in order to get rid of our produced water.

Q. And if DCP is able to find another option, would it then select the dry acid gas injection well?

A. That's correct.

Q. Would it then notify the Division that that's what its intent is?

A. Yes, sir.

Q. And Mr. Gutierrez, our second witness, will address the technical aspect of the saltwater disposal well?

A. Yes, sir.

Q. Now, your next slide, Mr. Ortega, I think discusses some of the goals, the reasons DCP's asking for this application?

A. Well, it's definitely an enhancement, and it will improve reliability. And when you say improve reliability, that encompasses a couple of real important things. Number one, excess emissions. If we can improve the reliability on our acid gas injection, it will help reduce the excess emissions from upsets, downtime and that type of thing.

One other thing is the safety. If we have a redundant well to go into, we can switch, and we're not scrambling because we're trying to avoid the flaring or the impact to producers, that type of thing. So it gives us some flexibility and gives us some time to not have to scramble to work on a unit. And in my mind, that adds a bit of safety to the reliability portion on this.

It also allows for simultaneous operation or, as I mentioned, alternate. Again, in order to get to that 90 million, we've got to be able to move the

2 million of acid gas into the well, and this well is filling up. And Alberto will cover the technical aspects of it, but we're looking at five to eight years' life expectancy left on this reservoir. So in order to increase that flexibility and reliability, with this additional well, we can swap back and forth, as I mentioned. We would have just a complete other train.

We have had some issues with leaks on the tree. As a matter of fact, just yesterday we had a wing valve that had a failure on the diaphragm. The valve closed, so we were down, flaring. We had to back out producers in order to minimize the flaring in order to make the repairs on that. If we had that redundant well, it would have been a seamless switch over to the other well, and we wouldn't have incurred near as much emissions, prolonged shutdowns. I think that's a key to the reliability and the reduction in excess emissions.

And then as far as our customer service, it'll help provide uninterrupted, for the most part, service for our producers in order to get us up to that full capacity. If we're able to run them simultaneously, we may be able to move even more than the 90 million capacity. We'll just have to see. That's kind of in the future.

Q. When you talk about flaring, if there is any downtime on the existing AGI #1 well, what has to get flared? Is it both the plant and potentially the wellhead?

A. Yes, sir. Whenever we have to curtail or back out gas in order to reduce the volumes going to our acid gas flare, that impacts producers. They'll have to shut in wells if it's going to be a prolonged outage. They'll either have to shut in wells. If they shut in wells, they lose oil production. So for the most part, they flare at the wellhead in order to maintain oil production.

Q. Mr. Ortega, just for the record, do you mind just explaining briefly what it is that gets flared and why, so we understand?

A. At the facility, we flare the acid gas, which is, again, a combination of H_2S and CO_2, at the wellhead. That's just going to be raw gas coming off the wellhead, which would include everything from methane, H_2S, propane, butane, that type of thing.

Q. So it's burned actually in order for it to be a safe emission; is that correct?

A. That's correct.

Q. But it nonetheless results in emissions of greenhouse gases and other substances?

A. Yes, NO_x/O_2. There are other emissions when you burn.

Q. Nitrogen oxides --

A. Yes.

Q. -- and other -- other -- sulfur oxides and things that --

A. That's correct.

Q. -- things that people don't want to see in the atmosphere generally, right?

A. Yes, sir.

Q. And then I think your last slide touches on the proposed project timeline for the well?

A. Yes, sir. In the Permian Basin, I think everybody's aware of the rising gas production. There's a lot of activity, especially in the Artesia area. If anybody's driven through that area, it's just getting very active. And with that there's an increased demand on the gas plant capacity to support the production in these areas.

We've been running this AGI well at Artesia for about 12 years now, and it's been operating, performing pretty well. It's a 24/7 operation, and that's what our customers expect. So, again, when we have issues, it impacts our customers and producers, and then, again, adds to a negative impact on the environment.

The new well, it'll be located at Artesia Plant. The total acid gas lines from the compressors going to the well will be coming from the acid -- or the amine treater. The well, it'll be drilled as a deviated well, and it'll be completed consistent with a carefully developed AGI design and will be in compliance with New Mexico OCD guidelines and the recent New Mexico OCC-approved AGIs.

Geolex and Mr. Gutierrez, they were retained in June of last year to evaluate the potential for this new well. They prepared and submitted the application on March 23rd of this year. So hopefully we're moving forward.

Q. Speaking of moving forward, Mr. Ortega, DCP has a lot of activity going on right now with its other applications that have recently been approved. How does this asset fit into the time frame or time schedule that DCP is doing with the other acid gas projects that have already been approved?

A. It's very important. Best case, we're looking at December 2013 start -- or 2015 start date. We do have the Linam #2 well and the Zia wells that we're moving forward with ahead of this, and this is about the earliest we can get to it. But we want to get to it as soon as we can.

Q. Part of the reason for that is because you're currently not able to meet plant capacity?

A. On occasion, that's correct.

Q. And you've got increasing demand already out in the field that you're not able to service?

A. Yes, sir.

Q. And, Mr. Ortega, have you had a chance to review the Division's proposed conditions that were a part of the pre-hearing statement submitted by the Division?

A. Yes, I have.

Q. And is it your understanding that DCP has reached agreement with the Division on the proposed terms?

A. That's my understanding.

Q. And with respect to their proposed condition number seven, which addresses monthly reporting of the daily gathered information on the C-103, is it your understanding that you have reached an agreement to provide that reporting on a quarterly basis?

A. That is my understanding.

Q. And then with respect to item number 14, condition number 14, as proposed by the Division, asking DCP to address impacts due to the injection of the saltwater disposal well that you discussed, is it your understanding that Mr. Gutierrez has included the volumes and the historical injection from that well in his calculations?

A. That's my understanding.

Q. And then Mr. Gutierrez will discuss any more specifics in his testimony with respect to these conditions; is that right?

A. That's correct.

Q. Mr. Ortega, did you help prepare these three slides that you reviewed today?

A. Yes, sir.

MR. RANKIN: I'll move to admit this later in Mr. Gutierrez' testimony, but I have no further questions.

CHAIRPERSON BAILEY: Any cross?

MR. WADE: No cross.

CHAIRPERSON BAILEY: Commissioner Warnell?

COMMISSIONER WARNELL: Yes. I have a few questions.

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Good morning, Mr. Ortega.

A. Good morning.

Q. Have you ever testified before the Commission before?

A. No, sir.

Q. How often do you go to the Artesia Plant? You say you're officed in Hobbs.

A. Yes, sir. If everything's running good, I try to get there once or twice a week.

Q. If for some reason the Artesia Plant shuts down, how do you bring it back up online? Like yesterday you said you had a problem. Did you shut the whole plant down or --

A. No, sir. We reduce volumes on the inlet to the plant to minimize the flare at the plant. We do have some very little line pack capacity if it's going to be a short duration. If I'm not mistaken, it was a couple of hours yesterday. So that would entail, I believe, a shutdown to booster sites, which would result in the producers having to curtail some volumes.

Q. So there is somebody at the plant 24/7?

A. Yes, sir.

Q. You mentioned you have four plants and four gathering systems, the Linam, Hobbs, Antelope and Artesia plants?

A. I've got the Linam Plant, the Artesia Plant, the Hobbs Plant and the Pecos Diamond Plant.

Q. For the record, could you please explain the difference between a plant and a gathering system?

A. The gathering system, we're gathering the raw gas from the producer, coming from the wellhead. We move it to trunk lines most of the time that send it to a booster station, which is compression. We boost the pressure up on some of the gas, the majority of the gas, up to plant inlet pressure, so it can get in the plant. We do have some low pressure coming into the plant, also, from compression out in the gathering system. The gathering system, like it sounds, gathers the gas.

The gas plant processes the gas. And what we do, we remove or separate the raw gas with -- or your NGLs, your propanes, butanes and all that, we separate that from the methane gas that you burn on the stove in your houses and stuff; we separate those components.

Q. You testified that the SWD well will be plugged?

A. Yes, sir, prior to, if we're successful in getting this well in, prior to the new AGI well.

Q. So what will happen to that water you're presently injecting into that saltwater disposal well?

A. Again, we're looking for other options, possible -- and I think Alberto may cover this in his presentation, but we're looking at a couple of other zones to possibly drill another saltwater disposal well on site or in close proximity to the plant. And if that's not possible, then we would want to go with a wet gas well. Worst case, truck it. And that will be a last resort, in my opinion.

Q. I think you testified that you would prefer to have a dry well rather than --

A. Yes, sir.

Q. -- wet?

Why is that?

A. You know, my opinion, we're going to be trying to run two wells simultaneously or have alternates. The existing well that we have there at Artesia is dry. Again, it's operated for 12 years pretty much without any issues on the well itself. Whenever we have to switch back and forth, we won't be able to go down the existing well with that water acid gas stream, so there's going to be additional equipment that we're going to have to install in order to be able to divert and not put the wet solution down the existing well.

And, again, this is my opinion, in talking to engineers, our asset engineer on site. He's worked with a wet gas well before. He's had some freezing issues and that type of thing. So there are just inherent additional issues that you could experience on a wet gas well.

Q. Okay. So the #1 well has been operating for 12 years, and I think you testified that it's maybe good for another eight?

