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

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

ORIGINAL

APPLICATION OF DCP MIDSTREAM, LP, TO RE-OPEN CASE NO. 13589 TO AMEND ORDER NO. R-12546 FOR THE LIMITED PURPOSE OF AUTHORIZING A SECOND ACID GAS INJECTION WELL, LEA COUNTY, NEW MEXICO

Case No: 13589

REPORTER'S TRANSCRIPT OF PROCEEDINGS
COMMISSIONER HEARING

BEFORE: JAMI BAILEY, Chairman
DR. ROBERT BALCH, Commissioner
TERRY WARNELL, Commissioner

December 20, 2012
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission, JAMI BAILEY, Chairman, on Thursday, December 20, 2012, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

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ALSO PRESENT:

Randy Smith
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Theresa Duran-Saenz

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CHAIRMAN BAILEY: Good morning. This is a special meeting of the Oil Conservation Commission on Thursday, December the 20th, in Porter Hall, in Santa Fe, New Mexico.

To my right is Terry Warnell, who is the designee of the Commissioner of Public Lands. To my left is Dr. Robert Balch, who is the designee of the Secretary of Energy, Minerals & Natural Resources. I am Jami Bailey, Director of the Oil Conservation Division. And today we have as Commission counsel Bill Brancard. There is a quorum of the Commissioners here today.

We have a series of minutes of previous meetings that will need to be addressed. On November 15th we held a meeting, and the Commissioners were Greg Bloom, who is the designee of the Commissioner of Public Lands; Robert Balch and I were part of that Commission hearing.

Have you had a chance, Dr. Balch, to read the minutes of November 15th, 2012?

COMMISSIONER BALCH: I have.

CHAIRMAN BAILEY: Do you support and make a motion to adopt these minutes?

COMMISSIONER BALCH: I will make a motion to adopt the minutes.

CHAIRMAN BAILEY: All those in favor?

Then I will sign on behalf of the Oil Conservation Commission.

Commissioner Warnell, you were present for the Oil Conservation Commission meeting held on December 6th, 2012. Have you had a chance to read the minutes of that meeting?

COMMISSIONER WARNELL: I have.

CHAIRMAN BAILEY: Do I hear a motion to adopt the minutes?

COMMISSIONER WARNELL: I'll make that motion.

CHAIRMAN BAILEY: All those in favor?

Then I will sign on behalf of the Commission.

Dr. Balch, the minutes of the meeting of September 24th, 2012, indicate that Greg Bloom was representing the Commissioner of Public Lands. He is not here today, but you and I were part of that meeting. Have you had a chance to read the minutes of the September 24th, 2012, meeting?

COMMISSIONER BALCH: I have read the minutes.

CHAIRMAN BAILEY: Do I hear a motion to adopt the -- oh, also the meetings that were held on September 24th through the 27th, and October 1st, 4th and 5th, 2012. So it reflects quite a few days with the minutes.

COMMISSIONER BALCH: I will make a motion to adopt the minutes.

CHAIRMAN BAILEY: All those in favor?

And I will sign on behalf of the Commission.

Also, we have an order of the Commission drafted to reflect the request of the Independent Petroleum Association of New Mexico requesting a dismissal of its petition in Case Number 14785 to the extent that it seeks an amendment to NMAC 19.15.39.8(B). This was at the request of the applicant.

Have you had a chance to read this draft order?

COMMISSIONER BALCH: I have read the draft.

CHAIRMAN BAILEY: Do I hear a motion to sign this order on behalf of the Commission?

COMMISSIONER BALCH: I will make that motion.

CHAIRMAN BAILEY: All those in favor?

I will sign, you will sign, and we will send it to Commissioner Bloom for his signature. And I'll transmit these to the substitute Commission secretary today.

I will now call Case Number 13589, which is the application of DCP Midstream LP to reopen Case Number 13589 to amend Order Number R-12546 for the limited purpose of authorizing a second acid gas injection well in Lea County, New Mexico.

I ask for appearances.

MR. RANKIN: Good morning, Madam Chair, Commissioners. Adam Rankin, with Holland & Hart, on behalf of applicant, DCP Midstream, LP. I'll have three witnesses today and a brief opening statement. Thank you.

MS. GERHOLT: Madam Chair, Commissioners, Gabrielle Gerholt on behalf of the Oil Conservation Division. The Division will present two witnesses today, Will Jones, of the Engineering Bureau; and Elidio Gonzales, the District 1 supervisor. I also will have a short opening this morning.

MR. ALVIDREZ: Madam Commissioner and Commissioners, Rick Alvidrez on behalf of the Smith Ranch and Randy and Naomi Smith. And we will have five witnesses, two live and three by telephone.

CHAIRMAN BAILEY: The first order of business should be the request by DCP, a motion to file a late exhibit. Would you care to comment about this motion to file a late exhibit?

MR. RANKIN: Madam Chair, we filed this

late exhibit this week as a result of the Division's request to collect an additional water sample. DCP had submitted some earlier water samples that were a few years old. And Mr. Jones, of the Division, had asked Mr. Gutierrez, of Geolex, a consultant working on this matter, to provide an updated water sample, which they did.

The request was made last Wednesday. And the water sample was collected and the results were returned on Tuesday, and we hastened to file the water sample with the Division and to file this motion.

I talked with Mr. Alvidrez, the counsel for the Smiths, and my understanding is he does not oppose the submission of this water sample as an exhibit today.

MR. ALVIDREZ: That's correct. We have no objection.

CHAIRMAN BAILEY: Ms. Gerholt?

MS. GERHOLT: The Division definitely doesn't have an objection, since we requested the information.

CHAIRMAN BAILEY: Do I hear any discussion from the Commissioners for accepting the late exhibit?

COMMISSIONER BALCH: I'm always in favor of more data.

COMMISSIONER WARNELL: That's fine.

CHAIRMAN BAILEY: Then the Commission will accept the late exhibit.

MR. RANKIN: Thank you, Madam Chair.

When it comes time, I have a hard copy which I can distribute when we get to that exhibit, if you don't already have it.

CHAIRMAN BAILEY: Do you have an opening statement?

MR. RANKIN: I do. Thank you.

Madam Chair, Commissioners, DCP's application to reopen this case is a for a very limited purpose. It's to approve a second acid gas injection well. DCP already has one AGI well approved and operating at this facility. The proposed second well will be injecting into the same formation that the Commission has already approved for acid gas injection.

After three years of injecting through the AGI Number 1 into the Lower Bone Springs, the same formation that we're seeking to inject into today, you will hear testimony that confirms that the Lower Bone Springs formation is an ideal reservoir for the injection of acid gas, better even than DCP thought when it originally brought this case for the original well.

DCP is seeking approval for its second well to improve reliability of the acid gas plant. You will hear testimony that the second well is expected to have the added benefit of reducing the potential for flaring and the environmental impacts.

Every time the AGI Number 1 has to be shut down, it creates a risk of damage to upstream wells and the potential for environment impacts, such as flaring and even possibly venting from wells upstream and damage to those wells.

As you'll hear today, the AGI Number 1 did experience some operational issues in late 2011, which resulted in a minor limited leak of acid gas that was fully contained within the well itself until it was released during a workover in April of 2012. It was a short duration release. It was limited, and it didn't rise to a Category 2 event under the contingency plan.

Nonetheless, DCP took the cautious approach and notified the Division and implemented its contigency plan -- its workover contigency plan at the time. That event, which caused the AGI Number 1 to be shut down for approximately three weeks, necessitated the shutdown of thousands of wells behind it, and it prompted the Division itself to discuss and breach the topic of implementing or drilling a second injection well in order to increase the plant's operational reliability and to avoid further shutdowns.

DCP liked the idea. The second well made sense for a number of reasons that you'll hear today. The Division itself is here to support this application.

It is, however, being opposed by the Smiths. At the last hearing before the Commission in July 2011, they expressed concerns over DCP's operation of the AGI facility and raised the allegation that the well had contaminated their water.

Now they think they have groundwater samples to prove their allegations, and they have stipulated penalties that DCP has paid the NMED that they think indicate DCP's shoddy operations of the facility.

