STATE OF NEW MEXICO

ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

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

CASE 15528

APPLICATION OF DCP MIDSTREAM, LP, FOR AUTHORIZATION TO INJECT ACID GAS INTO THE ZIA AGI No. 2D WELL LOCATED IN SECTION 10, TOWNSHIP 17 SOUTH, RANGE 32 EAST, LEA COUNTY, NEW MEXICO

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

Thursday, August 25, 2016

Santa Fe, New Mexico

BEFORE: David Catenach, Commission Chairman
Dr. Robert Balch, Commissioner
Patrick padilla, Commissioner
Cheryl Bada, Esq., Legal Examiner

This matter came on for hearing before the New Mexico Oil Conservation Division on Thursday, August 25, 2016 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.

REPORTED BY: Mary Therese Macfarlane
New Mexico CCR 122
Paul Baca Court Reporters
500 Fourth Street NW, Suite 105
Albuquerque, New Mexico 87102

APPEARANCES

FOR THE APPLICANT:

Adam G. Rankin, Esq.
Holland & Hart
P.O. Box 2208
Santa Fe, NM 87502-2208

FOR NEW MEXICO OIL CONSERVATION DIVISION:

Keith Herrmann, Esq.
Asst. General Counsel
1220 S. St. Francis Drive
Santa Fe, NM 87505

C O N T E N T S

INDEX OF EXHIBITS

(Time noted 12:52 p.m.)

COMMISSIONER CATENACH: At this time I will call the meeting back to order. And the next order of business today is the Application in Case No. 15528, which is the application of DCP Midstream, LP, for authorization to inject acid gas into the Zia AGI No. 2D well located in Section 10, Township 17 South, Range 32 East, Lea County, New Mexico.

Call for appearances in this case.

MR. RANKIN: Thank you, Mr. Chair. Adam Rankin on behalf OF DCP Midstream, LP. I have two witnesses today. I would like to make a short opening statement after entry of appearance for counsel for the Division.

MR. HERRMANN: Mr. Chairman, Keith Herrmann representing the Oil Conservation Division. The Oil Conservation Division just has one exhibit we would like to submit at this time. It's our Division geologist's view of the Application, and the author of the exhibit will be here for examination if the Commission so desires, but otherwise we will not be presenting any testimony.

COMMISSIONER CATENACH: Okay.

MR. HERRMANN: So this is marked as OCD Exhibit 1, and I believe it will be also referenced in Mr. Rankin's testimony -- or presentation.

COMMISSIONER CATENACH: Who is your division representative?

MR. HERRMANN: Mr. Philip Geddes.

COMMISSIONER CATENACH: And he's also going to be the seismologist?

COMMISSIONER BALCH: Has he been certified as an expert in --

Mr. HERRMANN: Yes, he has, and yes, he is.

COMMISSIONER CATENACH: Okay.

COMMISSIONER PADILLA: It's going to be that kind of afternoon.

COMMISSIONER CATENACH: Okay. Is there any objection to the admission of NMOCD Exhibit No. 1?

MR. RANKIN: No objection, Mr. Chairman.

COMMISSIONER CATENACH: MMOCD Exhibit 1 will be admitted as evidence in this case.

And, Mr. Rankin, proceed.

MR. RANKIN: Thank you, Mr. Chairman. I'd just like to make a short opening statement.

We will have two witnesses today, one fact witness and one expert witness who will be supporting the technical components of the C-108 application. The first witness will be Mr. Canfield. He will present fact testimony and the background of the Zia 2 gas plant and it's AGI operations, as well as the benefits and the importance of the proposed AGI No. 2D well.

Our second witness will be Mr. Alberto Gutierrez of Geolex, Incorporated. He will be our technical witness, providing technical and expert testimony supporting the C-108 Application.

Before we proceed through that presentation I would just like to give a little bit of background, an overview of the summary -- summary of our presentation, which I think will help put into context the application and the history here.

First, Order R-13808, which was issued by the Commission in 2014 authorizes DCP to inject treated acid gas into two wells, the Zia AGI No. 1 and the Zia AGI No. 2 into the Brushy and Cherry Canyon formations. Under that Order DCP has been injecting treated acid gas since August of 2015. It has not yet drilled the No. 2 well, which has been authorized, and before it had an opportunity to drill that No. 2 well DCP was approached by Concho Resources with a request to reevaluate the deeper Devonian and deeper formations for potential as an injection zone, and to determine whether or not those zones would serve potentially as a zone for injection of the treated acid gas.

DCP had previously evaluated the Devonian when it was first considering the AGI wells for the plant but did not have enough, sufficient data to confirm or properly evaluate the suitability of that formation in that area as an injection zone. Since Concho had approached them, the new data had been available. Concho itself had drilled a salt water disposal well in the Devonian, and DCP was able to review some seismic data in that area. So with that review and the addition of the well that Concho had drilled, DCP was able to reeavaluate the suitability of the Devonian and deeper formations for injection.

Now, as a consequence of that reevaluation DCP has put off for some time drilling of the second well, so at this time it's now important that DCP proceed to drill a second well, and having made the determination that the Devonian and the deeper formations immediately below are suitable, we request that we have an authorization to inject into those formations and that we have -- be able to expedite that Order, assuming it's agreeable with the Commission.

And you will hear testimony today that addresses the prudence, the plant -- issues addressing plant reliability and the fact that the second AGI well is the expectation of the existing air quality permit. So it's not only prudent but necessary for DCP to operate with two AGI wells.

And you have heard testimony to that effect in the past, and we will briefly give a summary again today.

In addition Mr. Gutierrez will address -- you will hear that the C-108 is approvable, that it protects all ground water sources, that the application protects human health and the environment by reducing emissions, and the proposed injection well will prevent waste and protect correlative rights of adjoining producers.

If the proposed AGI 2D well is approved and is proved to be successful, the existing AGI No. 1 well, which is currently in operation, would remain as a redundant or secondary well, giving DCP operational flexibility and additional capacity to serve the producers in the area.

But for now DCP needs to maintain the existing already-authorized injection into both the AGI No. 1 and AGI No. 2 into the Cherry and Brushy Canyon formations, as approved in Order R-13808, and in order to ensure that if there are any issues with this proposed 2D well they have an authorization for injection for those two wells. They have already the preexisting.

That way we can be assured of having that redundant capacity.

Before moving on to the witnesses, I would like to address two housekeeping matters, if I might, real quick.

We would ask, DCP asks that we be permitted to submit a proposed Order early next week outlining the facts and the conditions that have been recommended and suggested by the Division, so that we may have an opportunity for the Commission to consider that order at its next hearing on September 6, and the reason being, as you will hear today, that DCP has an opportunity and intends to proceed to drill the well in late September or October.

DCP also has one additional exhibit that we would like to present that came in after the Prehearing Statement was filed, and it relates to the provision of Notice, and so at that time I will present that additional exhibit with permission to do so.

That is all I have right now, and I would like to call our first witness, Mr. Canfield.

(Note: Whereupon the presenting
witnesses were duly sworn.)

MR. RANKIN: Mr. Chair, I just was advised that I made a misstatement in my opening statement. I misstated the Order number that authorized the AGI No. 1 and the AGI No. 2 wells. It should be 13809 is the correct Order number, not 13808. I apologize.

CARLTON DANA CANFIELD,

having been previously sworn, testified as follows:

EXAMINATION

BY MR. RANKIN:

Q. Mr. Canfield, will you please state your name for the record.

A. Carlton Dana Canfield. I am also known as Tony.

Q. Where do you reside?

A. In Midland, Texas.

Q. And by whom are you employed?

A. DCP Midstream, LP.

Q. How long have you been an employee of DCP Midstream?

A. Thirty-five years.

Q. Will you please give a brief review of the different jobs you have held for DCP.

A. I've held various operational and engineering jobs, middle management jobs. My most recent is project engineering manager, working in corporate for large projects.

Q. And what are your job responsibilities in that role?

A. Project engineering manager, I generally take projects after the initiation phase, where they have selected a location, say for a plant, and I work on the final design, working to select the contractors, ordering equipment, and basically executing the project through completion and commissioning.

Q. What is your familiarity specifically with the Zia 2 gas plant and the AGI wells there?

A. Zia 2, the plant itself was my project and so I spent the last two years building that facility. I was familiar with the AGI on the periphery; there was another project manager responsible for that. But that injection well is on the plant site so I'm relatively familiar, particularly with everything upstream of the well itself.

Q. So you're familiar with the integrated nature of the AGI wells to the operation of the Zia plant?

A. Yes, sir.

Q. Just briefly, what is DCP's business in Southeast New Mexico? What services does it provide?

A. We are a natural gas gatherer, processor and marketer. We have about a dozen processing plants between West Texas and New Mexico, and thousands of miles of gathering lines, and 100 to 150 booster stations in that area.

Q. Now today -- you're an engineer, but you're not testifying as an expert, you're testifying as a fact witnesses; is that correct?

A. That is correct. As a fact witness.

Q. Mr. Gutierrez will be testifying as the expert on the C-108 and the technical aspect of the C-108 application.

A. That is correct.

Q. Are you familiar with the C-108 application that was filed on behalf of DCP?

A. I am.

Q. And have you prepared slides to help assist you with your testimony today?

A. I have.

Q. Okay. And I see you are already on the slides.

These are slides that are identified in what has been marked as Exhibit No. 1 in the notebook next to you; is that correct?

A. That's correct.

Q. Mr. Canfield, let's go ahead and proceed.

Will you please tell the Commission about the Zia gas plant's operations and give a bit of a brief overview of the facility.

A. The Zia Gas Plant is a 200 million a day cryogenic gas plant located between Hobbs and Carlsbad that was started up in August of 2015. That facility consists of the processes within it, which include the gas receiving, in which basically we segregate any liquids, hydrocarbons or waters that fall out in the pipelines, and the gas that comes into the plant. We take the gas, compress it up to about 900 pounds, go through an amine system where we separate out To remove the H2S And CO2 from the gas. The natural gas proceeds into the cryogenic plant where the NGLs are extracted. The NGLs go on in the pipeline down to -- I think most of them end up down in the ship channel area in fractionation. The residue gas we sell to transmission lines for residue gas transmission.

The H2S and CO2 that's removed from the amine system are compressed, and those are injected right now into the AGI No. 1 in the Brushy and Cherry Canyon Zones.

So from that perspective the AGI and that system is an integral part to the facility.

Q. And now would you explain to the Commission why it is that DCP is seeking now at this time authorization to drill and inject through the 2D into the deeper Devonian Formation.