A. And, again, Mr. Gutierrez will be the better person to answer that, but my understanding is eight to five years is what the life expectancy is on it.

Q. So assuming it was eight years, then you're looking at a total life expectancy of the #1 well of 20 years?

A. Of the #1 well?

Q. Yeah. It's been operating for 12 years.

A. Oh, yeah. Yeah. Yes, yes, yes.

Q. Do you know what the life expectancy of the #2 well is? I know Mr. Gutierrez is probably going to tell us this.

A. No, sir. I don't have a number for you.

Q. Thank you. No further questions.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Thirty percent H2S. That's the highest cut, I think, of any of the AGI wells that we've looked at in the last couple of years anyway. Is that -- that's really just a regional area that you're gathering the gas from --

A. Right.

Q. -- has a high amount of sour gas?

A. Yes, sir.

Q. Is that projected future growth in that area also going to be sour gas? Do you see that ratio changing either direction?

A. I don't see it going down, but that's just my opinion.

Q. But it may go up a little bit?

A. Possibility.

Q. The existing saltwater disposal well, is there a particular reason you shut that down?

A. It's in the same zone that we'll be going in with the new AGI well, and we can't utilize that saltwater well in the same zone as the AGI well.

Q. Thank you. Those are my questions.

CHAIRPERSON BAILEY: And the other Commissioners took my questions, so I have nothing.

Do you have any redirect?

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Just a quick question, Mr. Ortega. With respect to Commissioner Warnell's questions about the life expectancy of the existing AGI #1 well, is it your understanding that the life expectancy is dependent upon the injection rate as opposed to any equipment issues? It's the injection rate that you're talking about?

A. Yeah, that's correct. And my understanding -- and I've seen some trends. It's continued to -- the pressure on that reservoir has continued to climb. Depending on if we get more -- like we were talking about, adding to that percentage of CO_2 or H_2S, it could escalate and reduce the life expectancy, I would guess. And, again, Mr. Gutierrez can probably answer that better than I can.

Q. But if the injection rate in that AGI #1 were to be significantly decreased, the life expectancy of that reservoir --

A. Yeah.

Q. -- may be prolonged --

A. Yes. I see where you're going with this. Yes.

Q. Thank you, Mr. Ortega. No further questions.

CHAIRPERSON BAILEY: You may be excused.

THE WITNESS: Thank you.

MR. RANKIN: Madam Chair, I'd like to call my second and final witness, Mr. Alberto Gutierrez.

CHAIRPERSON BAILEY: Would you please stand to be sworn?

ALBERTO A. GUTIERREZ,

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

DIRECT EXAMINATION

BY MR. RANKIN:
Q. Mr. Gutierrez, can you please state your full name for the record?
A. Yes. Alberto A. Gutierrez.
Q. And by whom are you employed?
A. Geolex, Incorporated.
Q. And what's your position with Geolex?
A. I'm the president of Geolex.
Q. And how long have you operated Geolex?
A. Twenty years.
Q. And what have you done -- what do you do for Geolex? What's their business?
A. Well, I'm a professional geologist, and we do a wide variety of different types of geological and engineering types of projects in the groundwater contamination area, groundwater remediation, but we also have a defined specialty in acid gas injection. So we do a lot of acid gas injection projects throughout the United States and overseas.
Q. How many acid gas injection wells have you worked on to get to the permitting and development process?
A. In excess of 20.
Q. And how many have you done in New Mexico?
A. Now, all of them except for one.

Q. All -- all --
A. All the ones that exist in the state except for one.
Q. Have you previously testified before the Commission?
A. Yes, I have.
Q. Have you previously had your credentials as an expert in petroleum geology, acid gas injection operation and design and hydrogeology and groundwater contamination accepted and made a matter of record?
A. Yes, they have.
MR. RANKIN: Madam Chair, I would tender Mr. Gutierrez as an expert in those subjects that I just recited.
CHAIRPERSON BAILEY: He is accepted.
MR. RANKIN: Thank you very much.
Q. (BY MR. RANKIN) Mr. Gutierrez, did you prepare the C-108 application that was provided with the application?
A. I did.
Q. And I'd like to mark the C-108 as Exhibit Number 1.
And did you also prepare a PowerPoint presentation summarizing the aspects of the C-108 application?

A. I did.

(Exhibit Number 1 marked.)

Q. Are you prepared to review that summary for the Commissioners?

A. I am.

Q. Would you please -- does the C-108 that's been marked as Exhibit Number 1 contain all the technical information necessary to approve the AGI #2?

A. Yes, it does.

Q. Will you please walk the Commissioners through your slide presentation?

A. Sure. Basically, I want to just kind of go over first what are the topics that we're going to discuss.

The first one has already been addressed by Russ, and that's kind of what the overall rationale is for the project and the timeline. We can talk a little bit more about that as you have questions regarding the roles between the two wells, et cetera.

Then I would like to summarize the key aspects of the proposed AGI well, which is a little different than ones that we have done before in front of the Commission because we're asking for the flexibility to have either a wet or dry well. Now, we certainly have had this Commission permit both wet and dry wells before but never one where we didn't -- although by permitting a wet well, in effect you're permitting a wet and dry well because you're not always injecting wastewater in conjunction with the TAG. But in this case, we're asking specifically for that, and I'll go into what those reasons are. So it's a little bit different than the normal application in that sense.

I'll then also go into a discussion of the detailed geology of the injection area and the reservoir and maybe give you also a little better sense of what's happening with the existing AGI reservoir and the new reservoir that we have identified here.

Then I will go over the key design features of the well, as well as going through and looking at the surrounding production and groundwater resources in the area and how we will protect those through our design and our geologic interpretations, and then the conclusions and what we are asking the Commission to do relative to this well.

So let's talk about some of the key elements of the C-108. You already have that. As we mentioned, this well is intended to ultimately provide the primary disposal well for the treated acid gas from the Artesia Plant. Now, currently, as we mentioned, the AGI #1 has been continued and is continuing to be used.

It works well. It's a good well. However, the reservoir does have some limitations, and we'll discuss those in more detail down the road. However, we are seeking the -- and that's why DCP really is wanting this well, because as the Commission is well aware, we have come, over the last 12 to 15 years of doing these projects, to recognize the importance of having a redundant well, because it provides an opportunity for the operator not to, per se, increase capacity or whatever, but it provides an opportunity to be able to live switch between two injection points that allows for working one over or doing well work on a well without going to flare and without curtailing producers. So that redundancy capability is one that will allow DCP to avoid even more shutdowns than they currently -- avoid through the use of AGI #1.

Also, nearby oil and water wells -- there really aren't any nearby water wells, but the nearby oil and gas wells will certainly be protected by the design and the geologic factors, as will any freshwater resources there, which, as you'll see from our discussion, are pretty scant. As a matter of fact, the plant does not have a water supply well. It receives its water -- municipal water from the city of Artesia, and that is, in fact, who supplies water to all of this area, because there really is very little, if any, fresh groundwater in the area.

So we'll go over the detailed log interpretation that has permitted our delineation of the reservoir, and we'll demonstrate why it is protective of existing wells.

Also, as Adam alluded to, the application does have all of the information necessary to approve the second AGI well. And we are currently in the process of revising the H2S contingency plan for the Artesia Plant so it will include this new well, in addition to bringing the plan up to spec with the Rule 11 requirements.

Operators and surface owners have all received proper notice, and we have not had any objections to the project.

Okay. So let's really summarize what we're asking for here. We're requesting authority to inject acid gas either with or without wastewater from a second well. It's a deviated well, and I'll go into why we've chosen that. But fundamentally, the reason to make it simple is that we want the surface location as close as possible to the existing AGI #1. However, the best part of the reservoir that we're after is basically on the other side of the plant from the surface location. And so we want to get to that better part of the reservoir, and the way we intend to do that is by deviating the well.

The well will be completed into the lower San Andres, the Glorieta and the upper Yeso areas there at depths of approximately 3,600 to 4,300 feet. And the maximum operating pressure, if we use it as a dry well, only would be about 1,700 psi. If we had a mixture of the total TAG volume and the total wastewater volume, then that MAOP would be significantly reduced because the density of the fluid is greater, and it would be around 916 psi, is what we've calculated.

As I mentioned, the real preference for DCP is to operate this as a dry well, but as of right now, we don't see a -- we don't have lined up another saltwater disposal option. However, we are looking into a few of them, and I can brief the Commission on kind of where we are there.

If we use a safety factor that we have typically used of 100 percent of the actual volume for the treated acid gas, we would be looking at something in the neighborhood of 4 million cubic feet a day of treated acid gas and 600 barrels a day of wastewater. The wastewater is fairly easy to predict what that amount is going to be because it's a fairly constant production. It varies seasonally, but, I mean, the average is about 600 barrels a day.

The radius of the influence of the proposed well with that combined injection fluid was less than four-tenths of a mile. There is no current or anticipated production in the injection zone within a mile of the site. Actually, it's probably within about two miles of the site.

There are only three wells that penetrate the injection zone currently, and those wells are -- two of them are located on the plant itself. One is the original AGI #1. The other is the saltwater injection well, the SWD #1, and the third is -- approximately half a mile north of the facility, there is a commercial saltwater disposal well not in the same reservoir, and we'll go into some detail there. But I just want to make sure the Commission keeps in their minds that we're talking about really two different reservoirs.