But as you'll hear shortly, these allegations have no basis. The Smiths will present no information that the Division doesn't already know or that should have any bearing on the approval of this application. In fact, the second well will only help to address their concerns about flaring at the plant because it will improve the plant's overall operations and reliability.

Finally, the claim that DCP's injection has contaminated the well has absolutely no basis in fact, either. As you'll hear and the Smiths' own evidence will show, the well has fluctuating levels of sulfates and sulfides which demonstrates almost to a diagnostic certainty that their sulfur issues are related to biological activity and not any impacts or effects from the AGI well or injection. Thank you.

MS. GERHOLT: Good morning, Madam Chair, Commissioners. The Division is not in opposition of DCP's application to seek to allow the authority to inject into a second well.

We do ask that if the Commission approves that, that yearly MITs be required; that daily monitoring of pressure data, diesel replacement, atmospheric H2S and safety measures be required; and that monthly reporting on the Form C-103, so that it will go into the well log, is also included, if the Commission so chooses.

Finally, we ask that DCP be required to work with the Division in providing immediate notification parameters for the well, so if there is an issue with the well, these parameters are met and immediate notification to the Division and proper steps can be taken.

You will hear from both Mr. Jones and Mr. Gonzales regarding their review of the C-108 application, and they are here to provide information to the Commission and answer questions. Thank you.

CHAIRMAN BAILEY: Mr. Alvidrez, do you have an opening?

MR. ALVIDREZ: Yes. Very briefly, Madam Chair, Commissioners, we're here today on behalf of

Mr. and Mrs. Smith, who are neighbors to this acid gas plant and even closer neighbors to the operating well that currently exists and the new one that's being proposed to be installed.

And the Smiths testified previously in this docket with respect to their concerns because of the very toxic nature of the gas that's being dealt with at this plant and the fact that they are experiencing levels of H2S in their wells from samples that they've taken and are very concerned from a health standpoint about the impacts to them and their family on their ranch, on their property.

We think that the record of operation at this facility has, in fact, been quite shoddy. In fact, it's clear in the first part of the hearing that the reason this well was installed in the first place was because the Linam plant could not comply with applicable environmental regulations, and this acid gas injection well was supposed to be one of the means that was going to help with compliance.

Of course, since that time and since the plant has been operating, we've seen continued noncompliance from an air quality standpoint. And certainly there's been concerns, as evidenced by the Division's own internal documentation, that the problems with the existing well have existed for some period of time. In fact, they were likely in existence when we had our last hearing, yet they weren't really disclosed to anyone.

But there were probable tubing packer leaks back in the winter of 2010. And we've seen the situation where, in fact, those problems have led to a release of toxic gas into the atmosphere. We had alarms going off.

I can tell you that the Smiths will testify that when these happen, they don't get any warning. When they see emergency things happening, they call the numbers that were provided, and no one answers the phone. And they live -- they've got a home next to this plant and next to this well, and these are certainly very concerning.

And we think it's incumbent upon the Division and this Commission to ensure that there are adequate safety procedures in place; that the integrity of the existing well, as well as the new well, be established, as well as the integrity of other wells in the area that could be the cause or the source for what we're seeing on the Smiths' property.

And that's why we're here today. And we hope to get into these topics in a little more detail and hope that the Commission will delve into these, as well, in their questioning. Thank you.

CHAIRMAN BAILEY: Mr. Rankin, are you ready to begin your case?

MR. RANKIN: I am, Madam Chair. Thank you.

I'd like to call my first witness, Mr. Alberto Gutierrez.

CHAIRMAN BAILEY: Would you please stand to be sworn?

ALBERTO GUTIERREZ

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Gutierrez, can you please state your full name for the record?

A. Yes. Alberto A. Gutierrez.

Q. And where do you reside?

A. I live in Albuquerque.

Q. By whom are you employed?

A. I'm employed by Geolex, Incorporated.

Q. What's your position with Geolex?

A. I'm the president of the company.

Q. What exactly does Geolex do?

A. Geolex is a consulting firm. We specialize in environmental consulting, particularly geologic and engineering issues. We have a variety of areas that we specialize in, but primarily we specialize in the evaluation and location and completion of acid gas injection and disposal wells.

And we also do a lot of work related to groundwater contamination, determination of groundwater contamination sources, groundwater remediation and this type of work.

Q. Mr. Gutierrez, have you previously testified before the Commission?

A. Yes, I have.

Q. Just because this is a new constitution of the Commission, would you please summarize your educational background and experience? And I believe Exhibit 1 is a summary of your CV, education and work experience; is that correct?

A. That's correct. Basically, I am a geologist. I attended McGill University in Montreal for a couple of years. And I got my undergraduate degree from the University of Maryland in Gemorphology in 1977.

Subsequent to that, I came to New Mexico and went to graduate school at UNM. I got a degree in geology and hydrogeology from UNM in 1980, a Master's degree.

I am a Registered Professional Geologist in approximately 20 states and have done work over the last 35 years all over the U.S. and abroad in this field.

Q. How many AGI wells approximately have you worked on?

A. Probably about 15 wells overall. All of the wells in New Mexico, with the exception of the Marathon well.

Q. At the time you previously testified before the Commission, were your qualifications as an expert in groundwater contamination and hydrology and AGI design and operation accepted and made a matter of record?

A. Yes, they were.

Q. This is a copy of your resume, is that correct, Exhibit Number 1?

A. Yes, that's correct.

Q. Now, have you previously worked on this Linam acid gas injection facility, the existing AGI Number 1?

A. Yes. Really, I've been involved in it from the inception of the concept of having an AGI at the Linam facility. My company and I personally did the original feasibility study for the current AGI well, and I testified in front of this Commission for the original permitting of that well and then for a number of subsequent changes that we made to that order.

Q. Originally, you evaluated the Lower Bone

Springs and the proposed injection zone for its feasibility as a reservoir for injected acid gas?

A. Yes. We evaluated all the zones in that area, and we chose the Lower Bone Springs as the best zone for quite a number of reasons.

Q. So you prepared the C-108 that was filed with the Division for the approval of the second acid gas well; is that correct?

A. That's correct. I did the original one back in 2005 and testified in 2006. And on October 29th of this year, I turned in the application for the AGI Number 2.

Q. So you're very familiar with this application?

A. Yes, sir.

Q. Did you prepare any more exhibits to discuss today?

A. Yes. I also prepared a PowerPoint to summarize the key points of the application. And I understand we're going to look at some of those slides as we go through the testimony.

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

CHAIRMAN BAILEY: Any objection?

MR. ALVIDREZ: No objection.

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: He's so admitted.

Q. (By Mr. Rankin) Mr. Gutierrez, can you please just provide the Commission -- you already touched on this a little bit -- but just a little more background on what you did with the original application, since it's been a number of years now, just to familiarize the Commission with the work that went into the original application to analyze the injection formation and the work that supported the application that you did?

A. Sure. Just by way of history, this was the third AGI that was ever drilled in New Mexico. The first one was done by Marathon quite a few years ago, and then there was another one done by DCP at the Artesia plant, and this was actually the third AGI that was drilled in New Mexico.

In 2005 we were retained to do a feasibility study to evaluate potential reservoirs. Ideally, the original intent was to find a location for a well that would be actually on the Linam plant itself.

However, when we did the geologic investigation there, which involved evaluating available well information from surrounding wells, we also purchased a number of seismic lines so that we had seismic control in the area.

We determined that unfortunately, at the plant itself was not a good location because these reservoirs are just not present and not adequate in the area of the plant.

The plant is located on the northwest shelf, which is a higher area in the subsurface between the Delaware Basin to the west and the Midland Basin to the east. And these formations that drape off of that -- the Lower Bone Springs, in particular, which drapes off that Central Basin Platform, as it's called, just was not available at the plant site.

So we found, through our work and our feasibility study, that the best location was approximately about mile and a half, a mile and a quarter, north of the plant, approximately in the current location where the AGI Number 1 is.

Q. That's the same approximate location that we're looking at today for the AGI Number 2 well?

A. That's correct. As a matter of fact, it's within the same unit letter.

Q. Just to summarize what it is DCP is looking to do and request of the Commission today, can you give us just a brief summary of what it is that the application seeks?

A. Sure. It's pretty simple. What we're looking for is just another avenue to put acid gas into the Lower Bone Springs. The AGI facility, as a whole, has redundancy in compression and other key elements of engineering, but it has no redundancy in the wells.