A. Yes. As previously mentioned, the AGI-2 was permitted. It was not drilled. At the time we got done with the AGI No. 1, Concho approached us and requested we consider the Devonian. They have production above and below the Cherry and Brushy Canyons, and they had concerns about drilling through that formation in future years as that zone would pressure up, and they felt that the Devonian would be an adequate reservoir to inject in.

They have good experience with the Devonian. They have salt water disposal wells in those, and in point of fact we've been working with Concho in the design of the well drilling and completion.

So we've been -- I wouldn't say partnering quite with them, but working closely with them on the well.

We did review of the Devonian, and it appears to have good reservoir characteristics for acid gas injection. Since it appears to be a strong injection zone, we believe it will provide a good long-term service for both us and our producers, particularly as gas production and related sour gas volumes increase it's going to be a preferential zone to inject into.

In addition to good reservoir characteristics, it is of course situated below any known production in that area, so it reduces the overall risks associated with producers.

Q. And that's because the producers would not have to drill through a zone that was primarily being used for acid gas disposal?

A. That is correct.

Q. Because the Devonian is deeper than those formations.

A. That is correct.

Q. Now, in my question and in your answer we both were referencing the Devonian Formation, but in fact the application identifies three formations to inject into.

A. That's correct. The Devonian, the Fusselman and the...

Q. Is the Wristen the third?

A. Yeah, the Wristen.

And Alberto Gutierrez will, I dare say, get into those in some detail.

Q. When we reference the Devonian we are speaking of all three of those?

A. That's correct. When I refer it to I refer to that entire three zones, three formations, as the Devonian zone.

Q. So on your next slide, Mr. Canfield, will you address for the Commission some of the benefits that DCP expects to realize from the AGI No. 2D well and from the integral operations with the Zia Gas Plant.

A. Certainly. As stated before, the AGI system and the injection wells are an integral part of the facility. They have to be there in order for the facility to operate.

Further, as mentioned before, the air

permit requires the acid gas injection. It's part of the Prevention of Significant Deterioration PSD permit that we have, so the AGI is necessary for the plant to operate under that permit.

The AGI is also considered best available control technology, BACT. It is used in lieu of what maybe historically was a typical system of sulfur recovery gas incinerator. The AGI is actually going to have lower emissions due to the fact it is sequestering all of the acid gas, as opposed to an SRU and tail gas which has some level of deficiency and still has some SO2 emissions associated with a tail gas incinerator.

Zia II Plant and the associated AGI have resulted in a net reduction of emissions from DCP facilities in the Southeast New Mexico area, as a result of consolidation of some facilities and shutdown of other facilities that were less efficient, on the order of about 800 tons per year in criteria pollutants.

The AGI has been injecting into that zone since the plant started up in August of '15.

Q. On your next slide you address some additional benefits, not just to DCP but to the industry as a whole. Would you review for the Commission those additional points.

A. Yes, sir.

From a commitment level, since 2014 DCP has spent approximately $480 million on the Zia II program, but it included the Zia II plant, the acid gas well, and associated infrastructure gathering systems and other infrastructure projects in support of the producers in the area. These projects have produced a substantial incremental increase in gas-processing capacity in the area. And with respect to the to the AGI 2D well, DCP is willing to make the investment into that deeper Devonian Zone as the acid gas zone as part of our continued commitment to the producers in the area.

The 2D well is needed to service the current and future well production containing sour gas in that region. Also, the 2D well will provide redundancy for the existing AGI 1 well.

Q. Now, Mr. Canfield, you mentioned the word redundancy as a benefit here. Will you explain a little more about how the second AGI into the Devonian is a prudent investment that DCP values at this point.

A. Yes, sir. I'm going to go back to the PSD permit for a moment. That permit was based on the idea of redundancy for the acid gas injection system. In order to meet that intent, we have installed redundant compression, and we really need to have redundant acid gas injection wells in order to complete that intent of that PSD permit.

In addition, as part of continued commitment to our producers a redundant AGI system significantly increases the operative consistency and reliability of the entire facility. In that increased reliability of the AGI system reduces flaring for DCP as well as the producers, and it also basically sequesters the H_2S and CO_2.

Basically, in short, the AGI facility, of which the second well is going to be a critical component, reflects a prudent investment on DCP's part.

Q. How else does it affect reliability? Does it reduce downtime in the plant?

A. Absolutely. If you have redundant compressors, either of the compressors can handle the full load, and that's a big benefit if one unit either has scheduled maintenance or unscheduled maintenance. And with the AGIs we will have the flexibility if there is routine maintenance or any other issues with the wells that we can go into the one or the other.

So it's going to reduce downtime, provide higher operating consistency for the producers. It reduces emissions, of course, resulting from that downtime.

Q. What happens to the wells in the field if the Zia Gas plant is not able to inject wells -- treated acid

gas?
A. Well, normally they get shut in and/or they flare.
Q. So by having that redundancy it avoids having to flare those wells?
A. That is correct. And having the well also precludes us from having to flare that acid gas at the plant, too, from a maintenance standpoint.
Q. Now, on your last slide here, Mr. Canfield, let me just ask you: Does DCP request approval of the C-108 that was filed with the Commission, with the additional conditions that have been requested and recommended by the Division?
A. We do.
Q. And would approval, in your view, Mr. Canfield, benefit DCP and the state?
A. Yes, sir.
Q. Can you explain how, in what ways you view the addition of the 2D well to be a benefit to those other producers?
A. Yes, sir. If the deeper zone performs as we expect, we'll use that zone as the primary injection zone. Again, this reduces the producers' risk of drilling through the Brushy Canyon and Cherry Canyon zones.
The second well also provides the producers

a better operating consistency and reliability for both their acid gas system, as well as our plant.

From a New Mexico state standpoint, supporting protection of correlative rights and responsible development. It improves the reliability and safety of the AGI system at the plant. It improves cash flow to the state as a result of less shut-in gas, and reduces emissions due to producers and the plant flaring.

Q. Now, I mentioned in my opening DCP is requesting an expedited consideration of a proposed submitted Order.

Is that the case?

A. That is the case.

Q. Okay. And can you explain for the Commission why that is and what you're proposed drilling schedule is for the AGI 2D?

A. Certainly. DCP has full intent of drilling the second well, for all the benefits we have already discussed and in effect as part of the PSD permit. The delay -- the original intent was to drill right after the first well back almost a year ago, but the delay has been due to evaluating the Concho proposal.

The zone has been evaluated, and it looks like it's going to be the preferred zone. We don't see any value in delaying the acid gas injection well. We have been working with Concho. They do have a rig available October 18th, and we are driving towards that date in order to spud the well.

Q. In fact, Mr. Canfield, as the Zia Gas Plant ramps up to full capacity, isn't it a requirement under your permit to have a second AGI in operation?

A. It is. It is.

Q. So not only is it a prudent investment by DCP, but it's necessary under their air permit?

A. That is correct.

Q. Mr. Canfield, did you help oversee the preparation of the slides 4 through 7 that we just presented today?

A. I did.

MR. RANKIN: Mr. Chairman, I would like to delay admitting those exhibits into the record until after Mr. Gutierrez gives his presentation, and I will just move the admission of all the exhibits together, if that is okay.

COMMISSIONER CATENACH: Okay.

MR. RANKIN: Mr. Chairman, I have no further questions of the witness and would pass to the Commission or the Division.

COMMISSIONER CATENACH: Mr. Herrmann, any questions?

MR. HERRMANN: No.

COMMISSIONER CATENACH: Dr. Balch.

COMMISSIONER BALCH: I just have a couple of questions, Mr. Canfield.

EXAMINATION

BY COMMISSIONER BALCH:

Q. You have a redundant compression facility?

A. That is correct.

Q. Do they operate either one or the other, or do they operate simultaneously? Do they have variable drive motors that allow them to be efficient at different rates?

A. They operate individually, one at a time. They are not operating in tandem. Whether they could or not, I'd have to go back and review. They probably could if we wanted to, we could do A control system, but right now they are not set up to do that.

Q. So it's purely redundant.

A. 100 percent redundancy.

Q. The ZIA AGI No. 1 you just mentioned has been operating for a little more than a year. Has that had any downtime?

A. Uhm, the well itself I don't believe has had any downtime. The air -- the compressors once in a while for maintenance or other miscellaneous issues we've had some downtime, but I don't believe we have had well shut-in for any -- No. Even for the MIT well, didn't shut it in.

Q. Just basic maintenance and that's it.
A. Yeah, it's been going along.
COMMISSIONER BALCH: Those are my questions.
EXAMINATION
BY COMMISSIONER PADILLA:
Q. Mr. Canfield, just a couple.
Going back to that air quality permit, when you say that it's a requirement of the permit, is that due to capacity? As you ramp up to full throttle on the plant, you need to have that second well available in case of capacity issues?
A. Yes, we do. From the original design based on the PSD and the AQB, the original design had the intent of having two wells there.
I'm going to defer the capacity of that well, particularly the second well, to Alberto. He is going to be able to address the capacity of the wells better than I can.
Q. Just relating to air quality -- I mean aside from the well capacity, the injection capabilities, I'm wondering what ties that second well to the permit.
A. Reliability. What they don't want us to have is have a well down and us either flaring at the plant or producers flaring. So really the air permit is not an injectivity question, it's a reliability question and

reduction of emissions question.

Q. So do you currently have a waiver or something in the absence of that second well being on line for that permit, or an allowance?

A. I don't -- I'm going to have defer that question.

MR. RANKIN: I think I can help answer that question by another question.

FURTHER EXAMINATION

BY MR. RANKIN:

Q. Mr. Canfield, is the -- is the -- the requirement of the air permit is to provide a second well at full capacity?

A. That's correct. At full capacity of the facility.

Q. So it's only at full capacity that you're required to have that second AGI?

A. That's correct.

CONTINUED EXAMINATION

BY COMMISSIONER PADILLA:

Q. So as you are moving to full capacity, that is when the second well becomes essential.

And going back to the redundancy that Dr. Balch touched on, will this new Devonian become your primary? You're hoping that will be a better injection zone, or will you alternate the wells? What is your operational plan for the two wells, once this one is...

A. Our intent at this point would be to use the Devonian as the primary. Now, once we drill it and see what it is, you know...

COMMISSIONER PADILLA: Right. That's all I had, Mr. Chairman.

EXAMINATION

BY COMMISSIONER CATENACH:

Q. Mr. Canfield, did you mention the well cost? I thought I heard a number in there. The well cost to drill this well?

A. What I stated was that DCP has spent $480 million on the total program for Zia, which included building the plant, the AGI, as well as the associated infrastructure in order to support the plant.