The current AGI is completed at a depth of approximately 11,200 feet into the Devonian. And as Mr. Ortega, Russ, alluded to, what is happening -- the reservoir, which is not unusual for Devonian reservoirs in the Permian Basin, has got limited porosity and permeability and also limited areal extent. And so what we have seen in the operation of that well over the last

12 years is that the pressure in the reservoir is gradually rising. And it is not rising dramatically, but it is gradually rising. And there are two issues that come to play.

One is that ultimately we believe -- and that's what Russ was referring to. We've done an analysis of that reservoir, and at the current injection rate, we feel like that reservoir would probably be approaching the MAOP in a period of about eight years. But there is even a further issue with that, and that is that the MAOP for the well is actually higher than what the plant is capable of producing in terms of a surface pressure. Right? So they can't even -- even if they wanted to, they couldn't reach the MAOP with the surface injection facility, because being an 11,000-foot well, it's got a pretty high MAOP.

But in any case, the desire is to have a well that can be used to off-load some of the volume that is injecting into the #1 well while still maintaining the #1 well as a redundant well. And so the idea is to use the #2 well as the primary well, but still keep the #1 well in operating condition and allow for this important capability to switch back and forth.

As I mentioned, there are only three wells that penetrate the injection zone within the one-mile area of review. And the one well, the existing AGI #1, protects the current injection zone with actually two strings of casing, because the intermediate casing and the production casing -- the intermediate casing for the AGI #1 extends below this current injection zone that we're proposing, and, of course, the production string does as well. And it's well cemented throughout the entire injection zone.

The second well which we are proposing to plug is the saltwater disposal well. Now, the reason -- and this is to get back to Commissioner Balch's question, why would we plug the saltwater well. Well, the saltwater well has been in existence for 25 years, 20 years at that facility. It is a converted dry-hole deeper well that was plugged back up. And, frankly, the well is -- while I'm really glad that the well is there, because unlike -- and the Commissioner will appreciate this. Unlike most of the applications that we have had, with the exception of one other one back about eight years ago, we never have had the opportunity to directly test the reservoir that we intend to use for injection prior to drilling the well. So in this case, we actually took the opportunity to run a step-rate and a long-term injection test with the current saltwater disposal well that gave us some pretty good reliability -- added reliability to our analysis of the reservoir.

However, the well itself is not in the best shape. The well is partially silted in from where it was plugged back, so actually even the entire zone that we anticipate using for injection was not available for testing because the well is silted in about 200 feet. And even so we still had very good results from that location. But the bottom line is that we feel that that well, if it is not plugged properly in this zone, could serve itself as a conduit for acid gas getting out of zone. So we feel we have access to it to easily plug it and completely isolate that zone, and that is what our intent is.

And then the third well, which is about a half mile north of the facility, again, outside the 400 -- the 100 percent safety volume area of review. That well is a Morrow well that was nonproductive and was converted to a Cisco saltwater disposal well. That well, we have very good records on its completion, and it is completely cemented through the injection zone and covered by intermediate casing as well. So that well we have no concerns about. And one of the things -- one of the options that we have looked at is DCP using that well, which is a commercial saltwater disposal well, as a mechanism for getting rid of their saltwater given that their preference is to have a dry injection well.

However, there are two down sides to that. One is that they feel they can only take 4- to 500 barrels a day in that well, and, secondly, DCP doesn't control that well. So if they relied on that well to be able to dispose of your saltwater, they may find themselves in a situation of having to truck water, which is very expensive and no one likes to do anyway.

So we are in the process and I believe in terms of a preview of coming attractions, not for today, that we have identified a zone relatively nearby where we will be putting in an application for a saltwater disposal well that we feel is consistent with -- that would not be the zone that we're currently proposing for AGI. And, again, it's not because we feel there is any problem with putting saltwater in conjunction with the AGI. We've got three permitted wells in the state that do that and have done it without a problem. But, again, my client's preference, because they operate and will, if this well is approved, ultimately have at least six AGIs operating in southeast New Mexico, all of the other five being dry wells, they would just, for operational simplicity and everything, like to keep this as a dry well as well.

Q. Mr. Gutierrez, you mentioned one acronym. I'd like to make sure it's clear for the record. You mentioned M-A-O-P. Would you just state what you mean by that?

A. Yes. That's the maximum allowable operating pressure, which is essentially the calculated pressure that you're allowed to use as a maximum surface pressure when you're doing injection.

So I think that that covers all of the discussion here. Let's go into the details of the proposed well. The new well's going to be constructed in Section 7, Township 18 South, Range 28 East. You'll see it in a figure here. It will serve as the primary injection well. There are the general pictures (indicating) so that you see where the plant is. The plant is located approximately here (indicating), about 15 miles or so southeast of the town of Artesia.

The existing Duke AGI #1 was drilled on the plant site. This well was drilled in 2002. It was permitted -- interestingly enough, if you look back at the order for this well, it was an SWD order. It was before the Commission really started permitting these wells. It was done administratively through the Division back in 2002.

The well is constructed basically as a dry

AGI well that is constructed in many ways very similar to the Linam #1 well. It is a deep well, 11,200 feet, approximately, into the Devonian. And the new well is going to be located approximately 200 or 150 feet away from the current surface location of the AGI #1, but after getting to a kick-off point below all the local potentially productive zones, we will deviate the well off to the southeast -- and I'll show you on a map exactly what that will look like -- to get to a better portion of this reservoir.

There we go (indicating). Let me just show you. This is the plant itself, obviously. This is the current AGI #1. This well, as I mentioned, is 11,200 feet deep, vertical well, into the Devonian. The saltwater disposal well that the plant currently uses is located right here (indicating). It was originally a dry hole that was plugged back and converted to a saltwater disposal well prior to when DCP even owned this plant. It was done by the prior owner of the plant.

And currently our proposed surface location for the new well is here (indicating). It will go down, as I mentioned, about 2,500 feet, and then kick off to wind up in this location (indicating), bottom hole.

Now, interestingly enough, DCP owns this property, actually, a little piece of property on the other side of this well. That's not why this location is here. You'll see the geologic reason for it in a moment. However, you know, one of the other things we thought about was, okay, we could take a pipeline and move the gas all the way across the plant, because the existing compression facilities are located up here (indicating), and then drill a vertical well over here (indicating). However, there are two issues. One, we'd have to cross this road with a high-pressure TAG line, and, plus, we'd have a high-pressure TAG line going all the way across the plant, which from a safety perspective, is not desirable thing. So the idea is we minimize -- if we put the well here (indicating), we minimize the additional run of high-pressure -- a line from the existing line, which is here (indicating). We would T off and go into the new well here (indicating). And it's just much better from an operational perspective. However, the geology didn't want to cooperate and be as good right below us as it is to the east.

The maximum anticipated acid gas injection rate is 2 million, as Russ mentioned. They are currently injecting about a million and a half, a million and three-quarters into the existing well, but if the plant was operating at full capacity and didn't have to curtail gas, then it would process and generate approximately 2 million a day of acid gas. Again, the combined stream would be 2 million a day of acid gas and 600 a day of wastewater.

We injected fluid compositions, approximately 30/70 H2S to CO2. It is higher than a lot of the other DCP wells, which are approximately 15 percent H2S and 85 percent CO2, but, interestingly enough, you know, it's reflective, as Commissioner Balch mentioned, of the increasing sourness of gas as you move to this part of the Permian Basin. As a matter of fact, the Agave Dagger Draw Metropolis well, which is also an AGI well that we permitted, is running about 50 percent H2S, 50 percent CO2. So as you move west in that part of the Basin, the gas gets crappier, basically, or more sour.

The injected fluid compatibility was determined by looking at the injection experience and a nearby formation fluid analysis. We don't foresee any issues there with either the wastewater or the TAG.

And as I mentioned, if we go TAG only, we would calculate a maximum operating pressure or maximum surface pressure using the NMOCD guidelines of about 1,700 psi. Again, that will depend exactly on the final depth of the perforations, and roughly about 900 psi if we were, for example, injecting wastewater only in that well. Because conceivably, if you -- you know, at times when we are operating both wells or want to shift back to an operation of the #1 well periodically in order to make sure that it's available and has no problems in operating when we need to switch to it, we could switch the acid gas to the #1 well and continue to inject only wastewater into the #2 well. Again, that's something we're hoping to avoid, and I think we'll be able to, but at this point we can't -- can't definitively say we couldn't do that.

Q. Mr. Gutierrez, would you mind just briefly explaining why it is that there are two different operating pressures for treated acid gas -- wastewater? Explain how that works.

A. Sure. And by the way, that's detailed in our application on pages, approximately, 6 through 8.

But the simple answer is that brine has a density of slightly greater than one. TAG has a density -- this TAG has a density of probably about 7 -- .78 or so. So the lower the density of the injected fluid, the higher the surface pressure to achieve the same bottom-hole pressure. And that's the concern that the Division has with any injection well, is what is going to be the bottom-hole pressure, because that is the pressure that you're subjecting the reservoir to, and you want to make sure you stay below the fracture pressure for that reservoir.

So if you inject fluid that is eight-tenths or .8 specific gravity versus fluid that's 1.05 specific gravity or 1.04 as you have much brine, then that's where the difference lies. Because actually the fluid itself, if it's more dense, it's heavier and therefore creates a higher bottom-hole pressure with a lower surface-hole pressure.