So in other words, if we have a problem with a well -- originally, when the AGI was started up initially, we still had a functioning SRU, or sulfur reduction plant, at the Linam facility. So if there was a problem with the well, they could restart -- even though it was difficult and troublesome, they could restart the SRU.

The SRU is no longer a feasible option. It's been completely closed down as part of the agreement with NMED to basically improve air quality.

So now the functioning of the plant, as the Commissioners well know, these plants are throughput plants. They don't store any gas. They just take the gas, process it live and put the sales gas into the pipeline; and then put the waste gas, which is CO2 and H2S in this case, the acid gas, into what would have been a sulfur reduction unit and now is an AGI well.

If you have a problem with the AGI well, similar to the problem that we had with this well that required that the well be worked over, essentially the plant has to be shut down during that time period because they can't continue to process gas and flare the waste gas and still meet air quality regulations.

So the workover, really, of this well started the Division discussions that I had with Mr. Gonzales while the workover was going on about the future and what would be a better approach going down the road.

And we agreed -- and I talked to DCP, and we all agreed that a second well would be a prudent step that would allow redundancy to allow injection to continue and allow the plant to continue to operate in the event that there's a problem with the well.

Q. You've given a little bit of the rationale and the background for the application. Let's get into the application now. But first, let's deal with the notice issue.

First, what is the status of the land on which the proposed AGI Number 2 will be located?

A. The AGI Number 2 is located on land owned by the State of New Mexico. It's state trust land. We have a business lease -- or DCP has a business lease for the quarter section where the well is located.

Q. And who was notice provided to?

A. We provided notice as per the current policy of this Commission, which is to provide notice to -- it's a two-fold notice. One is a notice to all landowners within one mile of the proposed location of the well. We did that. That's surface landowners.

Then there is a cascading notice provision to provide notice within one mile to any operator: First, any lessee; second, and in the event that there are unleased portions of land, then to the mineral owners associated with that particular parcel.

Q. Mr. Gutierrez, looking at Exhibit Number 2, this is the notice exhibit that was put together. The first page of that exhibit is an affidavit prepared by counsel for DCP indicating that notice was provided as required by the rules; is that correct?

A. Yes.

Q. And following that page is a sample letter that was sent by you to all the interest owners whom you've identified as being with within one mile of the proposed AGI Number 2; is that correct?

A. That's correct.

Q. On the following pages are all the green -- rather, the return receipts for those letters that were sent out?

A. Yes, sir.

Q. And if you dig through those, the subsequent pages are all the green cards that were received for those individuals who actually signed for the notice; is that correct?

A. That's correct.

Q. And following that batch of green cards, you'll see a table that just indicates the status of some outstanding notice letters; is that correct?

A. That's correct.

Q. And following that page is a batch of notice returns that were received either for bad addresses or some are no longer there; is that correct?

A. Yes, sir, or deceased.

Q. And following that exhibit, Mr. Gutierrez, is an Affidavit of Publication for the publication of an ad that ran in the Hobbs newspaper; is that correct?

A. Yes, sir, that's correct.

Q. And this is an affidavit indicating that we published what?

A. Well, as I mentioned -- and if I may, I'll give a little bit of background, because it's quite an interesting situation that I had not encountered before.

When we did the original application, we only -- this was before the Commission had a policy of notifying everyone within a mile. We did a half-mile notice in the original application back in 2005, because that was the procedure at that time, so we didn't run into this issue.

But as we expanded that notice to a mile, we encountered a number of parcels of property that contained unleased minerals. And furthermore, we encountered a number of properties that contained leased minerals being held by production, but that had a rather unusual lease provision called a pugh clause. It was -- I learned about this from our land people.

We hired MBF to do the land work associated with this. It turns out that some of these leases have what is called a pugh clause. And this pugh clause basically says that in a normal oil and gas lease, if you establish production, you hold that lease by production for an indefinite period of time while the production is going on.

These pugh clauses, which were present in a number of the private leases here, require that after the end of the first term of the oil and gas lease expires, that even if there is production on that property, any zones or potentially productive zones that are below the deepest production on that lease, those zones revert back to the mineral owner as unleased.

So what has happened is that on some properties to the east, we have that situation. And there were a number of these properties where the interests had reverted back to these old mineral owners for everything, say, below a certain depth. And it was quite a challenge.

We had a person from MBF. We hired MBF in Roswell, which is a professional company that does this land work. And they had someone at the Lovington courthouse five days a week, eight hours a day, for five weeks, to be able to track down all of these mineral owners. And many of them were -- had addresses that had not been revised since the mid 1950s.

And so we went through quite a process trying to identify who they were. Many of them were very fractional interests. As a matter of fact, I had to laugh. In some of these cases, there was someone who had a 2 percent interest. And ultimately, by the time all their heirs had it, they had divided it 64 times, this 2 percent interest. So we ended up having to notify quite a few people and tried to track them down.

There were a number that we got either returned because the individuals were no longer at those addresses, as you can imagine, or may have been deceased or whatever. And as a result of that, we conferred, you and I conferred, and thought that it would be best to go ahead and publish the names of all of those people that we weren't able to track down and put it in a public notice. That's what this Affidavit of Publication represents.

However, after that time -- and I don't know if it's really as a result of this notice or not, but maybe some of those things were delayed -- a number of people on this list in the publication, we actually did get their returns and they did receive their notices and their applications. But at the time when we published this, there were the people who we either had not received the green cards back from or we had the applications returned because of bad addresses.

Q. So all notice that was mailed was sent based on the title of the lands and the interests as recorded at the time the application was filed; is that correct?

A. Yes, that's correct.

Q. And any interests that were unlocatable were included by name in this publication, giving notice of this hearing and the application?

A. That's correct. And as I mentioned, a number that were -- in an abundance of caution, there were a number that we actually got back that we had published in here, as well.

Q. In your opinion, did you undertake a good-faith effort to provide notice as required by the rules?

A. Yes.
Q. Thank you.
Now, moving on to the application, DCP filed a C-108 with this application, is that correct, and provided that to the Division, as well as to the District Office in Hobbs?
A. Yes, on October 29th, 2012.
Q. Because this application is for an acid gas injection well, DCP also filed an application for a hearing before the Commission; is that correct?
A. Yes, that's correct.
Q. Now, the C-108, which is marked as Exhibit 4 in the binder, contains all the information required by the Division on the C-108; is that right?
A. Yes, sir.
Q. Turning to Exhibit Number 4, let's look at Tab Number 1. This is an overview map of the area. Could you please review for the Commissioners to give them -- to get them oriented to where we are here in the world?
A. Yes. The city of Hobbs is right here. The Linam gas plant is located here, approximately four miles west of Hobbs, along Highway 180-62. And the acid gas injection facility is located here, approximately one and a half miles north of the plant.
Just here, to the west of the AGI facility, is

the Maddox Station, Maddox Xcel Energy Plant. So that's basically a location map to show the general area.

Q. One thing I wanted to have you point out is that where you identified the proposed Linam AGI Number 2 --

A. Yes, sir.

Q. -- that was in the original C-108 application; is that correct?

A. That's correct. We had originally talked about and looked at a location -- when we looked at the AGI facility itself -- and I think later on, when you see an aerial image of the AGI facility, you'll be able to see this -- but the only area within the current fenced location that has an open enough area where you could set up a rig and do drilling of an additional well without impacting the current operations was approximately -- within the existing fence line was to the northeast, about 250 feet to the northeast of the original well. That's where we proposed it originally.

Then when we went out in November -- and we talked about the different advantages or disadvantages of each of those locations. When we were out in November to do the MIT test that we'll talk about that was done in November of this year, we were out there with the Division and with Mr. Boatenhamer, who will testify later, who is the plant manager at Linam. And we thought, is there a better location for this well within the current quarter section that DCP has leased from the State Land Office?

And from a geologic standpoint, Mr. Boatenhamer said, "If we were to move this well to the south of the current well, rather than the northeast, it would be a better situation for us from the operations perspective." Because if we were working on one well and injecting into the other well, we wouldn't necessarily be directly downwind of the existing well, which is where we would be if we had selected the location we originally proposed in the 108.