Q. Okay.

A. I did not mention the well cost.

Q. Okay. You said you looked at other Devonian wells in this area. Is Concho on the Devonian, as well?

A. I'll have to defer that to Mr. Gutierrez.

Q. Okay. Just out of curiosity, how is -- the injection of this gas, is that charged back to the operators?

A. No. That's a strict cost to DCP. It would be the same as if we had a sulfur recovery plant, which was the previous technology. It's an absorbed cost.

COMMISSIONER CATENACH: Okay. That's all I have.

COMMISSIONER BALCH: One more follow up on that, if it's okay.

FURTHER EXAMINATION

BY COMMISSIONER BALCH:

Q. So a sulfur recovery unit potentially could make -- if the price of sulfur were to go up and you were using an SRU, then DCP would be the sole recipient of that profit. None of that would go back to the operator.

A. I have no clue how those contracts are set up.

Q. So my next point might also be a no-clue answer, then.

Similarly, if there were to be in the future some sort of credit for disposing of CO2, that would benefit only DCP.

A. I would presume at this point. Again it depends on -- you know, contracts change over time from a producer standpoint, as well as from our standpoint, so it's hard for me to predict.

Q. So maybe the better question is: The ownership of the gas that comes into the plant, once it reaches your gate is it solely the responsibility of DCP?

A. From a responsibility standpoint I would say yes. If it's an ownership question, that is dependent on the contracts that we signed with the producers. Some producers -- and I'm not intimately familiar with the contract base behind this facility. Some are percent proceeds. In history we have had take -- not take-or-pay, but they would take their own, take-in-kind. And I couldn't really tell you how our contract mix is done. I can get that information for you if you're interested, but I don't have that with me.

COMMISSIONER BALCH: I've got a lot of curiosity.

Thank you.

MR. RANKIN: Thank you, Commission. I have no further questions for this witness, so I would like to call our second witness, Mr. Alberto Gutierrez.

THE WITNESS: Thank you.

ALBERTO GUTIERREZ,

having been previously sworn, testified as follows.

EXAMINATION

BY MR. RANKIN:

Q. Mr. Gutierrez, good afternoon.

A. Good afternoon.

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

A. Alberto A. Gutierrez.

Q. Will you please tell the commissioners where you reside.

A. I live in Albuquerque.

Q. And your employer?

A. Geolex.

Q. What is your position at Geolex?

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

Q. What does Geolex do?

A. We are a consulting firm, geological engineering consulting firm with primary focus in environmental ground water and acid gas injection.

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

A. Yes, I have.

Q. Have you previously been qualified before the commission as an expert?

A. Yes, I have.

Q. Has that qualification included as an expert in petroleum geology, AGI operation and design, and hydrology and groundwater contamination?

A. Yes.

Q. And Mr. Gutierrez, did you yourself prepare the C-108 application that was filed with the Commission?

A. I prepared it in conjunction with others on my staff, yes.

Q. You oversaw the preparation and the submission of the C-108?

A. I did.

Q. Okay. And you did that on behalf of DCP?

A. That's correct.

Q. Did you also prepare any other exhibits for today's hearing?

A. Yes. I prepared this slide deck in conjunction with Tony. He worked on the earlier slides, and then the slides that are coming I prepared, yes.

Q. And there's a few other exhibits we will identify as we walk through your testimony?

A. Correct.

MR. RANKIN: Mr. Chairman, I'd like to tender Mr. Gutierrez as an expert in petroleum geology, AGI operation and design, hydrology and groundwater contamination.

COMMISSIONER CATENACH: Mr. Gutierrez is so qualified.

MR. RANKIN: Thank you, Mr. Chair.

Q. Mr. Gutierrez, you prepared a slide presentation for today's presentation; is that correct?

A. That's correct.

Q. Is that also identified in the exhibit packet by your side as Exhibit No. 3?

A. That is correct.

Q. Would you proceed to walk through your presentation with the Commission.

A. I will.

Uhm, I saw -- you know the weatherman in Albuquerque yesterday morning said this was Be Kind To Humans Week, so I'm going to try to keep my presentation as short as possible in keeping with that spirit.

But in all seriousness this is an important, very important project for DCP, and it's been a challenge, because when we originally started evaluating this area for acid gas injection and came up with the two wells which were previously approved, we evaluated the Devonian to the extent that we could, but we just did not have the data sufficient -- especially to be able to recommend in good conscience to DCP that they take the risk of drilling a well there, basically when the only well control we had was one plugged well that barely touched the top of the Devonian about .9 miles away, and then the other nearest well was the Concho salt water disposal well that is about two and a quarter miles southwest of the facility. So we just had no idea what the Devonian would do in that area, and we did not have any seismic data.

But subsequently, as Tony mentioned, when Concho approached us and said, "You know, we really would prefer that you guys use the Devonian. We've drilled in the last two years 10 Devonian salt water wells, we think we have a pretty good idea what that formation behaves like, and we think you have got some good options there."

We started a technical discussion. Lou Mazzullo from my shop, who is an expert on the Devonian, worked with Concho, and bottom line is that we were able to identify some data that were available, that we'll go through today, that were not available previously.

So in summary, what we would like to request is approval of the C-108 that was provided to the Division back in July. This Zia No. 2D is a significant improvement to the improved AGI system, and I think, for a number of reasons. One is because we believe based on what data we now have the Devonian would be a better reservoir, and it's also more agreeable to adjacent operators and to the regulators. The producers, as mentioned, would prefer not to have to drill through an injection zone, the injection zone that is currently approved for AGI No. 1 and 2; and Concho, being the primary leaseholder in the area, approached us with that concept.

And, you know, in terms of the timing, one of the good things has been is that while the AGI No. 1 has been in operation for approximately a year, since the full blend of anticipated acid gas has not yet materialized at the plant. What we have been injecting for the past year, instead of being about 10 percent H2S and 90 percent CO2, which is what we anticipate the ultimate mix will be, has been about 99.8 percent CO2 and 2 percent H2S. So there is hardly any H2S that's been injected yet, because since we haven't seen a lot of that coming in in the inlet gas. So it's a particularly good time, if we can find a deeper zone to inject into.

The benefits that Tony mentioned, protecting correlative rights and responsible development, the improved reliability, and added revenue to the State, and the reduced number of flaring events is really the key to why we want to do this.

So we would request approval of the C-108 as submitted.

I want to summarize the key aspects of that application now, if I could.

As Tony mentioned, we are proposing to inject into the Devonian and Silurian Formations, which are -- typically in Southeast New Mexico people just call them the Devonian, but really it's the Devonian, Wristen and Fusselman Formations, and they occur at this location at a depth of approximately 13,800 feet to 14,500 feet. And we would propose a maximum injection rate of 15 million cubic feet, which is -- by the way, we're not asking for any additional capacity. I want to make that very clear. The capacity that was approved for the No. 1 and No. 2 was 15 million, and we are not asking for anything more than 15 million, we're just saying that we may put the 15 million into the Devonian, if we can, instead of putting it into the Cherry Canyon and Brushy Canyon.

Using a safety factor of 100 percent, which has been our practice in evaluating these because we know that radial models are not perfect by any means but with the data that are available it's often what we can do, we see that the maximum extent of injection after 30 years would be a little less than 4/10 of a mile for 100 percent safety factor.

With respect to the potential for production in the area, there's no Siluro-Devonian production within at least three miles. And it's actually quite a bit more than three miles, but that is what I know I looked at very carefully.

There is a fair amount of salt water injection into the Siluro-Devonian in the general area, although the closest two wells are a little over two and a half miles away.

Within the area of review we identified 52 wells, if I remember correctly, within the one-mile area of review, and of those wells only a single well penetrated the very top of the Devonian. Only about 250 feet of the Devonian was penetrated in the Lusk Deep No. 2, which we will talk about a little bit. But it's a well that has been plugged. They tested the Devonian, it was wet, and they plugged it up back to the Morrow, produced the Morrow for some years, and now the well has been plugged.

So that single well is properly plugged and abandoned, and the proposed injection zones are well isolated from producing and fresh water zones.

The proposed injection zone is capable of permanently containing the injected fluid due to the low porosity and permeability of the caprocks above and below the zone, and we will look at those in more detail.

The real kicker of what allowed us to basically evaluate the Devonian is that with Concho's help we identified -- we had identified some seismic that was available that was owned by Devon, and through DCP's connections with Devon, it's a client of theirs, Devon was kind enough to allow us to analyze that seismic. They did not allow us to have the data or to present pictures of the data but we did spend an entire day with their geophysicists cutting and slicing the data and taking a look at it so we could identify better what was going on in the Devonian.

So the key elements of the C-108, as we talked about, is that it has some substantial environmental benefits in terms of the reduction of not only CO2 and SO2 emissions but also in particular the reduction of the criteria pollutant emissions that have resulted from DCP being able to consolidate their -- at least facilities, and close a lot of older facilities and have that replaced by the Zia plant.

It reduces waste and air emission by eliminating flaring due to shut-ins or failures that require wells to be shut in, and it is -- the nearby oil wells and water wells and surface water are going to be protected by the well design and the geologic factors, and importantly in this location the overlying Capitan Reef, which, while not being potable water is still protectable water as far as BLM is concerned. We made special provisions in the original Zia well and in this Zia 2D well to protect those resources.

The C-108 that you have presents all of the information needed to approve the installation of the well. It's been reviewed by the Division, and the Division's geologists and engineers and myself have discussed a number of issues relative to that, which we'll discuss a little later in terms of the conditions which we proposed and which also the Division proposed be conditions for permit.

Both the operators, the OCD, and the BLM strongly supports the project, in particular Concho as the adjacent operator. We obviously have not received any kind of protest of any kind, and the BLM is working with us to expedite an approval of the APD. I spoke to their engineer yesterday, and we anticipate we will have the APD approved even before a Final Order would be signed here in the first week of September. Of course if it's approved, if the APD is approved prior to the Commission signing the Order, they will probably put a condition in the APD that we have to have an Order from the Commission before we drill the well.

All of the operators have received proper Notice, and there have been no objections to the project. And we will go through the Notice issues in a little bit.

As we mentioned, the plant is located in Section 19 in Township 19 South, Range 32 East, the very west end of Lea County. This is a general location map that shows you where the plant and the AGIs are.

The overall site encompasses about 180 acres, the plant operations area alone about 50 acres. It's all BLM land. This is leased by DCP. The field gas gets sweetened, as Tony mentioned, by two amine units, and the TAG is then compressed and piped to the AGI wells.

All of the equipment is located within the fenced plant area, including the wells.