Q. Thank you.

A. So one of the things we did here, we had to do a few different scenarios to calculate what the plume extent might be after about 30 years of operation. And you can see here -- and this is detailed in the application -- if we're talking wastewater only, it would be about .19 miles over 30 years. TAG only, about .25 miles. The combined about .31. Now, this is a simplistic analysis because obviously the water and the TAG don't behave exactly the same. But we believe that it is -- it is accurate within the context of the information that we have on the reservoir.

We've also seen, by the way, in our testing of the reservoir that it does -- the injection -- the bottom-hole pressure does drop fairly -- and I don't remember right now off the top of my head what the values were, but the injection pressure dropped off fairly dramatically over a period of about five days, demonstrating that the reservoir really is not significantly being pressured up by the current and long-term disposal that has gone on of saltwater in there. And we used a representative irreducible water number for that reservoir that is representative of that zone in this area.

So these radii are shown on the following two pictures. This one is for TAG only (indicating). So realistically, in our preferred operating mode, where we would operate a dry well, this is what you'd be looking at after 30 years.

The darker purple line, the smaller one, you can see -- by the way, they are centered on the bottom-hole location, obviously, because that's where the injection is taking place rather than where the surface is. And the smaller dark purple circle is 2 million cubic feet a day for 30 years, about a quarter of a mile, in reservoir radius that is affected.

If you look at the lighter purple circle, that is with 100 percent more volume so that it would be the 4-million-a-day number for that reservoir.

And the black circle just outlines what the half-mile distance is from the existing bottom-hole location.

The next picture is a combination of TAG and wastewater. It also shows what it would be only for wastewater, although, you know, wastewater doesn't behave exactly the same as TAG. But if we use that same displacement model, we'd get this green circle for wastewater only, the light blue circle for a combination of 2 million feet a day of TAG, plus 600 barrels a day of wastewater.

The darker blue circle would be the 100 percent safety factor circle.

And, again, the black line represents the two-mile -- I'm sorry -- the half-mile radius.

Okay. So we obviously did go to -- in spite of the fact that we had less than a half mile affected there, because, you know, we have the other AGI in the area and also because of the fact that it is a deviated hole. We wanted to make sure we covered all of the potential operators or surface owners, and so we went out a mile from that zone and notified everybody. And I believe we have those receipts here to offer as an exhibit.

We did not receive any objections to DCP's application. We had inquiries from a variety of folks about their interests and stuff, but we didn't have any objections at all.

The adjacent operators are obviously, I think, pleased with the idea that this will improve the reliability and the ability for DCP to service them at their -- and have less interruptions in service. It will also allow for maybe increased throughput in the area and increase the royalties that ultimately get paid to the state.

Q. So, Mr. Gutierrez, on the -- on the notice point, the current rule requires half mile -- notice to all affected parties within a half-mile radius of the injection site; is that correct?

A. Well, that's what the current rules show. However, the policy has been to try and notice people for one mile. The proposed rules that -- that I understand the Division -- that we have been working on for a couple of years and that the Division intends to bring forth have a process similar that I described for half mile.

Q. So the individuals that you noticed -- looking at Exhibit 3, which is tab number three in the exhibit packet, is this a copy of the letter of notice that went out to all those individuals within a one-mile radius of the injection?

A. I don't have the exhibit packet in front of me.

Q. Let me get one for you.

A. Yes, that is correct. There are actually two notice letters that went out. The original one went out on April 17th and was followed -- and went out certified mail to all of the recipients. And I was embarrassed that there was a typographical error on the first notice letter, which said that the location of the facility was in Lea County, not Eddy County, even though the township, range and section were correct. So we sent a second letter out correcting that typo.

Q. So the typo is in the first sentence of the first letter?

A. That's correct. It says "at their Artesia Plant in Lea County, New Mexico," and then it goes on to give the current surface, township and range, but it's Eddy County, not Lea County.

Q. So following that first sample letter is a copy of all the certified mail receipts indicating all the affected parties who received -- who were sent notice; is that correct?

A. That's correct.

Q. Then following that there is a number of pages that include all those receipts, and the second letter that was sent out correcting the county?

A. That is correct. And it is the same -- the same, exact letter. It just corrected the county and said why it was being sent out. And, again, what we sent out with the notice to all of the people who are noticed was the summary -- the application form itself, and then it stated that if any party wanted a copy of the complete C-108, that we would make that available. And we had requests from probably about -- I'd say five or six different people that we noticed, to send them a complete application, and we did that.

Q. And following that second letter that went out is a copy of all the certified receipts indicating that notice was sent by certified mail to those individuals a second time?

A. That is correct.

Q. Thank you.

A. Yeah. And the second letter is dated April 29th. It was about 12 days after the first letter went out.

So I know that we have gone over this a number of times, but I'd just like to reiterate what is it that we look for when we're looking for an AGI reservoir.

Well, one, we look for a geologic seal that can permanently contain the injected fluids. We want to make sure it's isolated from fresh groundwater. We want to make sure it has no effect on existing or potential production, which is very important. And we want to make sure that it is laterally extensive, permeable and good porosity. Those are some of the features right there that the Devonian Reservoir doesn't have that this reservoir does. We want to have excess capacity available, obviously for injected volumes, because it just will reduce the overall extent of the plume, and we need a compatible fluid chemistry.

So the proposed zone that we're looking at meets all of those criteria, and I'll show you that in just a moment.

So to look at what are the wells in the area, we looked within a one-mile radius and then a half-mile radius of the bottom-hole location. There are 25 current wells and one permitted and not, as of yet, drilled well that were identified within the half mile of the proposed AGI location. That includes nine active oil and gas wells and six active injection wells, which would include both the Duke AGI #1 and the DCP SWD #1 and ten wells that are plugged and abandoned.

Now, there are a lot of wells in this area, but they're very shallow, mainly. So in this half-mile area, there are only three wells that penetrate the injection zone. All the rest of those wells are above the injection zone -- or actually above the caprock of the injection zone. These three wells are the Duke AGI #1, the DCP saltwater well and the State CG #1, which is the Ray Westall commercial saltwater well that is located approximately half mile north of there.

There are no wells that are completed or producing from the proposed injection zone in the area. As I mentioned, we know for a fact there are none within a mile, but from looking at the general area even further out, we don't see any productive wells in that area even beyond a mile to two miles at least.

A review of the completion reports indicate that the injection zone is properly isolated by all of these wells with the exception of the saltwater disposal well, which we intend to plug.

This (indicating) gives you a quick overview of the production in the area. You can see that the majority of the production is, frankly, marginal Seven Rivers-Queen production, very shallow production. As a matter of fact, this is one of the things that we've been looking at as a potential for some of the sands in the Seven Rivers and the Queen, the premier sand, which we are looking at as a potential saltwater disposal zone.

In this area, there are only three wells that are still producing from that zone, and, frankly -- to give you an example just off the top of my head, from what I recall, one of those has produced 18 barrels of oil in the last 20 years. Another one has produced about 500 barrels of oil in the last 20 years, and the one that's produced the most has produced about 18,000 barrels of oil -- it's a little further -- in the last 25 years. And last year, it produced a total of about 300 barrels. So, frankly, we think that there is some possibility for saltwater injection there, and that's one of the things that we're looking at in that area as a possible alternative.

But to get back to the AGI, as you can see, you can see where our proposed downhole location is, and the bulk of the active -- the wells in this area are producing from the Morrow in the area. That's really where the production is. There is some Grayburg -- slight Grayburg production, but that's petering out as well.

These are the only three wells that are penetrating the injection zone in the area (indicating). There is the State CO [sic] #1, which is a Cisco saltwater injection well. There is the Artesia saltwater disposal well, which is a Lower San Andres-Glorieta-Yeso well, and there is the Duke AGI #1, which is a Devonian acid gas injection well.

As I mentioned, all the wells that penetrate the injection zone effectively isolate that zone with the exception of the SWD #1, which will effectively isolate that zone once it's plugged and abandoned properly. The Duke AGI #1 has surface -- actually, surface of intermediate and production strings all cemented to the surface, and they completely isolate the injection zone. As a matter of fact, the injection zone that we're proposing is isolated by not only the production casing and cement, but the production casing, cement and the intermediate casing and cement in the Duke AGI #1.

The CG #1 also has surface and intermediate strings that are cemented to the surface, and the production string is cemented to within 600 feet of the surface, well within the intermediate string that also completely isolates the proposed injection zone.

By the way, those well records were provided also as part of the C-108.

CHAIRPERSON BAILEY: Before we get into the geology, why don't we take a ten-minute break?

THE WITNESS: Excellent.

MR. RANKIN: I'm sure our court reporter can appreciate that.

CHAIRPERSON BAILEY: Be back here by 10:30.

(Break taken, 10:22 a.m. to 10:34 a.m.)

CHAIRPERSON BAILEY: Back on the record.

Mr. Gutierrez, I think you were about to talk about stratigraphy.

A. I was.

The proposed well is located on the northwest shelf of the Permian Basin. And the San Andres, Glorieta and Yeso are porous marine carbonates, and they do have some detrital carbonates, and they're contained above and below by some low-permeability siltstones and shales.