And Mr. Gonzales was present out there from the Division at the same time, and he agreed. And I said, "I'd like to look at the geology and make sure that we don't have a problem." I didn't think we would, because we were still talking very close to the existing well.

But then it was decided it would be more appropriate to move the well about 400 feet south of the existing well, rather than 250 feet northeast. Now, that's still within the same unit letter. I believe it's K or L. Unit K. It's still within the same unit, and it's still within the three -- I mean 160 acres that DCP has leased there, but it will require extending the fence somewhat to the south.

Q. Can you please give us what the new proposed footages are for the location of the well?

A. I have to look at those. I think it's 1,600 feet from the south line and 1,750 feet from the west line.

Q. Thank you, Mr. Gutierrez. And that's in Section 30, Township 18 South, Range 37 East?

A. That's correct. It's in the same section. It's literally only about 450, 500 feet away.

Q. You mentioned that you wanted to ensure that the change in the proposed location wouldn't affect at all the well's ability to inject into the target formation. Did you decide that it was an okay location for that?

A. Yes. After November 14th, when we had this discussion with the Division and Mr. Boatenhamer at the site, that was on a Wednesday, as I recall, and I reviewed the geology again, and by that Monday, I had determined that we didn't have a problem moving it. I never expected that we would, from my recollection, but I just wanted to double check.

Q. Does the change in the proposed location affect at all the notice that was provided? Because the notice went out based on the original proposed location.

A. Well, we obviously knew that if we moved the location 600 feet, basically, from the proposed location, that that one-mile circle would shift somewhat.

So what we did is when we decided that that was a better location, we tasked MBF to go back to the courthouse withd this added little piece of the section and to determine if there were any additional parties that we needed to notice. And what they found is, indeed, that there weren't.

It does go a little further south, but it's still on the same land that is owned currently -- that is leased by Burlington, who was one of the original people that was noticed, and owned by the State of New Mexico, which was also originally noticed.

Q. Now, with the additional infrastructure, you mentioned you had to shift the fence line and so forth. Does DCP need to re-negotiate or amend its right-of-way with the State Land Office?

A. That's my understanding, yes. I haven't been directly involved in that, but I do know that there has been a filing of -- the payment of a filing fee to make that amendment within the existing business lease.

Q. Now that the location is finalized, this is something that can go forward with the State Land Office to get that amendment finalized?

A. Yes, that's correct.

Q. Let's move on to discuss the background of the Linam gas plant. Could you please just briefly give a summary of what the gas plant does and why it's necessary to treat or handle this H2S a certain way?

A. Very simply, the gas plant is a natural gas processing facility. It takes field gas, which now has the capacity -- it processes 225 million cubic feet of gas a day. That means that there are literally thousands of wells that feed this plant.

Those wells have -- in addition to methane and other components of natural gas, those wells contain CO2 and H2S. Many of them are what are called sour gas wells, and that's because they contain CO2 and H2S.

And in order for that to -- as part of the processing, this plant separates the various components of the hydrocarbons as products for sale, gas products. And then obviously, ultimately what it's left with is methane and hydrogen sulfide and CO2, which goes to a naming system. That is separated.

The methane is what we burn in our stoves at home. And the CO2 and H2S formerly at this facility went to a sulfur reduction plant, as I mentioned, and now, since 2009, has been going to the AGI Number 1 for injection.

Q. Previously, the sulfur reduction unit would emit -- how did that work? It would emit -- process the H2S and then transform it to sulfur dioxide; is that correct?

A. No. It would take H2S -- it would process the H2S, as you mentioned. But it converted the H2S to native sulfur, so actually to molten sulfur, and then it vented all of the CO2 to the atmosphere. It also -- sometimes when it was down, it had to flare, and that's when it would create SO4, basically, as an emission.

Q. So the reason that DCP moved to the AGI is because it would reduce emissions of CO2 and any flaring from that facility?

A. Yes. And because the SRU was an aging facility, it was difficult to have it meet the current air regulations.

Q. Mr. Gutierrez, you prepared a presentation today; is that correct?

A. Yes.

Q. Let's turn to the first page of your presentation. Please give us an outline and a summary of what you're going to talk about today, as far as this new application goes.

A. Yes. Basically what we're going to go over today briefly is I will review the operational history of the Linam AGI Number 1 very briefly and the events that led to its workover in May of 2012.

I will then discuss the justification for a backup or a redundant AGI well, which is what we're proposing as AGI Number 2. I'll review the current injection limitations and requirements, because we're not asking for any changes at all in the currently approved requirements for the AGI Number 1. All we're looking for is another way of getting gas into the same zone.

I will also summarize the geologic setting in the injection zone, even though those things were all well covered in the original permit hearing.

I will talk a little bit -- this was the third well in New Mexico back in 2005. There's been a lot of work done on AGIs since that time. And therefore, there have been some thoughts about how to improve and obtain a better overall design. And those have been incorporated into this proposed well, and I'll talk about those.

I'll talk about the protection of nearby production and water wells and how that is achieved by the design of the Linam AGI Number 2.

I'll review a little about the H2S contigency plan and the context of what changes might be required in that plan as a result of this additional well.

And then I'll just review this overall operational and environmental benefits of the installation.

Q. Your next slide kind of gives a brief history and breakdown of the operations of the AGI Number 1; is that right?

A. Yes, sir. I apologize for all the text on this slide. It's more for the benefit of the Commissioners to be able to review. But I will go over this stuff briefly.

As we mentioned originally, this Linam AGI Number 1 was permitted in 2006 after a public hearing in front of this Commission, and it was completed in the Lower Bone Springs. It's perforated from 8,710 feet to approximately 9,100 feet. The well began injection of treated acid gas in 2009, the end of 2009.

This order has been modified quite a few times because of -- the original order had some conditions that became not applicable down the road in terms of some policy changes that the OCD had relative to the requirements for discharge plans at gas plants. So it's been modified several times, the most recent time being in July of 2011, where I testified in front of this Commission.

In late 2011, in fact, about this time last year, when the original permit was issued for this facility, there was a requirement that an MIT, Mechanical Integrity Test, be completed every five years for this particular well.

During the intervening period from when this well was originally approved and last year, there were a number of things that transpired within the agency that made the Division feel that it was more appropriate to require MITs every two years for acid gas injection wells, so DCP received a letter at some point.

Whenever the Division made that determination, they notified everybody that operated AGIs that now they're going to be on a two-year schedule. So that two-year time frame was coming up in December of 2011, because the injection began in December 2009.

So as part of the preparation for doing that MIT, the staff at DCP, I believe Mr. Kelly Jamerson and Mike Betz, who was the acid manager at the time, and Kelly, who was the engineer overseeing the AGI facility at the time, approached the Division office in Hobbs and spoke to Mr. Gonzales regarding the preparation for doing this MIT, which would have to be witnessed by the Division.

And in that process, of course, they discussed, what do we need to do to do the MIT? And what the Division suggested is that they needed to bleed down the pressure on the back side, which is the normal process you do for these MITs. You bleed down the pressure to zero on the back side, you pressure it back up to 500 pounds, and then you look and make sure that it does not vary more than plus or minus 10 percent of that pressure over the half-hour time period of the MIT test.

So in order to do that, they were told, "You've got to get pressure off the back side, and then you're going to have to raise that pressure up and do this procedure."

When DCP went out in the -- I think it was probably roughly around December 15th or in that time frame, to bleed the diesel from the back side to conduct the MIT, what they found is that, unlike the behavior that you would have when you have integrity or when you don't have a potential problem with the well, the pressure on the back side did not go down. Even after they had bled some relatively -- what I would have determined would have been a sufficient amount of diesel, roughly about a half a barrel or so, they noticed that the pressure didn't go down significantly.

So they re-approached the Division and said, "We're having this problem."

And the Division said, "Well, if you bleed down the pressure at least to 100 pounds and then bring it back up, that's probably sufficient."

So they went back out there, I think that same day or the next day, and continued to bleed approximately six barrels of diesel. Now, remember, there's probably about 160 barrels of diesel on the back side. But they bled off about six barrels, and the pressure still didn't go down.

So at that point -- I was not really aware of those things going on between the Division and DCP at that point. But I got a call on about December 16th or so from DCP saying, "Look. Here's what happened when we tried to do this -- prepare for this MIT. I think we may have a problem here. What do you think?"