As I mentioned, the specific location of the well here is 1900 feet from the south line and 950 feet from the west line of Section 19. This is the same surface location that was approved for the AGI No. 2 in the Brushy Canyon and Cherry Canyon. The difference is, though, that that was to be an inclined well away from the other bottom hole location of the AGI No. 1 which goes to the north, and this well will be drilled as a vertical well in that same location, straight down to the Devonian.

So this is not an inclined well.

This is a picture, a little more of a blow-up of the site. You can see right now that up in this area right here is where the AGI No. I surface location is. This is the AGI No. 1 bottom hole location again in the Cherry Canyon, about 6,000 feet total depth, TDD. It's about actually 6500 feet of measured depth, because it's an inclined well.

The AGI No. 2 is 200 feet, is scheduled to be drilled 200 feet south of that well, and it will be a vertical well down to the Devonian.

So this gives you a little bit of the blow-up of the plant, and you can quickly see in this area here is -- the amine plant is in this area, and the amine contactors are in this area, and the TAG is then pumped low pressure to the acid gas compressors where it's compressed to high pressure. And then it would be -- it's pumped right now to the ZIA No. 1, and of course the ability would be to pump it to the Zia No. 2, which would be located up in this location.

Okay. So what is it that we are really talking about? We are talking about 10 to 11 percent H_2S and about 89 to 90 percent CO_2, plus some trace hydrocarbons in terms of the injection stream. We don't know exactly what this will end up to be. As I mentioned, currently it is almost all CO_2 we are injecting, but as those wells come on line we will be seeing more and more sour gas, and we anticipate this is closer to the mix that we will ultimately see.

We have determined that the injected fluid is compatible based on what we've seen of the formation fluid in the Devonian, and we've calculated an MAOP of 5,028 psig, although as you will see from our experience and our discussions with Concho, we anticipate the injection pressure to be much, much lower than that. Probably in the neighborhood of 12- to 1500 pounds at the surface.

The anticipated reservoir condition, it's a hot reservoir, probably 185 degrees average what we see, and you'll see where that data came from a little later in my presentation. At that temperature and about 6,000 psi, which is the bottom hole pressure that we anticipate in the reservoir, it's going to occupy about 6,000 barrels a day of space in the reservoir if the full 15 million were being injected. That would result in a radius of approximately .28 miles, and I'll show you kind of what that looks like in a radial model here.

Q. Just to interrupt. Uh, with respect to the area of review, our Prehearing Statement indicated there was a revised table that was to be replacing Table A-1 in the C-108 application. And that addresses the wells within the area of the review; is that correct?

A. Yes, it does.

Let me just kind of give a little background on that. And it's good time to do it right now when this slide is up, because one of the concerns that the Division expressed when they reviewed the application is that they wanted to have us go back and independently, independent from the data base of the Division, review the logs of these wells and be certain that we understood exactly what the TVD of all these wells within the one-mile area of review was.

We did that. We presented that. Originally it's table A-1 in the C-108, and then after our discussions with Phil and with Will Jones, we went back and reviewed that table again and actually pulled individual logs, and rather than just taking the TVDs or TDs from the data base, the OCD data base, we actually went back and confirmed it with log.

And we actually found that OCD's data base is pretty darn good, because there were only two wells that had different TDs. One well was about 200 or so feet deeper than it was shown in the data base when we went back to the logs, and then another well was about 1100 feet shallower than what was shown in the data base.

But the bottom line is that when we did that we submitted to the Division a revised table that is included as an exhibit here, and it corrects those two. And that table relates to all of the wells that are shown on this map.

Q. And that table, the revised table that should be replacing the C-108 table, that is marked as Exhibit No. 2 in your exhibit packet; is that correct?

A. Yes, sir, it is.

Q. And those indicate --

A. And let me just say for the Commission's benefit: Exhibit 2, you will note there are just two wells that have a note in bold, and those were the two that were found to be of different total depths. One the TD was 11,286 is what was listed in the data base and then it actually turned out to be 11,400 feet, and then one was listed in the data base as 10,858 feet, and it was 9179 feet actually.

Also in red on this table is the single well, the Lusk Deep Unit No. 2 which is the single well that was drilled in 1960 that penetrated the top of the Devonian, was plugged back to the Morrow, produced from the Morrow for some period of time, and then was plugged in 1971.

Q. With respect to that well, Mr. Gutierrez, does the C-108 include all the information required by the Division to approve applications, identifying wells that actually penetrate the proposed injection zone?

A. Yes. And we provided a plugging diagram of that well. The well was plugged back about 1470 feet. So basically they tapped into the top of the Devonian, found that it was wet, cemented back up to the base of the Morrow, and then produced from the Morrow for about a period of ten years, and then they plugged the well the rest of the way.

Q. Based on your review of the plugging information on that well, is it your opinion that that well is properly plugged and protective of hydrocarbon and groundwater resources?

A. Absolutely. And also it's located about almost a mile what way. It's about .88 miles away, to be exact.

That well -- I'll show you in more detail later, but that well is located right here. This is the Lusk Deep No. 2.

Q. And that's approximately .88 miles to the northeast?

A. That's right. It is in Section 16 of the Township up there in the southeast -- looks like the southwest of the southeast.

Q. And based on the modeling that you were able to do using the seismic data that you reviewed, is that well, in your opinion, in the path of the projected plume of the TAG at all?

A. No. I mean, it could be in the path over -- you know, if you just were injecting for an indefinite period of time, but over 30 years it certainly -- the plume is only estimated to go about .3 miles away, and this is about .88.

Q. Thank you, Mr. Gutierrez.

A. You know while we don't really have data to do any better than a radial model, what we do -- I had to think. I had to laugh about a parallel with Mr. Brooks I was hearing in the earlier testimony that he said as a lawyer he's got to do this. Well, as a geologist I've got to qualitatively look at the data and try to say: Okay. Where do I really think this plume would go, rather than just in a radial sense.

And from the seismic we identified a structure, and we also identified essentially a zone of about maybe up to 100 feet or 150 feet thick in the Devonian and the Fusselman that has got an enhanced porosity, and looks like a really -- what we call a porosity fairway.

And that's outlined in this orange dashed line.

And then the area -- what I did is take the area that would be encompassed by an injection of 30 years into the radial model, which turned out to be, if my memory is correct, about 156 acres, and we plotted what would be 156 acres in the direction away from the well within this porosity holiday (sic), and it's basically this green shaded area.

The purple shaded area is what would be filled up by the whole 100 percent safety factor, injecting another 15 million a day effectively into the well.

When we did that we found that even this whole green area falls within a half-mile circle still. But just because we want to make absolutely certain, we went ahead, even though we would have only really had to give notice to the operators, surface owners within the half-mile circle, we chose to do it within the one-mile circle, because of this area and also just to be overly inclusive.

So we -- we -- in our land work we Noticed every one of the surface owners, mineral owners where they weren't leased, which was basically the BLM, and the leaseholders within a one-mile circle.

Q. You used the phrase porosity holiday. Would you just explain.

A. Fairway, I think I used. If I said holiday, I was on holiday. I meant to say fairway. For us it just is a zone that has greater porosity than the surrounding rock. The Devonian really does vary a lot in terms of its porosity and permeability, and that's one of the reasons why we were so hesitant and why we did not recommend this as a zone originally, because we really didn't have the data to have a better control of that.

Like, for example, as you will see in just a moment when I show you some of the data, in many instances you have areas where the secondary porosity, especially in the Devonian, has been developed as a result of multiple instances over geologic time of that Devonian/Fusselman section being subaerially exposed, and then getting essentially karst features and large solution features and that kind of thing. And we believe we see those kind of features on the seismic data that we looked at in this area.

And that's what that porosity fairway is.

To go back to the Notice for just a moment before we go into the geologic details, we did, as I mentioned, provide Notice to everyone within a one-mile radius. We did that by Certified Mail Return Receipt Requested, and the cards and the -- or copies of all of the Notice letters and a copy of the cards, the green cards and the receipts, are all included in Exhibit 4. And in addition to that, one of the things that we did was to request from the landman -- actually I didn't have to request it because he had already done it. When he sent us the land work originally, he certified that he had, in effect, done what was required to identify all of the stakeholders in this area and to provide addresses of record so that we could make Notices to those people.

And I think in every case we received green cards back, except for three. There were approximately 30 or 31 Notices sent out to operators, primarily operators, because really in this area there is one surface owner and one mineral owner, basically, and that's it.

The surface, except for a very small portion that is owned by DCP, the surface is all BLM and the minerals are all BLM.

Q. Mr. Gutierrez I'm going to approach with an additional exhibit Marked Exhibit No. 5. Just for purposes of filling out the record, is this a -- is this an additional green card that was received after the prehearing statement was submitted by DCP?

A. This green card was received yesterday, as a matter of fact, so of the three we had missing, this was one that came back.

Q. Does the C-108 application also contain a full breakdown of all the tracts and ownership by tract, as well as by depth?

A. Yes. In Appendix B of the C-108 we provided you with all of the information directly that we got from the land office, although we summarized it here. But in there it's provided with a tract-by-tract description of who owns it and where it's located.

Q. As well as by depth, correct?

A. As well as by depth, yes.

And the ownership as indicated -- the owners and interested parties indicated are those who also received Notice letters; is that right?

A. That's correct.

Q. And did the Division also review the Notice provisions that DCP provided?

A. Yes. I believe so. The Division reviewed that. And as a matter of fact, I wanted to make sure that I had that letter from in here as a result of the conversation I had with the Division.

Q. And that was because why?

A. Well, just because I think they wanted to make certain that Notice was provided to all of the stakeholders.

Q. After reviewing that information, did the Division have any questions or concerns about the Notice, the way it was provided?

A. Not that I know of.

And of course the Notice was also published by the Commission in the paper, so that would have picked up hopefully anyone else who would not have received a Notice.

Q. Thank you, Mr. Gutierrez. If you would proceed your presentation.

A. Well, I think the Commission has seen this slide before, but it just wants to remind the Commission of what we are really looking for. We want geological seal that will permanently contain the injected fluid in the injection zone. We want it well isolated from fresh water. We want to have no effect on existing or potential production, or minimal effect, and that is part of the reason we are going deeper here.

Laterally extensive, permeable and good porosity in the reservoir. We want excess capacity for the anticipated injection volumes. We want compatible fluid chemistry. And we really see all of those things in this location.