So just to give you just a picture structurally where we are, we're located just off -- just off the edge of the northwest shelf, onto the shelf. And that's the reason why -- as I mentioned, you'll see from the stratigraphy of the wells, that there is really no -- I mean, I said that there was no shallow fresh groundwater. It's not exactly right. There is some alluvial groundwater, but it so happens that the alluvium, which is about 20 to 30 feet thick in this area, overlies the Salado Formation directly. So the Dockum Group is gone here. It's been eroded away.

So basically it goes straight from alluvium into, essentially, briny -- a zone that has brine water in it.

You get an idea of the northwest shelf here. This is the Salado Formation, as I mentioned, which is what is at the surface or under 20 feet or so of alluvium, underlain by the Artesia Group, which is the zone that has traditionally had some production in this area. Primarily that production has been in the -- in the Queen and the Grayburg, with some production in the Seven Rivers. Very shallow in this area.

Then the upper portion in this area of the San Andres is very tight anhydritic dolomites, and then we have some more porous and permeable carbonates that constitute the San Andres through the top of the Yeso. And then back in the Yeso, between that and the Bone Spring, we have another zone of very anhydritic material that is very low permeability.

And so here -- this is a geophysical log and characterization, a stratigraphy for the saltwater well on the site that DCP uses as a saltwater well. You see that the well is perforated in a number of zones within this interval, which is the interval that we're looking at for acid gas injection, which is overlain by this about -- almost 1,000 feet of anhydritic dolomite and dolomitic limestone that is very -- relatively impermeable. You'll see that on another log in just a moment. And then we have the Upper San Andres and the Grayburg. We've had a little bit of production, not within two miles of here in the San Andres, but we do have -- we have some old Grayburg wells that have played out that were producing from this area here and also from this area in the Queen (indicating). Most of the production in this area has been in the Tansill-Yates. It's very old production in terms of shallow production. And then we do have some deeper Morrow and Cisco production way below the zones that we're looking at.

The AGI #2 will be drilled approximately the same surface location as the #1, but it will be in a different injection zone, as we mentioned. The deviated borehole will also expose more of the porosity section to the wellbore than we would have with a vertical well, although, you know, based on the testing that we did of the existing saltwater well, that location would be fine as well. But if you'll look at the next two slides, you can get a pretty good idea of what I was talking about in terms of the stratigraphy.

Here we're looking at kicking off from about 2,700 feet, and then going off at approximately a 42-degree angle to go to the target injection zones, which is from this number one marker in the very lowest portion of the San Andres through the upper portion of the Yeso Formation, primarily in the Glorieta.

And then you can see these dark brown zones (indicating) are relatively impermeable and very low-porosity rock that is above and below the proposed injection zone.

Now, when you look at the average net porosity of the injection zone, this explains why we want to go to the southeast. Based on our mapping, what we see is that the best porosity, the thickest net porosity lies in this area essentially to the southeast of where we're located (indicating). The plant is located approximately here (indicating). You can see right now this injection well that I've got my arrow on here (indicating) is the current saltwater injection well. That's the one we tested. And as you can see, even though the porosity is less in that well than it is in this direction, even that well was still able to substantially take fluid at reasonable pressures at much greater rates than the rate that we would be injecting into in this zone.

For example, when you look at the combined injection rate, if we had to use it as a wet well, we would be looking at somewhere in the neighborhood of about a barrel and a half a minute of injected fluid, both wastewater and TAG combined. We took this well in the step-rate test up to seven barrels a minute, and we still hadn't broken over on the curve. And we're still at relatively low surface pressure.

So even in the not excellent part of this zone, we had some pretty good response in the reservoir. But we think if we go into this area, we are further limiting the extent of the plume and providing a better injection zone.

Q. (BY MR. RANKIN) Mr. Gutierrez, would you mind explaining what you mean by breaking over on the curve?

A. Yes. I'm sorry.

When you do a step-rate test, one of the goals of the step-rate test is to not only identify what amount and what the pressure is to inject different volumes of fluid, but you do a step-rate test to identify what the fracture pressure is for the injection zone itself. And that's typically called the break-over point when you're plotting the results of a step-rate test.

So let's talk a little bit about the general design of this AGI system. As we all know, over the last 12, 15 years, we've made improvements in how we design these wells, and, of course, we're going to incorporate those improvements in the design of this well.

As with all of the AGIs we have, the surface compressors and lines are protected with automatic safety valves to prevent overpressuring and to isolate the TAG lines in terms of any potential leaks that occur on the surface.

The well will include an automatic subsurface safety valve and a permanent packer that is corrosive resistant and that is capable of handling an injection stream of TAG only or TAG wastewater mix. The difference there being simply that the metallurgy that we will use in those will be a stouter, higher nickel-content metallurgy so that it would be essentially like you would design a wet AGI well. Because if we're asking the opportunity to do both, we want to make sure that the materials are consistent with that approach. So we've designed it essentially as a wet AGI well, which is overkill for a dry AGI, so to speak.

Fresh water will be protected by a surface casing, what little of it there is in the area, with the surface casing extending to about 500 feet, even though the depth -- maximum depth of fresh water in the area is about 60 feet. Then also approximately 250 feet of SM2535, which is a Sumitomo material -- but it's either that or the equivalent of it in terms of its corrosion resistance -- will be installed between about 3,400 and 3,650, approximately, and that's where we intend to set the casing -- set the packer and the packer seat.

The entire production tubing string will be lined with fiberglass to prevent corrosion in the event that we use it as a wet well, and the annulus -- and this is one thing that might be different. If we are able to find a saltwater disposal zone that we can permit effectively and can access prior to when we drill this well, which is our intent, then we might come back to the Commission and just say, Look, we'd like to use a different annular fluid. Because in a dry well, we would prefer to use diesel that is corrosion inhibited and biocide laced.

But if we're doing a wet well, we would use an acquiesce packer fluid that would also be corrosion inhibited and biocide laced, but we wouldn't be using the diesel in there. And that's the standard design for a wet AGI well like what we have at -- I still call it Southern Union, but it's Regency - Jal Plant and the Targa - Monument Facility and the Targa - Eunice Facility.

The annular injection tubing pressures will be continuously monitored and recorded both at the surface and at the bottom hole, which is what we are incorporating in the current design. You can see the general design of the well.

Now, there is one other thing that we have incorporated in a number of these wells which has not been necessary. However, in this well, it might be necessary, and that is the use of a downhole choke. And the reason is because we want to make sure at this -- while the reservoir conditions clearly will maintain the TAG in a super-critical state, we want to make sure that we don't have that TAG going out of the super-critical or liquid state when it is flowing down the tubing itself, if it's a dry well. I mean, if it's a wet well, it's less of an issue. But if it's a dry well, we want to do that. And the reservoir is so good that we may need that check valve in the bottom of the well just to maintain the pressure inside the tubing to allow the phase -- to not allow a phase change to occur as the fluids flows down the tubing.

The rest of the design is fairly similar to all of the other AGIs that we have permitted previously. I mean, again, in all of them, we have the ability to put this check valve. We usually don't have a need for it.

Q. Mr. Gutierrez, on this design that's proposed in the C-108, is there anything that would change if DCP is able to find a source -- an avenue to dispose of its saltwater and if DCP goes forward with a dry gas injection well? Is there anything that DCP would change in this design?

A. Like I said, the annular fluid. We may decide that we don't want to use line tubing as well when we use a -- we're still going to use a corrosion-resistant tubing section immediately above the packer to address any corrosion from the outside, but we may not line the entire string with fiberglass. But we would come back and advise the Commission. We may do it anyway just for added protection of the tubing string.

This is just a schematic that would show you kind of what the system overall for the two wells would look like (indicating). As I mentioned, we would be coming off of the pipe, the high-pressure TAG line, before going into the first well, taking it over to -- in the event that we have a dry well, it would just go over to the other well directly. In the event that it's a wet well, it would go to a mixing chamber where we blend the wastewater in the TAG prior to injecting it into the second well. So this is just a schematic to show how that would operate.

Now, because of -- you know, the preference is to have a dry well, but either way in this operation, we would have to have an ability to shunt off this line (indicating) if we wanted to be able to go back and forth from the dry to the wet and make sure that the water did not get into the #1 well.

Now let's talk a little bit about the casing string. All of the casing strings will be cemented to the surface, the surface casing, the intermediate and the production string, and we will verify that with circumferential cement bond logs that would be provided to the Division. The deviated production string will be cemented through the critical caprock area and the injection zone with corrosion-resistant cement. Now, we say "CorrosaCem or equivalent." That's just a tradename that Halliburton has. Schlumberger has one called EverCRETE, and I think BakerHughes has another one that I can't remember the name of. But essentially, we will use corrosion-resistant cement for that interval in the production string.

Also, in the deviated interval -- we talked about this when we did the Zia permitting -- we will use additional centralizers to make sure that the casing is centered in the borehole and that we get a good cement job around the casing.

The slide here that looks at groundwater conditions in the area of review, I think we've gone over that enough already, but just to let you know, we went through the same process we always go through trying to identify wells. There were only two wells that were identified within the one-mile area, water wells. And as best we can tell -- these wells are called the East and West Windmill, actually, on the State Engineer's database. But as far as we can tell, this may be -- one of these wells or maybe even both of them may have been drilled originally as monitor wells in the shallow alluvium because Phillips Petroleum had a surface impoundment there at some point in the past. And so as I mentioned, there is very little fresh water there. These wells are very shallow, less than 60 feet deep.