I said, "Well, it doesn't sound good to me. But I feel like I need to look at the data for injection, the injection history, basically; annular pressure; the injection pressure; the temperature." Because you can get some really funny behavior on the back side of these wells when you really don't have a problem, but it could indicate that you have a problem.

So when I looked at those data -- I was provided those data probably the next day, and then I spent the weekend analyzing those data for the next couple of days -- I thought I recalled it being over a weekend.

But anyway, then on about December 18th -- and I know that date firmly because it happens to be my sister's birthday -- on that day, I contacted DCP and I said, "I think we have a potential problem with the well. We may have either a tubing leak or a packer seal leak, and I think it would be appropriate to report that to the Division."

Q. So that's what precipitated the December 19th letter, which we'll learn about later in this hearing, from DCP to the Division, indicating that there was a -- had been identified a potential problem?

A. Right. In fact, I drafted that letter. So it was my basic determination that we had a potential problem there. I worked with DCP to draft that letter and to get it to Mr. Gonzales, with the Division, to start the process of how we would deal with this potential problem.

At that point, as I'm sure Commissioner Bailey may recall, over the holidays, we had a number of conference calls with the Division that involved Mr. Gonzales, Mr. Jones, Director Bailey, and Ms. Gerholt, to determine what was an appropriate way to go forward to correct this problem.

The Linam Ranch plant had a turnaround

scheduled for April 2012. One of the key things that both DCP and the Division wanted to avoid, if it could be done safely, was to avoid an unplanned shutin of many of these wells. And frankly, also, in order to be able to obtain the spares that are required -- that we wanted on hand in order to do a workover, that was going to take some time. These things are not off-the-shelf items that you can just purchase.

So the question was: How can we assure that we can continue to operate this well safely in this interim time between now, which was January of 2012, to April of 2012, when we knew we could work it over?

The result of those discussions was basically the ACO-275, which was a compliance order that DCP and the Division agreed to, which had very stringent operating requirements for the well in this interim period between the time when we negotiated this and the workover.

And I recall very specifically, at the time when we were discussing this, that Director Bailey, in her capacity as the Director of the OCD, asked me on the phone, did I feel that there was -- if we implemented this approach, did I feel that there was any potential danger to public health or the environment as a result of this operation for this four-month time period?

And I said no, that I felt confident that the well could be operated if it was done under these kinds of parameters.

And those parameters were parameters that limited the maximum injection pressure to a pressure of 1,200 pounds, which was significantly lower than what is the approved maximum operating pressure in that well. And it also required maintaining at least 200 pounds' difference between the back side and the tubing pressure in that well.

And in addition to that, it required weekly reporting of all of the three major parameters related to the operation of the AGI well: The injection pressure, injection temperature, and annular pressure, and the injection rate. Four items.

And those were then -- those data had been collected all along, as required, but they weren't reported to the agency because they're not required to be reported. They are just collected. In fact, those data are not even collected daily. They're collected like every 15 or 10 seconds, so it is a mountain of data. I got the hourly data for that time period that I reviewed over the weekend, and that's how I determined that there might be a problem.

But anyway, those data were then reported for the next 16 weeks. We prepared a weekly report to the Division that was given to Mr. Gonzales and Mr. Jones that tracked and showed exactly what those operating parameters were for that well and demonstrated that we were meeting the requirements of that order.

Then in April, as planned, we began a workover of the well to now figure out what was the real problem with the well.

Q. So turning to your next slide, just give us a summary of what your analysis revealed about that issue during the workover and what happened during the workover.

A. During the workover -- the workover began on April 27th of 2012. As the Commissioners may be familiar, but just to go over what happens during a workover, the idea is we're going to pull the tubing, figure out if there's a leak in the tubing or in packer seals. And in order to do that, we first have to do what is called we kill the well.

So that means is we pump brine down the tubing. We stop injecting acid gas. We pump brine down the tubing and displace all the acid gas that is in the tubing back into the formation and put what's called a blanking plug beneath the seal assembly in the packer. And that allows you to now isolate the formation, so you can't get acid gas coming back up at you when you yank the tubing out of the packer.

You then yank the tubing, literally. You physically pull it out of the packer seal assembly and you run out all of that tubing. In the case of this well, it's 8,650 feet of tubing. So we did that. We ran out all of that tubing.

Now what you're left with is basically the diesel that used to be in the annular space has now filled up the inside of the well casing. And you have brine in there, as well, that you had in the tubing that now is in the well casing. So the requirement is to then circulate all of that out.

The reason why is -- we had a specific H2S contigency plan, not the one for operating the well, because a well workover is not a normal well operation. That's something that you have to do when you have to repair a well. So we had a specific H2S contigency plan.

We had Total Safety out there. That's not an acronym, that's the name of a company. Total Safety was the company that was doing the H2S monitoring and everything for the workover process itself to make sure that our own employees and the drillers and everybody was maintained safe.

When we did that, we had a separator --

because we knew that we had a potential for having acid gas in the annulus of that well because we knew that we had some possible communication between the tubing and the well itself. So we had this separator on hand, and we were slowly circulating the diesel out of the well. And at one point on that first day, the 27th, we had -- except the way that works is you take that diesel out, you run it through a separator, and you remove any acid gas that's in the diesel. It is routed to a flare right there, a portable flare that is associated with the workover unit, and you incinerate that acid gas.

What happened is that that flare that was there was basically overwhelmed by the CO2. When we got a little burp of acid gas that came out of the annular space of the well, it blew out the flare that was associated with the separator, which caused a release of acid gas right there at the workover site.

As a result of that, we implemented -- we shut down the operations. That release lasted maybe two minutes. It was a very small amount of largely CO2, but some H2S was released at that point.

And we shut down the operations for the night until we could determine what we could do to make sure that if we had any additional acid gas, which we thought we might have a little bit left still in the annular space there or now in the casing, how we would make sure that that flare would operate appropriately.

And what we did at that point is we actually re-routed the plumbing from the flare that had come with the workover unit to the main acid gas flare at the facility for one reason and one reason only. And that's because the main acid gas flare has a fuel assist.

The small flare that comes with the workover unit has no fuel assist, so that's why it got blown out. The acid gas flare that the facility has has a fuel assist that allows it to basically continue to burn even in high CO2 concentrations. As everybody knows, CO2 is a fire extinguisher, so that's what happened.

So the next day, we restarted the operations at about 6:00 a.m. in the morning. After we re-routed this stuff and we removed the rest of the fluid from that inner space, it was routed to the flare, and we continued with the workover.

Q. After doing the workover, you continued to look at the situation with the AGI Number 1. And you did an analysis of what happened, what caused that communication between the annular space; is that correct?

A. Yeah. Let me just finish with the workover, because there are a few things that are important to note.

Q. Sure.

A. We had already now pulled the tubing, so we looked at the tubing. And lo and behold, what did we find? What we found is that there had been corrosion in that tubing in the bottom -- it was worse in the bottom joint of that tubing, the first 20 feet above the packer, but we had some corrosion for the next two joints above that.

So we had corrosion in the lowermost 60 feet of tubing, and we actually had holes in the tubing from -- that communicated the acid gas that was flowing down the tubing with the annular space above the packer. It stayed contained within the well, but it was out of its designated place, which is inside the tubing.

We also carefully examined all of the tubing and the subsurface safety valve and determined that there was no visible evidence of corrosion in the upper portion of that tubing and no evidence of any damage to the subsurface safety valve, which was operating properly, so we put all that aside.

And we had all new tubing out there that we had purchased in the interim, in that time frame between January and April of 2012. We also had a new packer because we thought, if there's a problem with the packer, we may have to set a new packer out there.

When we pulled out the tubing and we recognized that this corrosion had caused a leak in the tubing in the bottom of that well, we obviously knew we had to replace the tubing, and we also did a casing integrity log at that point. We ran a casing integrity log to see if the production casing itself had become compromised.

And what we found is that while we did detect some corrosion in the lowermost 40 feet or so of that casing, it had not lost its integrity. And there had been no leak outside of the well, but we had this little compromised section of casing above the existing packer.