Q. Is there any existing directional oil and gas in the target zone in this area?

A. No. As I mentioned earlier, the closest production is a well over three miles away.

Q. So not potential for production in the targeted zone.

A. We don't believe there is. None of the seismic indicated there was, either, but as the Division, and this is one of the things that was discussed with the Division and included in their letter, is that the BLM requires a very specific evaluation of the reservoir before they allow us to complete the well, and to demonstrate no producible hydrocarbons, and that will be done through sidewall cores, geophysical logs. And they also require us typically to attempt to take a swab, swab the formation and get a formation fluid.

So we will be doing that.

We identified, as I mentioned, 55 wells within the one-mile radius. Only this one well, the Lusk Deep No. 2 that penetrated the top of the Devonian is located in there. There's no completion of current production in the proposed injection zone in this area.

Within a half mile of the proposed location there are no wells penetrating the injection zone. Within a mile there is one well at .88.

We believe that after reviewing the one well that did go into the top of the Devonian, and analyzing the plugging information available, we believe that that well is adequately plugged and is out of the path, in any case.

Here you can see a picture of what I just was drawing.

The 2D well is proposed to be here. This is our porosity fairway or the portion of that porosity fairway that would be displaced by acid gas over the 30-year life of the well.

This is a half-mile radius from the well.

This is a one-mile radius.

And this is where the Lusk Deep Unit No. 2 is located.

Our radial model indicated this area would be more like a .28-mile circle around here. I believe it's likely going to be more of an oval in the kind of north/south direction here. And you will see why in a moment.

The proposed wells are located on the kind of southern slope of the northwest shelf on the basin, and the Silurian and Devonian Formations are basically carbonates that are variously dolomitized limestones and carbonates, that are contained by very low permeability limestones and shales above and below. There is good 1000-foot-plus of Woodford and Osage above the injection zone which very impermeable. And then we also have some lower permeability zones below the Fusselman and the Montoya, as well, in this area.

While we are not strictly in the required four-string area for the BLM, we have talked with them and we've elected to propose a four-string well, anyway. Because we are going to use a surface casing down about 800 feet -- let me see if I can pull up the -- oh, this is just showing you where the plant is located relative to these structural elements of the basin.

I was almost trying getting ahead of myself trying to save time here, but I'll slow down.

These logs here -- this is just a log section just to show the general stratigraphy around the plant, and these are sections of logs, obviously, that should be stacked on top of each other but they are put on here from the shallowest on the left to the deepest on the right just for display purposes.

Everywhere you see a red star that means that there's production in those zones in this area. You can se that we've got a fair amount of production above, the -- in the Pennsylvanian here, the Morrow primarily, the Atoka. And then of course we have got some production in the Wolfcamp and of course that is the target of a lot of the horizontal wells in the area.

That injection zone is shown here in blue. You can see it's well below the production in the area, and you've got the Woodford Shale above it and all of the Osage, which is a very tight limestone, above it.

Q. And blue is the proposed injection zone?

A. Yes, it is. It's right here.

Q. Can you point out the location of the Delaware with the Brushy and the Cherry Canyon?

A. The Brushy Canyon is right -- here is the top of the Brushy Canyon, here is the top of the Cherry Canyon. So our current injection zone is more like up in this area.

Q. And that's the middle stratographic column?

Just for purposes of the record, it's the middle column you're pointing to?

A. Yes, it's the middle stratographic column. At the top you can here it says Brushy Canyon, is the top of the Brushy Canyon, and the purple line above it is the top of the Cherry Canyon.

Q. Thank you.

A. This is what I was talking about relative to the design of the well. This area that's shaded in the stippled blue is what the BLM has designated as the Capitan Acquifer Protection Area. So we are right on the edge of that. And, like I said, it's not a required four-string area, but we are going to do four strings anyway.

I want to show you a little bit about what the injection zone looks like, at least what we think it looks like in this area.

You can see the dilemma. When we did the original application, only this well, which does not even fully penetrate the section, it only goes into the Devonian about 150, 200 feet, was there. We had an old induction log for that well, and we had a sonic log. Fortunately we had a sonic lot so we were able to do a synthetic on that well.

This Hackberry well, which is located approximately three miles southwest is a Concho salt water injection well in the Devonian.

Those were the only two Devonian wells in this area when we did the earlier application. Since that time, eight months ago, nine months ago, Concho completed another SWD, the Magnum Pronto well right here in Section 32. And what we've done is take a look at these wells, and then fortunately there were sonic logs on all three of the three wells, so we did synthetic seismic on those wells and we used that to calibrate. We sent that data to Devon, and they were kind enough to put that into their seismic model, and we were able to look at it all together while we were there.

So here is what the injection zone looks like. This is a section drawn on the top of the Devonian, and starts -- on the previous slide it starts here, it goes through where our well is proposed, it goes down to the Hackberry well, and then back over to the Magnum Pronto well.

And so here you can take a look at that section. This is also in the C-108.

The Devonian is here. You can see this is the well that is plugged now. It was the well -- it did drill into -- actually it did go not all the way through the Fusselman, but it did actually get into the Fusselman. So I stand corrected. It went more like 400 feet into the Devonian.

And as you move west you cross a fault that we identified on the seismic, which will be -- it's an interesting situation and very helpful to us, and I'll explain that in just a moment.

And then as you go over to the Hackberry well, you can see it's got a really -- the highlighted porosity here is more than 3 percent, and that's primary porosity developed from logs. But you can see this well has got a much better porosity picture than the Lusk well here. So it's getting better in the direction of our well.

And then in the Magnum Pronto we actually have a little change back to a little less porosity, especially in the Devonian, although we've got very good porosity and permeability in the Fusselman.

What we did is when we took the synthetic seismic for each of these three wells, we tried to look at what the character of the seismic signal was in that particular area and then compare it to the area where we are proposing the well, and that's why we were able to find the kind of amplitude changes that indicate additional porosity, and it looked very similar in those zones to the synthetic from the Magnum Pronto.

So we've used the Magnum Pronto kind of as an analog for what we anticipate in our well.

Just to give you a sense what is going on with the Magnum Pronto, they are injecting approximately -- I want to say 2 1/2 to 3 1/2 barrels a minute, something in the neighborhood of 4- to 8,000 -- 4- to 6,000 barrels a day of brine into the Magnum Pronto at a surface pressure of about 220 pounds. So it's very permeable in that area and that gave us some good feeling about where we are going to be.

This composite log section shows the injection zone and it goes all the way up into the Morrow, and you can see that basically when they drilled the Lusk No. 2 well, they drilled about this far in to the Devonian and Fusselman, and then when they found that it was wet they just plugged it all the way back to basically all the way up to the bottom of the Morrow, and they produced the Morrow for about ten years, then shut it down and replugged it.

(Note: Reporter request.)

Note: In recess from 2:12 p.m. 2:18 p.m.)

COMMISSION CATENACH: Okay. Let's get back to it.

Q. (BY MR. RANKIN) Mr. Gutierrez, will you proceed with your presentation.

A. I left off when we were talking about structure. I think we talked about this fault, but I want to show you some pictures based on what we got from the seismic.

Okay. As I mentioned, Devon was kind enough to allow us to look at this seismic and analyze it and spend a good 10 or 12 hours looking at it with them. What we found is that within the injection zone there is a fault that has a greater displacement at the top -- at the center portion of the fault, and then the top of it peters out in the Woodford Shale, right at the bottom of the Woodford Shale, and the bottom of it peters out within the injection zone; it's essentially a listric type of fault. And it is down to the west here. Our well location -- and this fault is our best representation on the seismic of where the fault is in the injection zone itself.

But we are going to drill on the downside of that fault, which is where we see the better porosity development all along here.

But interestingly enough, even though the fault continues down here, that porosity is pretty much gone in this area, and it picks back up I think further southeast, because the Magnum Pronto well is actually also along this fault further about two, another two miles to the southeast here, and it also encountered some good secondary porosity adjacent to the fault itself.

So actually this fault, why it's important to us is because it -- while the fault plane itself appears as probably not that permeable, there is a damage zone along the fault where we've had a fair amount of secondary porosity develop, based on the seismic. And the outline of the secondary porosity area is this yellow area. That's what I showed on the earlier maps.

Now, it actually looks on the seismic that it continues in this direction, but this bright red line is as far as Devon would allow us to look. The seismic to the west of there, they didn't let us look at that. So we don't really know how for it could extend, but it certainly extended to the edge of what we could look at.

This was -- so I think it probably extends at least another 100, 150 acres to the west here.

It's basically largely in the Devonian that we saw this 180 to 120 feet of this porosity unit that can be mapped by amplitude, and -- but, you know, one of the things to remember is that this is just one zone within the overall 700-foot-thick injection zone. There's a lot of other small, as you could see in those earlier logs, there's a lot of small zones that have good porosity that are interbedded with tighter zones.

And one thing I did not mention because I hadn't really gotten to the well yet, but the well that we are planning to drill is an open-hole completion in the Devonian, so it will not be cased in the Devonian, it will be open hole in the injection zone. And that is based on the experience, really, that Concho has had in the drilling of those wells, and they have had very good experience with that type of completion.

Q. Before you go on, Mr. Gutierrez, on that last slide that shows the porosity fairway and the location of that fault you identified, I think you did testify to this but I want to be sure it's clear for the record, why it is that the fault would not act as a conduit for vertical migration to shallower formations.

I just want the to make sure that was clear for the record.

A. Well, as I said, the Woodford is essentially not faulted across here. So the Woodford is immediately above the Devonian. It's a shale, and it's overlain by another 1,000 feet or so of tight limestones, and that fault doesn't penetrate through those.

Q. Because it's a shale it's tight and it has very little permeability and would inhibit any upward migration of any injecting fluid; is that right?

A. That's correct.

Q. I just wanted to make sure that was clear for the record.

A. As I mentioned, we anticipate seeing about 6,000 psi and 185 degrees in the injection zone. That is based on these data which are from DSTs of wells in the area.

So you can take a look. This is kind of what the DST data looks like. You can see that we're running from a low of about 5700 psi to about 6300 or so psi in the depth range where we're looking at the injection zone.

So this is kind of where we got that information.

Similarly, the temperature profiles, these are bottomhole temperatures from well log headers from wells in the area and that penetrate the Devonian. Actually not just in this area, it's throughout the basin they penetrate the Devonian, because there is just not that many. But what we see is we've got a pretty wide range, about 40 degrees of temperature. We are calculating we would probably be somewhere in the middle of that range based on also what we see at the Magnum Pronto.

Based on a TAG mixture of 89 percent CO_2, 11 percent H_2S, we used our AQUAlibrium software to be able to determine what a specific gravity of the injected gas would be at the surface as well as at depth, and what it would, how it would behave once it would get into the reservoir.