There are no other known water wells within a half mile of the AGI #2. And, you know, the Dockum Group, as I mentioned, is absent in this area, so you just don't have any fresh water below the alluvium. This is where the two Windmills are located (indicating). They're just off the west side of the facility. That's why we think this one may have been a monitor well (indicating). You can kind of see where the outline of the old impoundment was. And this well (indicating), I'm not exactly sure what its purpose was, but they've been there for a long time. They don't really exist with any surface facilities anymore. They're not used at all.

So let's summarize. What are the geologic factors that ensure the integrity of the proposed well? Well, we've done a pretty detailed review, and we have found no faults or structural pathways that could provide an avenue for acid gas to relieve the injection zones. We have good caprock above and below the injection zone. The injection zone is vertically and horizontally isolated from adjacent production. I mentioned that there is no production in that area for at least a couple of miles in that zone.

The thin alluvium is isolated by -- actually, the conductor casing will take you all the way through it and then furthermore by the surface casing in the intermediate. So we don't have any problem protecting that alluvial water where it exists.

And then the proposed injection pressure is well below the fracture pressure of the reservoir, and we know that not only from our straight-up calculations using the guidelines of the Division but also from conducting a step-rate test of that well.

And log analyses demonstrate that we're

dealing with a closed system.

So in summary, what we're asking for the Commission to approve today is an ability to drill, test and complete the AGI #2, as we have specified in the C-108 application and as would be further specified based on whether it winds up actually being a dry or a wet AGI well, and that we would request permission to inject acid gas at approximately 2 million cubic feet a day or a TAG wastewater mix of 2 million cubic feet a day and about 600 barrels a day of wastewater. We would be at a maximum operating surface pressures of 1,700, roughly -- 1,704 is the actual calculation -- for TAG only and then as low as 916 for wastewater.

Q. Mr. Gutierrez, one thing I neglected to ask you about when you were talking about the notice provisions, would you mind reviewing for the Commission what your process was for identifying the affected parties; how you did that?

A. Yes. As we normally do, we retained a land company -- in this case it was MDF in Roswell -- to go to the courthouse and go to the State Land Office and go to the BLM and identify -- first, it's a cascading notice. So we identify, first, all the operators, and then in the event that there is not an operator, we identify the lease -- mineral leaseholders. And in the event there are any unleased mineral interests, we identify those through that process, and that's what we use as a database to notify those parties.

Q. So at the time the application was filed, the notice was provided to those individuals who had interest of record at that time; is that correct?

A. That is correct.

Q. Now, switching gears to the Division's proposed conditions, you've had a chance to review those in the pre-hearing statement submitted by the Division?

A. I have.

Q. And it's your understanding that we've reached agreement on all of those conditions with some modifications of those conditions?

A. Yes, that's my understanding.

Q. And in particular, just going through them, just to be clear, on condition number two, in which the Division asks for a step-rate test on the well prior to commencing injection, is it your understanding that the Division is okay with DCP using a brine to conduct that step-rate test?

A. Yes. I mean, when I looked at the proposed condition, I assumed that that was what the Division wanted, because -- I mean, we never have done step-rate tests with TAG. We wouldn't do that. But yes, it's our intent to do it. We've already done one, actually, from the old well. But it's our normal practice, after we drill any AGI, to do a step-rate test and to look at the injectivity. So we would definitely do that, and it would help us to refine those MAOP values.

Q. So if the step-rate test showed something different, that would be the -- the MAOP that would be employed in this case?

A. That's correct.

Q. With respect to number seven --

A. Well, let me just say that we would use it to confirm the MAOPs that we've already calculated. If there was a desire or a need to increase an MAOP beyond what the Division's guidelines were, then we would use that step-rate test data for that purpose.

Q. And then with respect to condition number seven, DCP and the Division have agreed to provide quarterly reporting on a C-103 form?

A. That's correct.

Q. And your understanding with respect to item number 12 is that the Applicant, in this case DCP, was required to provide notice to the affected parties, but the Division was to provide notice of the Commission hearing in this case?

A. Yes. That's the routine procedure.

Q. I'm sorry. Let me state it correctly. The Division is to provide notice through a newspaper publication?

A. That's correct. That's a supplemental kind of notice of the hearing.

Q. And then with respect to condition number four, I think you did address this, but -- sorry. Condition number 14, requesting that DCP address the impacts from the historic injection from the saltwater disposal well, those figures, you indicated in your testimony, were included in your calculations with respect to the reservoir characteristics?

A. Well, we used the irreducible water that is representative of that zone in the area, and we further -- by doing the step-rate test and looking at the fall-off [sic], we're confident that using that irreducible water would adequately characterize what that reservoir's response would be.

Q. So your analysis included or incorporated the historic injection in that zone?

A. In that -- in that fashion, yes.

Q. Now, on that point, Mr. Gutierrez, finally just to summarize, in your opinion, will the design of the AGI in this case, the #2, enhance reliability and injection from the Artesia Gas Plant?

A. Yes, it will. Absolutely.

Q. And in your opinion, will the proposed injection pose a threat to any underground source of fresh water or drinking water in the area?

A. No. As I described, I think those sources, small as they are, are well protected.

Q. Will the granting of the application enhance and protect human health and the environment, in your opinion?

A. Yes. I think it will because it reduces emissions both from excess emission events from flaring, as well as the sequestration of greenhouse gas.

Q. And in your analysis of the assessment of the geology and existing oil and gas production in the area, in your opinion, will the granting of the application impair in any way the correlative rights or result in waste?

A. I believe it will not.

Q. And in your opinion, are acid gas injection wells the best available control technology for addressing and managing the disposal of H2S?

A. Yes.

Q. Mr. Gutierrez, were Exhibits 1 through 3 -- with the exception of the pages of the slide presentation which Mr. Ortega helped prepare, were

Exhibits 1 through 3 prepared by you or under your direct supervision?

A. They were.

MR. RANKIN: Madam Chair, I'd move into the record to admit Exhibits 1 through 3.

CHAIRPERSON BAILEY: Any objection?

MR. WADE: No objection.

CHAIRPERSON BAILEY: They are admitted.

(DCP Midstream, LP Exhibit Numbers 1 through 3 were offered and admitted into evidence.)

MR. RANKIN: Thank you. I have no further questions.

CHAIRPERSON BAILEY: Do you have any cross-examination?

MR. WADE: No cross-examination.

CHAIRPERSON BAILEY: Commissioner Warnell?

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Those shutdowns in the last 12 years, have there been any shutdowns in the Artesia Plant?

A. Oh, yes. Absolutely. I'm certain that there have been multiple shutdowns just because of the normal things that arise in plants. Plus, I am aware of a couple of instances or a few instances that have caused a shutdown of the AGI well.

Q. And if there had been a second well in place, would those shutdowns have occurred; do you think?

A. No, I do not, because -- well, there may have been a momentary thing, over a few minutes, in the amount of time it would take to switch from one well to the other. But that's the whole purpose of the redundant well.

Q. Step-rate tests. I believe you testified about the step-rate test. I apologize if you said this already, but I didn't hear. What was the fracture pressure break-over?

A. We didn't reach it. When we did the step-rate test. I mean --

Q. What was the highest pressure that you got to?

A. I'm trying to recall right off the top of my head, Commissioner Warnell. I believe it was about 3,500 pounds, bottom-hole pressure.

Q. Okay.

A. But I just can't recall exactly.

Q. And I believe I saw in your well sketch diagrams that the casing is set all the way to TD and then perforated?

A. Yes, sir.

Q. It's not an open-hole completion?

A. That is correct. It is not. And we would determine that on the basis of the logs and the coring that we would do of the zone when we drill the well.

Q. So will you be coring as you drill or sidewall cores?

A. We'll do sidewall cores after we pick core points based on the formation microimaging and the other logs.

Q. I believe you testified that you may or may not line the tubing depending whether it's wet or dry?

A. That is correct. I mean, the intent is to have the line tubing, and we may choose to keep it that way even if it is a dry well just to provide added protection. But in a dry well, it's not really necessary.

Q. It's not necessary, but it does give you the flexibility, if it was in the order?

A. Yeah. And in this particular well, very frankly, it's probably not likely that we would go -- even with a dry well, that we would not line it. Because my concern -- and I would communicate that to my client -- is that while it is not likely that we would have a problem, if we are assured that we can maintain that phase, that super-critical phase in the tubing, if for some reason the injection pressure dropped or during start-up or shutdown of the well, we had conditions that were transient in that tube, if you have the lining, then you're protected no matter what, even if do you have some free water coming out.

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

CHAIRPERSON BAILEY: Commissioner Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I have a couple of questions, Mr. Gutierrez. Good morning.

A. Good morning.

Q. The current saltwater disposal well, is that injecting under pressure?

A. It is.

Q. What's the, kind of, current pressure regimen of the proposed injection for the AGI?

A. For the current surface water pressure that they're injecting?

Q. Would you characterize it as overpressure? Underpressure?

A. Oh. I would characterize it as normally pressured.

Q. Normally pressured?

A. Yes, sir.

Q. For your -- you referenced three other combined

AGI and saltwater disposal wells --

A. Yes.

Q. -- combined wells?

How are they handling the two different waste streams on those wells? Are they doing slugs of water or slugs of CO_2? Are they commingling at the surface? Commingling at the bottom?