And I was concerned, and I said to DCP -- and this was all done in cooperation, very close. I mean literally hour-by-hour communication between us and the District Office while we were doing the workover. They had their people out there periodically. Mr. Gonzales was out there to see the tubing when it was pulled, and he could see for himself what the corrosion looked like.

So we still didn't know the cause of what happened, but we knew what the physical problem was. My suggestion as to how to fix it was to do the following: Replace the tubing and put a new packer, stack it above the other packer -- because the packers that we use in these wells are permanent packers. You can't remove them.

So my thought was, okay, let's get a seal assembly below a new packer that will actually stab into the old packer. And we'll stack a packer right above that old packer that will isolate that piece of casing that had some corrosion, and so we won't have a problem there. And then we'll put all new tubing in the well. So that's what our intent was.

We went and asked Mr. -- we submitted a C-103 that said that's what we intended to do. We talked about it with Mr. Gonzales, and he agreed that that was a good approach.

So we go back out there and we start to run the new packer. Unfortunately, the new packer actually failed on the -- while trying to set it. This was a very disturbing and expensive situation.

We were running the packer on the new tubing, or on a work string, actually. We were running the packer down, and we were going to set it at 8,600 feet. At about 850 feet, the packer set. The packer itself failed. It set at 800 feet. So now we have a packer stuck at 800 feet in the well.

We had to remove that packer. That took about another four or five days. We had to mill it out. Because they're permanent packers, we had to mill it out.

We then had to fish -- what holds a packer in place are these slips that look like Hershey bars with ridges. They're made of steel. There's six of them. Those dropped to the bottom of the hole when we had to mill out the packer. We then had to fish those little candy bars of steel out. It took about three days to do that. And now we were back to the same situation.

We've got -- we know the packer we have in the hole is still good. We have this area of compromised casing that is above the packer, but we have new tubing. We need to get the well back on line. Let's put new tubing in, and then we'll do an MIT. And if it passes, then we know we need to monitor it closely, but that we still had integrity in the well.

So we submitted a new C-103. We discussed it with the Division. And at that point, we came up with that approach. We ran the new tubing, stabbed it into the old packer. We did an MIT at 3,000 psi. We tested the tubing and the annular space to 3,000 psi, had no problems there.

So we went back. And we said to the Division, "Okay. At some point in the future, we're going to want to work this well over and put a new packer, a stacked packer, just like what we said, to avoid any potential long-term problems with that casing."

But unfortunately, these packers take four or five months, when you order one, to get one. So we couldn't just get another one out there and try to redo it again. As a matter of fact, we looked all over the world literally to see if we could have a packer flown in while we had the well down, but we couldn't.

So we came up with an approach. We did this high-pressure MIT to assure that that casing had integrity, and we came up with an approach with the Division where we could continue to operate the Linam AGI Number 1 safely.

And to do that would require the reporting now on a monthly basis to the agency of the injection, because we had to repair the tubing leak, obviously. And it would require monthly reporting, similar to the weekly reporting that we had done, and we would be required to do an MIT on the well every six months. The first one was done right at the workover. The second one was completed last month, in November.

Then we went in to trying to do essentially a failure analysis or a determination of what caused the original failure in the tubing. And that's what we proceeded to do after we got the well back up and running.

Q. Mr. Gutierrez, just to recap, so what you determined, based on your analysis, was that there was a communication between the annular space and the tubing, but that the casing integrity log that you ran indicated that the casing integrity remained sound; that the casing actually contained whatever gas leaked had into the annular space because -- you know that because it's burped to the surface; is that correct?

A. Yes, sir.

Q. And also, that cement bond log that you ran indicated that the entire cement bond along the entire casing was sound. So that indicated to you that the formation did not receive any of the leaked acid gas; is that correct?

A. Yes. And furthermore, as importantly as the things that you mentioned, we did a 3,000-pound MIT test for an hour of that casing. So I mean that is a much higher pressure than that casing would ever experience under normal circumstances, and it did not leak.

Q. Thank you, Mr. Gutierrez. And real quickly, you said you did an analysis also of what went wrong?

A. Right.

Q. Can you briefly summarize for the Commission what it was that you determined was the cause of the communication between the annular space and the tubing?

A. Yes. As Mr. Gonzales will remember from when he looked at the tubing -- and I actually brought some of that tubing up here and showed it to Mr. Jones and Mr. Ezeanyim, because I think just in the interest of looking at that, because that tubing that had failed, we then took all of the tubing that had failed -- it was a multistep investigation.

The first thing we did was take all of the visibly-affected tubing and send it to two metallurgical research companies in Houston that sliced the tubing up. They did metallurgical analyses to try and determine the cause of the corrosion, whether it started from the outside of the tubing coming in or the inside of the tubing going out. And so we did a detailed metallurgical analysis.

We still had all of the tubing from -- that had been pulled out of the well. And we were interested in trying to see whether there had been corrosion anywhere else along that tubing, so we did an analysis. We had a tubing inspection company that came out and inspected all of the tubing. And in fact, what they confirmed was it was only that lower portion of the tubing that had experienced any degree of corrosion.

The report from the metallurgy companies that came back to us indicated basically three things: First, that there had been -- there was pitting inside the tubing that had not fully penetrated the tubing. In other words, it had not made a hole in the tubing, but was essentially eating out the inside of the tubing in a couple of locations.

And then there were holes that had formed in the basal portion of that tubing that had connected the inside of the tubing stream with the annular space.

And then there was also corrosion from the outside in, once that inside corrosion had taken place. Because obviously what happened was we had some corrosion happening from the inside. And then once a little bit of acid gas got into that annular space, we had much more corrosion coming from around the outside of that tubing back in just because -- even though we had diesel in that annular space, when you have an 8,600-foot column of diesel, even under normal -- and the best diesel you can get, still has a very small amount of water in it. So we probably had some emulsified diesel at the base of that tubing zone that reacted with that acid gas and caused further corrosion of the tubing.

We also determined that the subsurface valve, the tree -- we had the tree completely taken apart. It had not experienced any corrosion. Neither had the subsurface safety valve or neither had the upper 8,600 feet, roughly, of tubing out there.

But we found that was the indication, from the mineralization that occurred, of where the corrosion occurred. What the metallurgist told us is, "There's no way this could have happened if you didn't have free water inside that tubing to begin with."

And then when I went back and looked at all of the data that I had looked back in December of 2011 and looked at all of those data, compared to the data of when we had improved the temperature control of the operation in that interim period between January and when the workover was, what I saw is that there had been very large fluctuations of temperature in the injection stream during the operation of the AGI prior to December 2011.

And what I started doing was looking at the phase envelope of the acid gas inside the tubing. And what I determined is that these rapid fluctuations in temperature ended up causing free water to actually come out of the acid gas inside the tubing and basically run down the inside of the tubing and create a corrosive condition at the bottom.

So we identified really the ultimate cause of the problem. There had been poor temperature control of the injection stream.

In addition to that, one of the other recommendations that was made even before we put in the new tubing while the workover was going on was that we should add both biocides and corrosion inhibitors to the diesel fluid itself before we put it back in the -- I mean to the new diesel that we were going to put in the annular space.

So we added corrosion inhibitors to that diesel. We added biocides to that diesel. We put in the new tubing. We put the old subsurface safety valve back in. We put the old tree that had been worked over back on. And we proceeded -- I proceeded then to tell DCP and inform them that we really needed to have a much better control on the temperature of the injection.

And we already thought this was a potential issue, but now it was confirmed as having been the cause of the problem.

So if you look at the operation of that well since January of 2012, DCP has done an excellent job, and Mr. Boatenhamer will testify to what they did operationally to fix this temperature control problem.

Q. You mentioned that there were wide fluctuations in the temperature. But you could get condensation even if the temperature fluctuations are within a reasonable parameter; is that correct?

A. Yes, absolutely. What we were trying to do is to understand what was the range that was reasonable to maintain. Because you can't keep it exactly at the same temperature all the time. But what had been happening is it had been fluctuating from like 65, 75 degrees to like 115 degrees, the injection temperature.

Now our fluctuations of injection temperature are in the range of maybe 6 or 8 degrees. And that's not enough to really cause condensation to take place.

Q. Based on all this analysis and your discussions with the Division, looking at your Slide Number 5 of Exhibit Number 3, can you summarize the justifications for having a second injection well?