This is in the C-108. I know it's hard to read up here, but this table provides the detailed information that went into the radial model to determine the area of injection and also to the specific gravity used to calculate the MAOP for proposing an MAOP of 5,208 pounds.

Again, this is what the 30 years of injection, this is the half-mile radius. Like I said, if we just took our strict model that you saw earlier, it would be about -- I can't draw very carefully with my mouse here, but essentially it would be about a .28-mile circle around the well. This is the same amount of area occupied within that porosity holiday.

It may not look exactly like this, it could extend our further to the west and maybe not as much to the south. We just don't know, but we anticipate that it's preferentially going to be stored in that portion of the reservoir.

The general design of the AGI system, I'll go through this quickly because, I mean, it's very similar to what we've done on a lot of other wells, and a lot of -- all the surface facilities are basically already complete anyway with the Zia plant.

And so the surface compressors and lines are all protected with automatic safety valves to prevent overpressuring and isolate the TAG lines in the event of leaks.

We will obviously have a subsurface safety valve set at about 300 feet.

We've got fresh water that extends to about 300 feet in the area, and we are going to protect that by bringing our surface casing down to 800 feet.

Then we will have a first intermediate string which will protect the salt zone. It will go down to about 2500 feet, and also get the top of the Yates and Seven Rivers, and then down to 4500 feet with another string of intermediate casing to protect the Capitan Aquifer.

And from there on down we will go down with our production string to the top of the injection zone. There we will have about a 300-foot section of corrosion-resistant pipe that we will be set in the packer. And in this well we are also doing one more added thing for the longevity of the well. Given that we do have a well in the Brushy Canyon, and even though the bottom hole location is about a quarter mile away and we hope that we are not going to use that well as much as we have been using it when we go to the Devonian, we wanted to protect the well bore through our existing injection zone.

So we are -- in the production string we are going to sandwich in 1350 feet of CRA casing across the Brushy Canyon and Cherry Canyon so that we've got -- and we will use corrosion-resistant cement on that section, so we'll be protected from that section as well as protected in the caprock area.

The casing -- the well design is essentially similar to previous wells that we have done, which will have corrosion-resistant tubing with another section of corrosion-resistant specifically immediately above the packer. It will have the annular space filled with corrosion and biocide inhibited diesel fuel. The annular injection tubing pressure are going to be continuously monitored, and downhole pressure and temperature monitoring will also be conducted on the well.

This is a very simple schematic of what the system looks like, showing the No. 1 well, which is -- it's showing as a vertical well here but it's actually an inclined well, obviously. But it has perforations at TDD of about 5,550 to 6,050 feet, and this one, as you can see, is anticipated to have an open hole completion from 13,800 feet to about 14,750.

So over this zone here where the Brushy Canyon is, is where we're going to put the corrosion-, a section of corrosion-resistant casing and cement in our downhole, in addition to the zone where the packer is set here.

So this is the detailed design for the well. This is also included in the C-108.

As I mentioned, you can see the four strings of casing. There's surface to 800, the first intermediate 2500, second intermediate 4500, production string down to 13750, approximately, and included in this string we will have some corrosiion-resistant casing across the Brushy Canyon injection zone right there.

So all of the details are provided here, as well as the anticipated tops for each of the formations.

The casing strings will all be cemented to the surface, and that will be verified using 360-degree circumferential cement bond logs. That's a requirement of the BLM anyway.

The production string will be cemented in the injection zone for AGI No. 1 with CORROSACEM, and similarly in the caprock area for the 2D well.

And the casing and cement program we have reviewed with BLM, and they are happy with it. They had some input originally and we modified a few things, but that's how we got to where we are.

Based on the data base for New Mexico water rights, nothing has changed here. There have been no new water wells added and as a matter of fact the only four wells that are located there were really exploratory wells that were drilled by Phillips Petroleum, I think as part of a monitoring effort, and they are not currently producing any water for consumption.

Those wells are located on this map for you. You can see them relative to the proposed location of the injection well.

All of these wells have a total depth that is less than about 300 feet.

And that's the details on those that are presented in the C-108.

So to summarize, we have a number of geologic factors that ensure the integrity and safety of the proposed wells. The wells that are penetrating the injection zones are very limited, and the area of review, the caprock has got low porosity, it's an impermeable or relatively impermeable rock that is an effective barrier above the injection zone. The injection zone is vertically isolated from any adjacent productions zones. As we pointed out earlier, this fault that does exist does not extend vertically above the Woodford Shale.

The freshwater zones are way up and they are isolated by the conductor and surface casing, and the Capitan is isolated by intermediate casing.

The proposed injection pressure is going to be way below the fracture pressure of the reservoir and the caprock, and log and seismic analyses demonstrate that we have got a closed system in the area.

So in summary we are requesting that the Commission approve the C-108 at the same surface location that was approved for the Zia AGI No. 2. We want the permission to inject a maximum of 15 million cubic feet. And this is clear in the C-108 that that 15 million cubic feet would be the aggregate of what would either be injected all into the Devonian or all into the Brushy Canyon. That's what has been already approved, and we are not asking for any increase.

DCP will begin drilling as soon as we can get the permits, basically. We've got a slot in late September or mid October that Concho has made available to us, and we anticipate that, like I said, hopefully we will have the BLM permit in hand and this one, as well, and be able to spud the well.

As proposed I think this well will enhance the reliability of the plant and the AGI system, and the project is supported by BLM and Concho, and we have had no other adjacent producers complain in any way.

The proposed well will safely dispose of acid gas and effectively assures the protection of surface and groundwater resources, and prevents waste and protects correlative rights by just having a greater reliability of the plant and being able to assure that people can keep their wells on line.

That's the end of the show. Thank you.

MR. RANKIN: Thank you, Mr. Gutierrez.

I just have a few questions to follow up on and to actually just obtain your opinions, based on your review and analysis on a few things, and then I want to also address the Division's specific recommendations.

Q. Based on your review, Mr. Gutierrez, will the granting of DCP's application, as submitted, with the conditions requested by the Division, further the protection of human health and the environment?

A. Yes.

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

A. I am not, and I hope I don't become aware of that.

Q. On to the Division's recommendations.

You've had a chance to review the

Division's Exhibit No. 1 which they submitted earlier during the hearing.

A. Yes, that is correct. I have a copy of it here.

Q. Okay. And you've reviewed the additional conditions that they have requested on page 2 and 3 of that letter?

A. I have. The -- on page 3 of the letter it boils down to two additional conditions that the Division recommended. The first one is one that really is duplicative of what we already said on the C-108, and that is we are going to bring cement to the surface on every one of the strings. But we certainly don't have any problem at all with doing that condition.

The second one, which shows that the reservoir evaluation will confirm that the open hole of the AGI does not intersect the fault line, we will certainly do our best to do that. We will use every tool available, including our geophysical log, inside wall coring, and, you know, our logging while drilling, to make sure that we don't intersect that plane. We want to stay away from the fault plane. It's kind of like you want to be close to the flame but not in the fire.

And I think that the concern -- and I don't want to put words in the Division's mouth, but I think the concern about being in the fault plane is induced seismicity concern, and we don't want to have that problem, either.

So we want to try and stay away from the plane, but we want to be in the damage zone, because that is where our porosity is.

Q. Okay. I just wanted to make sure that that point came through, that in your opinion being close enough to the fault plane is actually a benefit.

If you would just touch on that point.

A. Well as I mentioned there's damage zones that occurred as a result of that faulting, and then when those zones were subaerially exposed over geologic time -- you know there was a lot of sea level fluctuation in the Devonian. I mean we're talking 3-, 4-, 500 feet sea level change. And these rocks have been subaerially exposed, and then back under water, and back up. And through that process there is some dissolution that occurs and dolomitization of that secondary porosity, and that provides us what we believe is the real reservoir, in addition to the primary porosity that exists.

Q. So being close to the fault line is beneficial for that reason?

A. Yes, it is. And the reason why it's not detrimental in terms of containment is because of the fact that the fault is limited to the injection zone.

Q. In addition to those two conditions that we just reviewed in the Division's letter, they also referenced two Orders that were permits for an acid gas injection well which you were a part of on behalf of Frontier. Is that correct?

A. Yes.

Q. Did you also review those Orders and the conditions requested and included in those Orders?

A. I did.

Q. Okay. And based on those are you willing to accept those conditions on behalf of DCP?

A. Yes, we are.

Q. In addition to those two items that would modify the C-108 as submitted, does DCP also request any additional modifications to the two Orders?

Let me rephrase that statement.

Does DCP also have any additional requests for inclusion in this Order with respect to the Division's discretion in modifying, making changes or modifications to the design elements of the proposed well?

A. Yes. I mean this is a general issue that we believe really benefits the Commission and benefits the Division, and that is that we would like to have the Commission provide in the Order the flexibility for the division director to determine, if there is a proposed change to the system or as a result of either a small technical change in the design that the BLM may bring up, or something that we may encounter during our drilling or operation that may be a better approach, we would like to have the ability to bring that to the Division and have the Division -- we will accept the Division director's determination of whether that is something that can be done administratively or needs to go to the Commission.

That is fantastic for us, and I think a good thing in general.

Q. So DCP would ask that the Commission grant the Division discretion to decide whether or not any of the proposed changes, whether by DCP or the BLM, could be approved or denied administratively, or whether they would have to go before the Commission for a hearing?

A. That would be our request.

Q. Thank you. Finally, Mr. Gutierrez, will, in your opinion, the granting of DCP's application, as proposed and modified by the Division's recommendations, result in ways to impair any correlative rights.

A. No.

Q. Were Exhibits 1 through 5 either prepared by you or under your direct supervision, or do they constitute a business record of Geolex or DCP?

A. Yes.

MR. RANKIN: Mr. Chairman, I would move the admission of Exhibits 1 through 5.

COMMISSIONER CATENACH: Exhibits 1 through 5 will be admitted.

MR. RANKIN: Thank you very much. I have no further questions of the witness and pass the witness to the Division or the Commission for further questioning.

THE WITNESS: I have one other thing that I wanted to just mention, which I realize I forgot to mention.

Unlike every other one of these permit applications that I've done, which is now getting into the 15 or 16 of them, in this case one of the conditions that we always have had imposed by the Commission was that we have a Rule 11 H2S contingency plan approved before we begin operation of the well. In this case I just want to make clear to the Commission that that plan is already in place, it is approved; and in addition, we already submitted a series of technical changes to that plan that incorporate this well so that the Division could review that. They have reviewed it and approved it on July 22nd.

So in terms of that, we already have an approval for the H2S contingency plan.