A. Excellent question. In general, they're commingled in a mixing chamber at the surface, because you've got the TAG up to a certain pressure, which is what it takes to make it super-critical, and then you pressurize the water sufficiently. You put those in a mixing chamber, and then it goes down the well.

However, interestingly enough, to use a very specific example to give you an idea, Targa was doing exactly what you just said. They were injecting TAG, but then they would occasionally -- not occasionally, but, you know, they wouldn't always inject water, and they would not always inject the same amount of water. Okay? Well, several years ago, as a result of that mode of operation, they were seeing very dramatic fluctuations in the pressure on the back side of the tubing. Okay? Because obviously when you're injecting just TAG, the tubing gets hotter. You also have a higher injection pressure. You have a little more ballooning of the tubing. And then when you're injecting with water, you have the exact opposite situation.

So they actually were getting such fluctuations that when they showed that information -- well, they internally looked at it and were confused by it. They talked to us and to E. L., when he was the district director down in Hobbs, about it, and he said, I don't think you can really tell whether you have a problem or not. We need to do an MIT on the well and go check it out.

So we did that, and we found that -- did MITs on the well both when it was running wastewater only, when it was running a mixture of wastewater and TAG and when it was running TAG only. And what we found is exactly what I thought was going on, which was that really there wasn't -- there wasn't any kind of a tubing leak or a packer leak or anything else. It was just these fluctuations on the back side.

So as a consequence of that, I recommended -- and my understanding is that that is what they have continued to do for the last couple of years -- that they -- instead of putting in as much water as they could put in when they had a lot of water or whatever, that they have enough storage capacity on site that they could just regulate the wastewater disposal into the well so it was just a constant ten gallons a minute of wastewater going in with their TAG. And when they started doing that, it eliminated these fluctuations on the back side that were -- that were confusing the issue before.

So that is the -- those are the operational issues that arise with a wet well, and I think that those are the kinds of things that is driving DCP to want to have a dry well if at all possible, because it's a different operating regime.

Q. Right. So if they do operate as a combined well, it would be mixing, presumably, at a steady rate, as you mentioned?

A. That's correct. Because as a matter of fact, right now they are not injecting saltwater into their SWD at a constant rate. They inject the water as they get it, or in some cases, as Russ mentioned, they may get a slug of liquids, hydrocarbons and water that comes from a gathering system and gets put into their plant system. So when that happens, they get a little increase in the water volume, or in the summer, they get an increase in the water volume because their cooling towers have to blow down more often. So they have not been injecting at a constant rate. But that would be something that would be different if they were using this as a combined well.

Q. As in your other applications that we've seen, your calculations are purely volumetric and don't take into account any chemistry or CO2 soluble water, mineralization, etching of carbonates, nothing like that?

A. No, nothing like that. Yes, sir.

Q. That would make your estimates conservative?

A. I'd say very conservative, yes.

Q. I always ask the same question.

With your porosity zone -- high porosity zone to the southeast of your location -- I'm also looking at the cross section on Figure 12 in Exhibit 1.

A. Yes.

Q. And I think that cross section is drawn on Figure 18.

A. Figure 12? Is it Figure 12?

Q. Figure 12 is the cross section.

A. Right. Yes. That's right.

Q. Is that the trace of the cross section on Figure 18?

A. Yes, it is.

Q. I know you have a limited depth control in the area. And I'm looking at your porosity map that's

Figure 10 in Exhibit 2.

A. Yes.

Q. How did that map come about? Where did you get the porosity?

A. Of course we used the logs that you saw in the cross section, but we do have other logs that are available. For the wells that penetrated that zone outside of our detailed area of investigation, we got those from his, from Petra, and then so we did it on that basis.

Q. Okay. Is there any justification for relating that porosity to any structural elements?

A. Well, there appears to be a slight -- I can't even say for sure. There appears to be a slight sag in that area, but it really is more, I think, a diagenetic effect.

Q. Diagenetic?

A. Yeah.

Q. Sometimes with these reformations, you get incised canyons, and then those noses have higher energy.

A. Yes. But we haven't -- I haven't really seen that here. It just appears to be a lesser degree of filling with dolomite and anhydrite from what I could see.

Q. So purely --
A. Yeah.
Q. I believe those are my questions. Thank you.
CHAIRPERSON BAILEY: I understand that our counsel has some legal questions concerning notice?
MR. BRANCARD: Yes.

CROSS-EXAMINATION

BY MR. BRANCARD:
Q. Mr. Gutierrez, I just wanted to clarify something. Throughout the application, you are required to calculate various radii here, whether it's the injection plume, it's the wells you're looking at within a half mile, the notice within a mile, correct?
A. Yes, sir.
Q. And in each of those cases, if I -- I want to clarify. In each of those cases, your center point is the bottom hole of the injection zone?
A. Yes, sir.
Q. If you look at Figure 9 on your presentation --
A. Oh. Figure 9 on the presentation.
Q. Yes.
A. Sorry. I'm sorry. I went to slide nine instead of Figure 9.
MR. RANKIN: I think it should be page 30.
MR. BRANCARD: Yes.

Q. (BY MR. BRANCARD) Am I reading that correctly? Is there not about a 670-foot horizontal difference between the top of your injection zone and the bottom of your injection zone?
A. That's correct. That's correct.
Q. Did you in any way incorporate that 670-foot distance into your calculations of where the location of the injection plume is, which wells you're looking at and where you gave notice to?
A. No, not really, because what we -- first of all, we don't really know that we would use that entire injection zone, but we used the basal portion of it. We skewed it towards that end because of basically two reasons. One is that we believe the better portion of the reservoir will be in the lower part of that zone, so it may be within about 2- or 300 feet of where the bottom-hole location is. But we used a one-mile radius rather than -- what, for example, the new regs would require would be a half-mile radius relative to the distance that is likely to be affected by the plume, if you calculate it to be under a half mile, which it was well under a half mile here.
Q. Okay. Flipping to the application -- do you have that in front of you?
A. I do.

Q. -- Figure 13 -- it's like page 18 or something.

A. Yes.

Q. Okay. There are two radii -- there are two circles here. Okay? Are those calculated based on: One, the top point of injection, and the other, the bottom point of injection?

A. That's correct, even though we weren't -- yeah. We didn't call them out that way, but that's essentially what it is, yes.

MR. BRANCARD: I'm just raising -- I mean, we have a unique situation -- well, not completely unique, but a different situation here where we have a deviated injection well, and, therefore, we have a difference between the top and the bottom of the injection zone. So I just want to bring that up to the Commission, about whether you're comfortable that an adequate analysis has been made of the half-mile zone for other wells and adequate notice has been prepared here.

CHAIRPERSON BAILEY: We always have to be concerned about that.

MR. RANKIN: If I might just interject? My understanding is the existing rule is a half mile from the bottom hole. In this case we provided a mile notice. So, therefore, it would have incorporated any of that 670-foot difference. So that's part of the reason why I wanted to make sure that was clear in testimony.

RECROSS EXAMINATION

BY COMMISSIONER BALCH:

Q. If I could follow up briefly on your Figure 13. I guess it's also Figure -- couple of slides back -- or forward, same figure he was referencing in Exhibit 1. Do you have that in your slide show as well?

A. Yes.

Q. Right to the east -- I'm sorry -- west --

CHAIRPERSON BAILEY: It's Figure 10.

Q. (BY COMMISSIONER BALCH) The Figure 10 presentation -- Figure 10 in Exhibit 1, there is one well location just outside the circle to the west. Do you see the well I'm talking about?

A. Directly west -- is it this well here you're speaking of (indicating)?

Q. That's the one.

A. Yes, sir.

Q. What can you say about that well? Is it a shallow well?

A. It is. It's above the injection zone, but I think it's a Grayburg well. Let me go back to another figure. Let me just get to that.

It is this well right here (indicating). It is a clean well. It's well above the injection zone, well above the caprock.

Q. Right. So while the upper circle would include that well, it's not going to be a factor for safety?

A. It wouldn't make any difference.

Q. Thank you.

CHAIRPERSON BAILEY: My turn.

CROSS-EXAMINATION

BY CHAIRPERSON BAILEY:

Q. You also were the authority instrumental in permitting the AGI #1 well, weren't you?

A. No. That's the one well I didn't permit.

Q. The one you didn't?

A. That's right. And ironically -- you know, I mean, I have to say this. Because of the initial difficulty that DCP encountered when they started injecting into the #1 well, which was a higher-than-anticipated required pressure to get into that well because the Devonian is not the world's best reservoir, as a result of that is the reason why we were hired in 2005 to identify the Linam location rather than -- I don't think that -- in my own opinion -- and I'm not questioning what was done in the past, but in my own opinion, if I had been tasked with looking for an AGI reservoir at this location, I would never have picked the Devonian to begin with, because I just think it's a tricky zone to deal with in terms of its predictability about how good a reservoir it is. So consequently, when we were asked to look at this, we looked at the other zones other than the Devonian.

Q. What is the injection rate that was allowed for the #1 well?

A. There was no rate limitation at all. When the well was originally permitted, it was anticipated that the plant would be producing somewhere in the neighborhood of about 1.2 to 1.5 million cubic feet a day of acid gas. When they added the second compressor there, it allows them to reach their full 90 million cubic feet a day processing capacity, which would result in about 2 million cubic feet a day of acid gas, which is currently what the plant is producing approximately and what it would be producing and injecting into the #2 well.