A. Yeah. Basically, as we were doing this workover, we were thinking, "Oh, my God. All these wells are shut in. The plant is down. People are probably flaring out in the field or venting H2S. This is not a good situation."

And now we knew that we were also going to have to work over AGI Number 1 again to put the stacked packer in. So that means that another two or three weeks when we finally can get that new packer. The plant would have to be shut down for another two to three weeks.

So I think it was kind of an organic discussion that developed while we were out there. I remember very clearly standing around this corroded tubing with Mr. Gonzales, from the Division, and Mike

Betz, who was the acid manager for DCP at the time. And we were talking about this, and we were talking about whether we should use different materials in the tubing or whatever.

And Mr. Gonzales, at the time, said, "Why don't you guys just have another well out here?"

I said, "Yeah. Well, I mean we certainly could do that. That's a pretty expensive proposition."

But the more we thought about it, you know, it's not, in the end, as disruptive or -- it would be a real improvement to the AGI facility to have another point of entry for that injection, so that if we ran into a problem, or certainly when we had to work over the Linam AGI Number 1, that we could continue to operate the plant. So that was the fundamental genesis of what we determined.

What we determined is that the overall AGI facility would have a much greater reliability. It would reduce flaring events at the plant. It would also prevent a situation where you would have to shut in all these wells by having to shut down the plant in an unplanned shutdown. So that's when we started thinking about a second well.

I recommended that that's something we look at, that my client examine. And they tasked us to take a

look at that. And the decision was made in the summer of this year to go ahead and proceed with developing a new well.
Q. You point out that the facility has other operational redundancies built in, but the well is the one that there is no redundancy existing now. And that's one of the major justifications for this; is that right?
A. That's right. It's the critical link.
Q. The new application doesn't seek to change any of the existing conditions under the order, is that correct, same injection pressures?
A. That's correct.
Q. Looking at Slide Number 6, is this sort of a summary of the existing conditions and limits imposed under the order?
A. Right. The current order requires a maximum allowable operating pressure of 2,644 psi, with a specific gravity of .8 for the TAG. That MAOP is -- we don't need anything different than that.
We also have no injection rate limitation. And that is appropriate in this case because this is such an excellent reservoir, and because there isn't really a need to inject more H_2S. But what the plant has been seeing is an increasing concentration of CO_2 in the inlet gas, so we could have some fluctuations in the injection

rate as a result of those fluctuating CO_2 concentrations.

So the bottom line is we're not proposing or requesting that the Commission change any of the current approved parameters for the AGI facility.

Q. Now, as a result of the workover and the issues with the AGI Number 1, were there some additional requirements imposed by the Division through C-103s that you can touch on?

A. Yes. We are currently operating under an approved C-103 that requires monthly analysis and reporting of these key injection parameters. Those are reports that -- I get those data, hourly data. Actually, I get the data for every like 15 minutes of -- for every month. I analyze those data, and I report them to the Division usually the first week of the month for the previous month.

And we are also required to do an MIT on the well every six months. We just did one on November 14th. It passed fine.

Then at some point in the future, we will have to add this stacked packer arrangement to address that one portion of the casing that had been compromised.

Q. Thank you, Mr. Gutierrez. Now, let's move on to the geology and the setting for the proposed injection.

CHAIRMAN BAILEY: Is this a good place for a 10-minute break?

MR. RANKIN: Absolutely.

CHAIRMAN BAILEY: Why don't we take 10 and come back at 20 until?

(A recess was taken.)

CHAIRMAN BAILEY: Shall we resume?

MR. RANKIN: Thank you, Madam Chair.

Q. (By Mr. Rankin) Mr. Gutierrez, right before the break, we were about to enter into a discussion about the geology and the setting for the injection of this acid gas into the Lower Bone Springs formation, the formation that's already been approved by the Commission for these purposes.

Can you briefly summarize for the Commission the geology of the Lower Bone Springs and the surrounding area?

A. Sure.

Q. This is on Slide Number 8 of Exhibit 3?

A. Yeah. Basically, the detail on the geology was all presented in the original hearing, and so I'm going to try to abbreviate it now to the extent that we can.

But basically, the Lower Bone Springs is a carbonate -- detrital carbonate formation draped off of the Central Basin Platform, as I described earlier. It is overlaying by approximately -- by a portion of the upper Bone Springs and a series of interbedded zones within that and into the Abo above it that constitute essentially about a 3,000-foot caprock or layered sequence, which serves as the caprock for the reservoir.

The Lower Bone Springs has proven to be a much better reservoir than we originally anticipated. As a matter of fact, one thing I failed to mention when we were talking about the workover is that when we killed the well, it went on vacuum, even after three years of having injected acid gas into that well.

So clearly it is an underpressured zone, one that is fully capable of the kinds of rates of injection that we have there. It's got a good caprock. There's a whole combination of geologic conditions and well design factors that we'll mention in a little bit that provide full protection of fresh groundwater in the area.

And there are no new wells that have been drilled into that injection zone within a mile of the Linam AGI since the last permitting.

Q. Your next slide is sort of a representational overview of the geology. Can you review that briefly?

A. We talked about this. It's a -- just so that you can see it visually, this is the Central Basin

Platform right here. This is the Permian Basin. The Central Basin Platform is this area here, with the Delaware Basin to the west, as I mentioned, and the Midland Basin to the east. And the plant is located off the north end of this Central Basin Platform.

And in cross-section, it kind of looks something like this. As you go from east to west or, in our case, from south to north here, you drop off into that Delaware Basin. And you basically have this Lower Bone Springs right here, and you have the Abo terrigenous sediments that provide the caprock right behind the Abo reef, which is located further to the west of where we are.

And from there, you go into the normal Permian -- strata of the Permian Basin, including the Glorieta, the Grayburg, San Andres, Seven Rivers, Queen, from there to the surface. And then you have the Dockum Group and the fresh water zones above that.

Q. And the next slide is a more detailed geologic representation of the area. Can you briefly review the features of this map for the Commissioners?

A. Sure. This map was included in the C-108. It was also included in the original C-108. And this was based on the seismic work that we had done and all of the well logs in the area.

What you can see is there's this what we call the Abo Productive Fairway. It's this north/south trending line of Abo producing wells that goes west of where our AGI facility is located. It peters out about here, somewhere between where the plant is and where the AGI facility is.

And this was the area identified in green that was the area that was most likely to be productive for an acid gas injection reservoir. And in fact, within this box is where we had identified originally would be the best location for an AGI there. We identified two zones originally. One was what we call the Brushy Basin, which is the Glorieta equivalent in that area, and the Lower Bone Springs as potential candidates.

As it turned out, when we drilled the well, we opted for the Lower Bone Springs and to keep the Brushy Basin behind pipe. Which, as it turns out, is another important feature that protects fresh water here, because it is a grossly underpressured and thief zone in this area.

In fact, when we drilled the AGI Number 1 -- this is what I'm saying. When we drilled the well and got data from the new well, we learned a lot more about the reservoir and the geology out there.

But in that zone, which is about 5,000 feet, we lost circulation for two and a half weeks when we were drilling the well. So it was taking everything that we could give it, any kind of loose circulation material, to -- so basically, that zone also provides -- it's above the caprock, and it provides another significant protection for anything that could have possibly come up.

You see a couple of faults in this area. These are all faults that are below our injection zone. They peter out before you get to the Bone Springs. And we identified those based on the seismic.

Q. Now, based on your analysis originally and three years of injection and subsequent study, have you confirmed your original analysis that the Lower Bone Springs is an appropriate reservoir to receive this acid gas injection at the volumes and pressures that you originally determined?

A. Yes. It's below all the existing potential oil and gas production. It's got an excellent caprock and geologic seal that contains that gas. It's got very compatible fluid chemistry. It's isolated from fresh groundwater. It's laterally extensive and permeable and, in fact, underpressured. And we've got about 25 feet of gross porosity about 14 feet after you consider the saturated irreducible water.

And we anticipate a radius of injection at 7 million, which is currently what we anticipated would be the maximum that would be injected. It depends on the CO2, but that's a good working number. And that is -- would result in about a little less than half a mile after 30 years. We presented this in detail in the 2011 hearing, as well.