MR. RANKIN: If it please the Commission, I have a copy of that approval letter from the environmental bureau, and I'll request the Commission to take administrative notice of that approval on July 22nd.

I could pass around copies.

COMMISSIONER CATENACH: Does that have an Order number on it or is it just a letter?

MR. RANKIN: It's just a letter, yeah.

COMMISSIONER CATENACH: Okay. If we can get copies of that.

MR. RANKIN: I'll make that part of the record.

Thank you.

So with that administrative notice acknowledged, nothing further from DCP. Thank you.

COMMISSIONER CATENACH: Again, administrative notice will be taken of the letter from the Environmental Bureau to DCP dated July 22nd, 2016.

Mr. Herrmann, do you have any questions?

MR. HERRMANN: No, Mr. Chairman.

COMMISSIONER CATENACH: Okay. I'm going to let you go first.

COMMISSIONER BALCH: I'm always curious about these things, and, as Mr. Gutierrez knows, I do study a little bit of CO2 and also injection into brine aquifers.

EXAMINATION

BY COMMISSIONER BALCH:

Q. So first question is just: The Capitan Reef, I guess that's below the 10,000 TDS?

A. The Capitan Reef?

Q. Uh-huh.

A. Usually in this area it's been running about 5-, 6,000.

Q. Usable for something, I guess.

Is it the intent of your application to keep the option open to complete the 2D well in the previously specified Brushy Canyon interval?

A. Well, not the 2D well. I mean, if we drill this well and it is not successful, then we would have to come back and...

Q. So you'd complete uphole.

A. No, I think we would have to drill a new well, because I mean we really did not -- we would not want to really complete at this location in terms of a bottomhole in the --

Q. So you --

A. And we would have already had three strings of intermediate casings stuck in between. So we can't really do that.

So it had better work.

Q. Do you know what the approximate fluid composition of the Devonian is in that area?

A. It's relatively fresh, actually. I mean, relatively fresh. 60,000, maybe, TDS?

Q. Mostly salts.

A. Yes.

Q. Do you know approximately how much of that is sodium chloride?

A. I don't. Right off the top of my head, I don't.

Q. The brinier the better for storage of CO2.

A. That's correct.

Q. And you'll probably have some carbonate dissolution?

A. Our own improvement of the --

Q. Improving impermeable and imporosity of the --

A. That's correct.

Q. -- of the well bore.

The fairway model that you generated with the help from Devon, what's the -- do you have a feel for the typical permeability? Is that variable, as well?

A. I don't based on the seismic, obviously, but we do based on their, Devon's -- not Devon. Based on Concho's experience with the Magnum Pronto well.

Q. Did they take sidewall on that?

A. They didn't. They didn't take any core at all.

Q. So they don't have any core data?

A. They don't have any core data, but what they do have is injection data. I mean, they've been injecting, and they did a step rate test, and I don't think they have had to, you know, get any kind of increase in their MAOP or anything like that. It's drinking that water.

Q. Okay. The thickness of the Devonian interval, it's a little hard to pick up off the slides.

A. Sure. The thickness of the Devonian itself is probably about a total of 300 feet there, and then we get into the Wristen and the Fusselman. So the overall -- and we believe, frankly, that he even though there is some good porosity in the top of the Devonian here, that the bulk of our well is going to be made in the Fusselman, really. That's based on what we have seen in the Magnum Pronto, and the seismic attributes look very similar.

Q. So when you did your volumetric calculation, what was the porosity thickness that you used?

A. We used a thickness of, if I remember -- I'll have to go back and take a look. I want to say we used a thickness of about 300 feet of 6 percent porosity, somewhere in that range, but I'd have to go back and take a look at exactly what we did. I can do that to answer your question. (Note: Pause.)

Well, the open hole interval is going to span approximately 1,000 feet, and the available logs indicated that we had about 600 -- that we could expect about 600 feet of 7 percent porosity.

So that's what we modeled it on.

Q. Are those the numbers you used for the volumetric?

A. Yes, it is. Yes, it is.

Q. There's a potential that a lot of that fluid that's going down the Magnum Pronto well is going into a couple of very permeable stringers, or into a damage zone in the fault.

A. Yeah, it looks to us like it's going into some fairly good porosity and permeability in the Fusselman primarily, and probably into karst features in there, even though there was no direct evidence for that. You know, they did not do a detailed, like FMI type of logging, but I mean it sure looks like that from the seismic.

Q. So when DCP completes the well and then they going to go in there with sonic and other tools that will give you a better idea where your porosity is?

A. We are indeed, and we're going to get an FMI and do sidewalls. And we're going to do core analysis, as well.

Q. At that time you'll make a re-estimate of your plume diameter?

A. Yes, sir, we will.

Q. So my only other questions have to do with the fault. It looks like listric fault. It's going to be

Woodford age?

A. Yes. SubWoodford age.

Q. Terminates at the Woodford?

A. Yes, sir.

Q. And it's listric, terminating on the bottom and side of --

A. Inside the injection zone, yes, sir.

Q. Fusselman?

A. Yeah. In the Fusselman.

Q. In the Fusselman.

A. Yeah.

Q. What's below the Devonian in this area?

A. The Montoya. And then ultimately, you know, ultimately the Ellenberger in the basement.

Q. And about how much vertical distance? How much vertical thickness of sedimentary rocks from the basement?

A. You mean above the basement below our zone?

Q. Uh-huh.

A. I'm going to say about 1,000 feet.

Q. About 1,000 feet?

And you probably know where I'm going with that. They have injection -- I don't know if you're familiar with that ADM site in Decatur.

A. I'm not.

Q. They are injecting in the Mt. Simon Sandstone.

That is in direct contact with the basement. They are several hundred feet above the basement, but you can still get pressure.

A. Yes.

Q. Doesn't sound like this is an issue here.

A. I don't think so.

Q. And --

A. Yeah. And certainly Concho hasn't seen any evidence of that, either, in their salt water wells.

Q. Reactivation of existing fault there. Of course that's noting anyone would feel or be impacted by.

A. That's correct. And I mean especially in a case like this where we're dealing with a listric fault within the injection zone. So...

Q. Right.

A. And it's obvious that it hasn't had perfect motion, either, because what we saw in the seismic is that, you know, at the very top of the fault, you know, they say it peters out in the Woodford, but then you would get like maybe -- and there is not much displacement on the fault, either. You might get like 20, 30, 40 feet displacement, and then you go down another 200 feet and there is only like eight feet displacement. And then -- you know.

So it's obviously a -- not a huge fault, but it's enough to have created some damage zones that later got karsted.

COMMISSIONER BALCH: That's it for my questions.

COMMISSIONER PADILLA: None for me. Thank you.

COMMISSIONER CATENACH: Okay.

EXAMINATION

BY COMMISSIONER CATENACH:

Q. Mr. Gutierrez, you've analyzed the Devonian potential in this area. You said there was some Devonian production?

A. No, I said that the Devonian production is at least three miles away. I haven't really looked much further out than that to see where the closest Devonian production is, but I think it could be as far as 10 to 15 miles away.

Q. So you just looked at a radius of three miles?

A. Yes, sir.

Q. And there is nothing in that area.

A. Yes, sir.

Q. But you don't know what the closest is?

A. I don't right off. I mean I know that there's a Devonian field in Eastern Lea County, but that's about 15 miles away. That's the only one that I absolutely know of.

Q. Okay. What's been BLM's involvement in this whole discussion?

A. Well, the BLM requires -- for a well that is going to be drilled on BLM mineral and BLM lands, they require their own separate permitting process, an APD process, and we are going through that process, as well.

Q. Has BLM reviewed the C-108 application?

A. We have provided it to them. They have reviewed it, I think. I mean, they have reviewed our APD, which really contains the same information but kind of formatted for their consumption.

Q. These questions may be kind of random.

Can you tell me why the AGI No. 1 was deviated?

A. Sure. Because what we wanted to have -- initially the plan was we would -- we did not think that in this particular reservoir, Brushy Canyon and Cherry Canyon, that we could put away the entire volume of 15 million in a single well. So we felt like we were going to need two wells anyway. And then in order to avoid interference effects if we have to be using both of those wells at the same time, what we did was basically take the No. 1 and shoot it off in what was indicated as the best porosity permeability zone to the north, and then we were going to take the No. 2 to the south, so that we maintained about a quarter mile separation at the bottom.

So that is why it was deviated.

Q. Was that so you could put the wells on the plant location?

A. Exactly. The idea was that -- you know, for safety and operational purposes you want to minimize the amount of high pressure H2S TAG lines that you have on the surface, and so we wanted to put the surface location of the two wells relatively close together, 200 feet apart.

Q. Okay. On your plume that you've described in previous exhibits, you've got most of it going to the north and some going to the south.

A. Yes.

Q. How did you determine what direction to determine those plumes?

A. We didn't. What we did was -- here's what we did. What we basically did was take the area that would be invaded based on our radial model, and then just start filling up that area in our porosity fairway just from the top, because the well is located at the very top end of that. So we just started filling up there from there to the bottom. It's not -- we really don't have any data that would allow us to better understand how that might be filled up.

Q. So the plume, that's not an indication of what the plume is going to actually look like, it's just --

A. No, it's my best professional judgment of what it will look like. Somewhere between there and a radial kind of plume.

Q. Do you know what the -- at this point the water saturation in the Devonian is?

A. We've got a -- let's see -- we took the residual water -- let me take --

I need to get my glasses and take a look at that. (Note: Pause.)

About .7.

Q. And was that taken into account when you calculated your plume area?

A. Absolutely. Yeah.

Q. And I guess there's going to be some gas dissolved in the brine. Was that taken into account?

A. It isn't. In that sense it's a little more conservative. But in reality, I mean -- as a matter of fact, just last year I went and heard three papers at the AGI symposium about this very issue, and what you tend to see in places they've actually looked at is that the reaction, at least over kind of human time scales, is largely displacement. And then you're getting reaction at the very boundaries of that kind of ragged edge of the plume, but it's typically over a relatively small area. And that may be mineralization or those kind of effects are really much-longer-term effects.

So generally what we are doing is just displacing it with acid gas.

Q. Do you have an opinion, Mr. Gutierrez, whether or not the injection into the Concho wells will have any effect on your well?

A. We've talked about that with Concho, and we don't believe so, because I mean they are -- the closest one is two and a half miles away. I mean, ultimately if everybody starts using that zone for disposal, I mean we will see a pressure increase, for sure.

Q. So is it possible in the area that you're in, is it possible somebody could come in and drill another Devonian disposal well?