Q. So there would be no issues connected with pressures or rate between the two wells and switching back and forth between the AGI #1 and the AGI #2?

A. Well, the AGI #2 is going to take a greater pressure to put in the same amount of volume than it would it from the AGI -- I'm sorry. The AGI #1 will require a greater pressure to -- surface pressure to accommodate the same volume that the AGI #2 will simply because it's a deeper well, but it also has -- the MAOP for the AGI #2 well is about 3,100 psi at the surface. Currently their injection is running about 2,100 psi at the surface. They could never even make 3,100 psi at the surface.

But as I mentioned, in the AGI #2 well, we anticipate that the MAOP would be 1,700 and that they would probably be injecting more in the 1,200 psi range.

So basically yes, there essentially has to be pressure control in the -- in the line so that -- and this is incorporated into all of the AGI wells, that we have a pressure-control valve that does not allow the MAOP, and it kicks off before the MAOP is reached in either of the two wells. But yes, there is going to have to be higher pressure to inject into the #1 well than the #2 well.

Q. So there would have to be operational accommodations if there are -- if there is any switching between the two wells or simultaneous?

A. Absolutely. Absolutely. And that basically is pressure-reducing valves.

Q. The silt buildup in the saltwater disposal well that you have seen, will that create any problems for plugging that well?

A. No. It'll have to be -- we will have to muck that stuff out before we perforate and squeeze into that zone.

Q. It should not prevent adequate plugging?

A. No, absolutely not.

Q. You talked back and forth; you want to have both wet and dry?

A. Yes.

Q. When will that decision be made as to whether or not you are going to go one way or the other?

A. I would expect the decision to be made within the next six months. If we have -- I think we have located -- I briefly spoke to Mr. Goetze during the break, that I believe we have identified a zone that we may be able to permit for saltwater injection. But we haven't gotten there yet. But I anticipate that within the next six months we'll have either identified an adequate alternative zone that can be used, whether it is through drilling a new well or acquiring an existing well in the area, a shallower well. And if that is permitted by the state, then we would be able to go strictly to a dry injection. If that's not the case and we can't find an adequate reservoir that could be permitted as a separate saltwater injection zone, then I would anticipate that decision to be made within the next eight months, six to eight months, something like that.

Q. Those are my questions. Thank you.

CHAIRPERSON BAILEY: Do you have any --

MR. RANKIN: Nothing further.

CHAIRPERSON BAILEY: -- redirect?

All right. You may be excused.

Does that conclude your case?

MR. RANKIN: That would conclude our case, Madam Chair. Thank you very much.

MR. WADE: The OCD would call Mr. Phil Goetze.

PHILLIP R. GOETZE,

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

DIRECT EXAMINATION

BY MR. WADE:

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

A. My name is Phillip R. Goetze.

Q. And who are you employed by?

A. I am employed by the New Mexico Oil Conservation Division, Engineering and Geologic Services Bureau.

Q. What do you do at the Bureau?

A. Primary assignment has been reviewing applications for injection, including saltwater disposal, waterfloods, pressure maintenance projects and also have included review of the acid gas injection permits.

Q. And have you testified regarding previous acid gas injection permits?

A. Yes. I've had one opportunity.

Q. In that opportunity, were you qualified as an expert in the technical review of AGI application?

A. I presented my credentials, and the Commission accepted them.

MR. WADE: And, Madam Chair, I'd move again to qualify Mr. Goetze as an expert on technical review of AGI applications.

CHAIRPERSON BAILEY: He is accepted.

Q. (BY MR. WADE) Regarding this application brought today, have you had a chance to review it?

A. Yes, I have.

Q. And without getting into details, did you find the application approvable with the OCD's proposed conditions and the later modifications as discussed between the OCD and DCP?

A. Yes, I do.

Q. And referring to the conditions -- do you have the pre-hearing statement with you -- the OCD's pre-hearing statement with you?

A. Correct, I do.

Q. Is that where the modifications are found?

A. That is where we thought the amendments would be added.

Q. Initially?

A. Correct.

Q. You heard Mr. Gutierrez discuss certain conditions that were modified, and those were conditions to 6, 7, 12, 13 and 14. As to the remaining conditions, are those conditions that were accepted in a previous application?

A. Correct. They were submitted and accepted.

Q. By the Commission?

A. By the Commission.

Q. Did you find that Mr. Gutierrez' testimony was an accurate reflection of what was discussed between DCP and OCD regarding the conditions that were modified?

A. Correct.

Q. Is there anything you want to add to those?

A. At this point, no, I don't have any additions.

Q. And, again, those proposed modifications are acceptable to the OCD?

A. Correct.

Q. Based on your review of the application, the C-108, and the conditions that the OCD proposed and modifications to some of those conditions, does the OCD find that the application is protective of fresh water, human health, safety and correlative rights?

A. Based on what was provided, it is.

Q. And would you recommend to the Commission that the application with the conditions and modifications be approved?

A. I believe it is capable of being approved as presented.

Q. I don't have any further questions.

CHAIRPERSON BAILEY: Do you have any cross-examination?

MR. RANKIN: None, Madam Chair. Thank you.

COMMISSIONER WARNELL: No questions.

CHAIRPERSON BAILEY: Commissioner?

COMMISSIONER BALCH: I have no questions.

CHAIRPERSON BAILEY: I have one.

CROSS-EXAMINATION

BY CHAIRPERSON BAILEY:

Q. Are these the same and is this a complete list of all of those conditions that we have been applying to acid gas injection wells that have come before the Commission since you have been here?

A. I reviewed the previous applications and the conditions that were applied and copied or referred to them as the same conditions I've included here as part of my testimony and my supplemental request to the Applicant. So yes, they are the same list that we've used previously in our review process.

Q. That's all I have.

CHAIRPERSON BAILEY: Do you have any other questions?

MR. WADE: No other questions.

CHAIRPERSON BAILEY: All right. You may be excused.

THE WITNESS: Thank you.

MR. WADE: OCD has no further witnesses.

CHAIRPERSON BAILEY: Okay. Do we have any closing statements?

CLOSING STATEMENT

MR. RANKIN: Madam Chair, we would ask that DCP's application for its Artesia AGI #2 be granted in accordance with the C-108 that was provided with the application, and then, of course, with the conditions that were presented by the Division and modified by agreement of the parties, and we would so request.

CHAIRPERSON BAILEY: Okay. Do I hear a motion from the Commissioners to go into closed session in accordance with New Mexico Statute 10-15-1 and the OCC resolution on open meetings?

COMMISSIONER WARNELL: I'll make that motion.

COMMISSIONER BALCH: I will second.

CHAIRPERSON BAILEY: All those in favor?

(Ayes are unanimous.)

CHAIRPERSON BAILEY: We will go into closed session where we will deliberate this case and only this case, and I expect it will then be lunchtime. I would hope that we would be able to come back into session about 1:00.

(Commission in closed session, 11:32 a.m.; break taken, 11:32 a.m. to 1:01 p.m.)

CHAIRPERSON BAILEY: The Commission has been in closed session since 11:30. Do I hear a motion for us to come back out of closed session?

COMMISSIONER BALCH: I have a motion.

COMMISSIONER WARNELL: I second that motion.

CHAIRPERSON BAILEY: All those in favor say aye.

(Ayes are unanimous.)

CHAIRPERSON BAILEY: The only thing discussed was Case 15127. We have reached a decision on this, and we would like for our attorney, Bill Brancard, to give us a summary of what the order should be.

MR. BRANCARD: Thank you, Madam Chair.

The Commission proposes to approve the application to inject acid gas and carbon dioxide at the Artesia AGI Well #2 in the location and depth and under the specifications set forth in the C-108 application. This approval is with the conditions submitted by the Division in its pre-hearing statement, as further modified today under the agreement between the Applicant and the Division.

Further, the Commission conditions this approval with the condition that the Applicant plug the saltwater disposal well at the facility properly and that the Applicant update the existing H2S plan for the facility.

Did I correctly characterize it?

CHAIRPERSON BAILEY: Yes. That H2S contingency plan must be approved before operations begin -- or injection begins on the AGI #2.

Mr. Rankin, will you prepare a draft order?

MR. RANKIN: I would be happy to, Madam Chair.

CHAIRPERSON BAILEY: Okay. Our next meeting date is July 17th, so if you could have that order sent to our Commission counsel, Bill Brancard, in plenty of time for his editing and our review.

MR. RANKIN: Be happy to.

CHAIRPERSON BAILEY: Thank you.

Do you have a date certain that you would like for that, Bill?

MR. BRANCARD: A week before will be fine.

CHAIRPERSON BAILEY: Is there any other business before the Commission today?

Hearing none, then I will hear a motion to adjourn for the day.

COMMISSIONER WARNELL: I make the motion to adjourn.

COMMISSIONER BALCH: Second the motion.

CHAIRPERSON BAILEY: All those in favor say aye.

(Ayes are unanimous.)

(The proceedings conclude, 1:04 p.m.)

STATE OF NEW MEXICO

COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, 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.

Mary C. Hankins

MARY C. HANKINS, CCR, RPR
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