A. Well, I guess that's up to the Division whether they would approve that or not, depending on how close.

I'll give you an example of where we had to deal with this in one instance prior to when you were the director, and that was in one of those two Orders that were referenced in the Division's letter. At -- for Frontier we drilled an AGI well there, and shortly after we completed our AGI -- it's not in the Devonian but it's in the Wolfcamp. And Cimarex proposed to put a salt water injection well about a mile and a half, or a mile -- yeah, a mile and a quarter to the southwest of us.

And at that time when Cimarex made their application, the Division contacted us and said: Are you concerned about this? The BLM did, as well, actually.

We talked to Cimarex about it. I talked to their geologists. We got together, and we felt pretty good that we wouldn't have a problem.

And then when we put in the second well for Frontier, we actually found that we really wanted to get closer to their well, because the permeability was significantly improving in that direction, and so we met with them and with the Division, and we agreed that as long as we stayed a half a mile away we would be okay.

And that's what we did, and we haven't seen any effect from their well into ours. At least not yet.

Q. We have had some recent issues with a Targa well. One of them concerned the subsurface check valve, basically in the tubing that you plan installing in this well at about 200 feet, I think was the...

Have you had any experience with that or any problems associated with running those types of valves?

A. Not at all. But what there is a problem with is, is that the subsurface safety valve has a reduced ID, and you cannot get a check valve or plug past that once you have put that valve in. If you set up the well right you can put the right size profile nipple at the bottom so you can use a smaller plug, and then you can get it right through the line. But if you don't think about that before you complete the well, then you might not be able to get, say, a piece of -- in the case of the Targa wells specifically, they couldn't get the plug to plug off the Packer through the subsurface safety valve.

But if you have the right set-up in your -- the right profile nipples in your packer arrangement then you can do that. You can certainly get them past that valve.

Q. So in your well design you've anticipated that problem and plan to take care of it?

A. Yes.

MR. RANKIN: Mr. Gutierrez, just to clarify if I might, you used the term ID. Does that mean the interior diameter?

THE WITNESS: Yeah, inside diameter.

MR. RANKIN: Inside diameter. Right.

Q. (BY COMMISSIONER CATENACH) In that particular well, and I'm just throwing out what we've learned from these in recent times, that well was drilled in 2011 and we already have a casing in that well?

A. Yes.

Q. Have you seen any of that in the wells that you've been associated with?

A. No, not a casing leak, but I have seen the effects of -- actually in a DCP well, at the Lynum No. 1 well, we had a tubing leak that did compromise some casing. It never caused a casing leak, we haven't had a casing leak at all, but it did have a zone of casing where the integrity was somewhat compromised, and part of our plan for that well going back is to stack another packer to avoid that area.

But the bottom line is this: You have got to keep TAG out of that annular space, and you have to have an nonreactive fluid in that annular space that would minimize the impact if you do have a leak.

But in my opinion the critical thing is to monitor injection pressure, injection temperature, and annular pressure, and to stay on top of that, and if you see a trend that looks bad, you get on it right now.

And I think that's a real issue. I do believe that -- while I believe that MITs are very useful and I do believe that we need to have MITs on an annual basis for AGI wells, you can't rely on just an MIT, because you really have to look at how the well is behaving, because the problem is that, as we found out from the Lynum No. 1, when you do have a problem -- in other words, what happened in that casing is maybe a little bit different in that you had some free water that developed inside the tubing, and then it corrodes very quickly. It can corrode very quickly.

So I think it's really crucial to monitor those pressures in the same way that we propose to do here and that and we do on all of our wells.

Q. And you're proposing in the annular spaces to put what type of fluid?

A. Corrosion inhibited diesel with biocide.

Q. Has that been successful in the wells that you have run it in?

A. Yes, sir, it has. And I think it is a large reason why we didn't wind up with a casing leak at Lynum No. 1.

If you get TAG, the slightest amount of that TAG, whether it's just CO2 or H2S, outside the tubing and in an aqueous environment, it's pretty aggressive.

Q. I think I've been involved with -- I think it was Frontier maybe with its use of the bottomhole pressure temperature sensors.

Is that my recollection?

A. That is exactly right. I mean, that's something that frankly the whole industry is struggling with right now, because the systems that are available, commercially available for monitoring bottomhole temperature and pressure, in my experience they are not the most reliable things in the world, right?

So my client at Frontier, being aware of that issue, when they were required in their second well to put bottomhole temperature and pressure monitoring equipment in the well, they were very concerned about: Well, what happens if this equipment fails?

I mean, in reality the purpose for that is to really help you gather data on how the reservoir behaves so that you can come back ten years down the road and say to the Commission: Okay. Here is what we said it would do, here's what it did, and then make adjustments, as necessary, in the operation or the Order going forward.

Well, the concern is if you have that equipment go down, the only way to fix it if it's a downhole problem, is you got to work over the well. And you know that's a very expensive process for just...

So what we wanted to do is to have an ability to satisfy the need for gathering those data but not necessarily have to work over the well immediately if those things fail. And that's what we came up with that we negotiated with the Division, and that you provided for us as an amendment to one of those Orders that laid out a program: Okay, if that fails, then -- you know, of course you do everything you can to try and fix it without working over the well, but if you can't, then the substitute is that, you know, you at least put in bottomhole pressure and measurement equipment on a, let's say two-week basis for -- within a two-year period, so you can gather some of that bottomhole data. And you do that, hopefully, and then work over the well at its nearest -- you know, whenever you are going to work it over for another reason.

Now, very frankly I think this is an issue that really does need to be addressed. And it may take some time to figure out what is the best way to do it, because it's just a function of the equipment that's out there is just not as reliable as you would like it to be.

FURTHER EXAMINATION

BY COMMISSIONER BALCH:

Q. Are you aware of Summers Ames (phonetic) memory gauge tools?

A. I don't know about the memory gauge.

Q. Basically it's a wire line or tool that they can drop down to the bottom of a well, self-contained package with a battery and temperature and pressure sensors.

A. Right.

Q. Records for three to six months, and then you pool it out and take the data.

A. Right.

Q. So that would be a good fall-back position for --

A. That is exactly what we came up with. Not using that particular tool, but that methodology is what was arrived at to deal with a potential problem. This is not a problem that has arisen yet at Frontier, but a potential problem that might arise, and it would be essentially that.

But, you know, the problem is when you put a slick line in an operating AGI well you basically have to shut it down to put the -- I mean, you could put a -- you know, you put a lubricator on it and that, but you still basically have to shut down the well, because you can't really -- they're not going want to have their slick line in there while you're injecting TAG. They do have acid gas resistant ones, but they don't like just keeping that in.

So typically we would put a bomb down the well and leave it down.

And the other advantage where you have a two-well system -- not in this case because they are in two different zones. But if you have a two-well system in the same zone, you can actually monitor the one well while you are injecting into the other one, and vice versa, and get that downhole data.

But that whole issue of how to get realtime downhole data that is really reliable is something we are really struggling with.

And there's a variety of different manufactures, SlumberJ, Baker Hughes, Halliburton, they all have individual tools but they all suffer from some fundamental weaknesses. One of them is lightning. Lightning can affect these things pretty dramatically, and then it kind of tends to fry the wire and it fries it at some point between the surface and 10,000 feet. You know?

So it's a challenge is what it is, and I think that what Commissioner Catenach mentioned is a good workaround for that. That balances the need to get the data and the expense of working over the well.

COMMISSIONER CATENACH: Any further questions?

Okay. Anything further?

MR. RANKIN: No.

FURTHER EXAMINATION

BY MR. RANKIN:

Q. I think, Mr. Gutierrez, I think you addressed the Commission's questions on the downhole monitoring, but I think is that something that you discussed with the Division already to some extent with this well?

A. No, Not specifically. I mean, we discussed it in the context of what's been done at other wells.

Q. Okay. Is that something, were the issue to arise, something that DCP and the Division would discuss addressing at that time?

A. Yes.

Q. And you feel that is something that could be handled administratively between DCP and the Division?

A. Yes. As it was with Frontier.

Q. And if there were an issue that was larger, could that be something the Division could recommend to be brought before the Commission?

A. That would be the director's prerogative.

MR. RANKIN: Thank you. Nothing further.

COMMISSIONER CATENACH: Okay. Anything further? Okay.

So do I have a motion to go into executive session?

COMMISSIONER BALCH: I would make a motion to go into executive session.

COMMISSIONER PADILLA: Second.

COMMISSIONER CATENACH: All in favor.

COMMISSIONER PADILLA: Aye.

COMMISSIONER BALCH: Aye.

COMMISSIONER CATENACH: Aye.

(Note: In recess.)

(Time noted 3:30 p.m.)

COMMISSIONER CATENACH: All right. Do I have a motion to go back into open session?

COMMISSIONER BALCH: So moved.

COMMISSIONER PADILLA: Second.

COMMISSIONER CATENACH: All in favor?

COMMISSIONER BALCH: Aye.

COMMISSIONER PADILLA: Aye.

COMMISSIONER CATENACH: Aye.

Again pursuant to the Open Meetings Act we have discussed this case and this case alone during the executive session. We have reached a decision in this case.

The application in this case will be approved. There are no special conditions that we are putting on this well other than what's normally been routine in some of the other Orders.

We would like a finding in the Order authorizing the Commission director to approve administrative changes, minor changes to the plan. That can be approved without coming back to the Commission. So if you could put something in that Draft Order to that effect.

When can you have us a Draft Order?

MR. RANKIN: If not tomorrow, Monday.

COMMISSIONER CATENACH: Okay. That should give us plenty of time to review the draft before September 6th.

MR. RANKIN: My hope is to give you as much time as possible to review it, make any changes or would like to make in advance of that September 6th meeting.

COMMISSIONER CATENACH: Now, I want to make sure if can we put that on the September 6th docket.

MS. DAVIDSON: I believe when I get the final one out.

COMMISSIONER CATENACH: Okay. That would be great. We can review the Order and hopefully get this taken care of at the 6th hearing.

Thank you very much.

Okay. This hearing is adjourned.

(Time noted: 3:35 p.m.)

STATE OF NEW MEXICO)
) SS
COUNTY OF TAOS)

REPORTER'S CERTIFICATE

I, MARY THERESE MACFARLANE, New Mexico Reporter CCR No. 122, DO HEREBY CERTIFY that on Thursday, August 25, 2016, the proceedings in the above-captioned matter were taken before me; that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability and control.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with (unless excepted by the rules) any of the parties or attorneys in this case, and that I have no interest whatsoever in the final disposition of this case in any court.

Mary Macfarlane

MARY THERESE MACFARLANE, CCR
NM Certified Court Reporter No. 122
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