Q. Based on the January 2008 step rate test, which is presented in your next slide, maybe you could review for the Commissioners what this step rate test has allowed you to conclude?

A. Basically what it allowed us to conclude is that the MAOP that was set for the well was well under the potential fracture pressure. And in fact, what we see is that our projected range of injection rates originally were in here, that we would be seeing pressures around 4,500 feet of bottomhole for the well.

And as it turned out, what we have seen is, frankly, that it's a lot better than this. I think we're seeing those kinds of pressures, 4,500 or so bottomhole pressure, and actually with injection rates that are more like around 5 million. And we're seeing that we're able to do that at less than 1,500 psig of injection pressure, which is -- it just speaks to how good the reservoir is.

Q. Mr. Gutierrez, your summary of this step rate test is on the next slide. But in sum, your conclusions are depicted here; is that right?

A. Basically, we could take maybe as much as 20 million cubic feet a day into that zone, and we would not reach the MAOP, and we would not reach the fracture pressures. But that's way above what we anticipate putting in there. It just means that we've got a lot of room to put stuff in.

Q. Mr. Gutierrez, in the previous slide you mentioned that you calculated a radius of injection of approximately .47 miles over 30 years. Do you have a slide that discusses the methodology behind that analysis?

A. Sure.

Q. That's this next one here; is that right?

A. Right. It's calculated down here, in the area that's highlighted in yellow. This was included in the C-108.

It's basically our radial model of injection for this well. Assuming that that injection was to take place at a maximum 7 million rate for 30 years, we wind up with about .47. And what this lays out is the overall pressure and composition of the injection stream and how we calculate that.

Q. The next slide, Mr. Gutierrez, that basically is a map depicting the projected range of the radius of the injected area?

A. Yes. This large blue circle is just a one-mile circle around -- just for reference, a one-mile circle around the AGI Number 1. This is kind of a skewed plume depiction after 30 years.

This interior one was when we did it at 4.6 million for 30 years, and this was 7 million for 30 years. You can see it doesn't change a lot. Because what happens is as you get farther and farther out from the initial injection, you encompass a lot more area for every little bit of radius that you add.

So you can see there that we anticipate no more than about a half-mile radius.

Q. In prior testimony before the Commission, you testified about your expectation that the injected acid gas would stay in roughly that location. Can you just briefly summarize for the Commission your basis for that belief?

A. Yeah. Basically, we've got a pretty homogeneous reservoir in that area that is taking acid gas at much lower pressures than what we originally anticipated. It's got a very good caprock. We confirmed that by not only the detailed geophysical logs that we did of the well when we drilled it, but we also did core analyses of the caprock and the injection zone. So based on all of those data is how I concluded that that was an excellent reservoir with a good caprock.

Q. Now, your next slide, Number 16 of Exhibit 3, is just a summary of what we just discussed and why the injection is appropriate?

A. That's correct. The only point that I would make on this slide that we haven't talked about is that the new well, I just want to emphasize it adds no additional capacity. And it's expected to operate exactly as the Linam AGI Number 1 does, pursuant to the current order and its amendments, but it does also represent some significant design and monitoring improvements over the existing AGI Number 1.

Q. We'll get to those in just a little bit. You mentioned earlier in your testimony that there is no existing production of oil and gas within the Lower Bone Springs; is that correct?

A. Yes.

Q. So the production -- the injection zone would be below any existing production; is that right?

A. That's correct.

Q. Are there any oil and gas wells in the area within one mile?

A. Yes, there are quite a number of them. There's about 19 wells within a mile. Most of them are plugged and abandoned. There are some Abo wells. All of the wells -- all of those 19 shallow wells are completed well above the Lower Bone Springs injection zone, and there are only three wells that penetrate the injection zone in the area.

There were only two when we did the application originally. And then, of course, now we have one that we drilled there, the Conoco State Number 1, which is located about a mile away, a little less than a mile away, and Goodwin's Number 3, as well.

Those are plugged and abandoned wells that have been plugged for a long time. We reviewed the plugging records and felt confident about the integrity of those wells when we did the initial application, and there's no reason to question any further whether they have a problem.

Q. In your opinion, based on your analysis, there's nothing that's changed from the time the original application was granted with regards to these two existing wells?

A. No, absolutely not.

Q. On Tab 8 of Exhibit Number 4 is the Goodwin Number 3 well, which was in existence at the time the original application was approved?

A. Yes.

Q. And Tab Number 9 is the Conoco State Number 1 well?

A. Right. These were provided in the C-108 application, both the original one and the current one.

Q. Your next slide, Mr. Gutierrez, Number 18 of Exhibit 3, represents the current design and plan for the AGI Number 1?

A. Yes. This is the AGI Number 1 as it's currently constructed. It is basically -- as I mentioned, it has three strings of casing that are cemented to the surface. We have a packer set at 8,650. We have new tubing in the well. We have a subsurface safety valve. We have that zone of compromised casing that we talked about that had been affected by corrosion, but did not experience a leak, which is down immediately above the packer here, which we intend to isolate when we put a new packer in. And we've got L-80 tubing that we replaced in May of 2012. And like I mentioned, we inspected and re-worked the tree and the subsurface safety valve and put those back in the well.

Q. For the benefit of the Commissioners, Tab 10 of Exhibit 4 is the table indicating the cement and casing details for each of these wells; is that correct?

A. That's correct.

Q. As you said, nothing has changed to alter your opinion that the completion and casing of these wells would compromise any fresh groundwater sources or impact their production?

A. Absolutely not.

Q. You reviewed just briefly the wellbore schematic for the AGI Number 1. What are some of the lessons learned -- we discussed some of these at length -- but just briefly, some of the lessons learned from the design of the AGI Number 1?

A. The first and most important one is the importance of temperature control in the TAG stream to prevent any free water in the tubing.

The second added feature is adding some corrosion-inhibited diesel, corrosion inhibitors and biocides to the diesel in the annular space. We could use some improved materials in the casing and the tubing that will provide additional protection against corrosion, in case we should somehow not be able to maintain pressure or have a problem with that.

Also, the corrosion is primarily an issue only in the casing and tubing immediately above the packer. That's another thing we have learned. So we have modified the design of Linam Number 2 to add some corrosion-resistant materials in that area.

And then we've also incorporated just some general improvements in how we design and operate these wells since 2005. And we'll go through those when we get to the Linam AGI Number 2 design.

Q. That's been eight years. So of course, you think there will be some design improvements and technology and so forth?

A. It's a rapidly-changing field. In fact, I've been working for the last four months with a group of stakeholders with the Division to develop new AGI regulations, because it is a rapidly-changing field.

This is a technology that has been in use since -- for about 25 years. It started primarily in western Canada and -- yeah, there is a lot of work being done and a lot of -- a better understanding of how these wells work and how to improve them.

Q. But your design enhancements for the proposed AGI Number 2 don't indicate any failing or problem with the existing AGI Number 1?

A. No, they don't. They're just real improvements in the design.

And one of the other things that -- I don't want to let the cat out of the bag early. But when I talk about one of these improvements, one of the things we intend to do that has not been done on any AGI yet in New Mexico, and I think will give great data, is that we're going to put a fiber optic line down into the reservoir and be able to monitor bottomhole temperature and pressure real time during the whole injection process.

Q. Let's go to your next --

A. That's a big addition.

Q. -- and talk about some of those elements here.

A. We're going to use essentially the same tubing material and casing material from about 1,000 feet above the injection zone to the surface that we have in the AGI Number 1.

But just for added protection, we are going to put a specific corrosion -- additionally corrosion-resistant, much more than just L-80 casing, in the thousand feet that go from the -- of the tubing from the packer to 1,000 feet above. We're going to do that in the tubing and the production casing all the way through that injection zone and up through that same level.

We're going to use a Sumitomo 2235, which doesn't mean anything to anybody, except for the fact it is a very high-nickel casing and tubing that is significantly more corrosion resistant than the normal sour gas tubing that would be L-80 type tubing.

We're basically going to use the same

subsurface safety valve and packer, et cetera, because we feel that there really hasn't been any substantial change in those, or the tree.

We're going to use a little bit different connection in the tubing, which is a VAM connection, and in the casing, versus a flush joint. And that's just because it makes it easier to install, and it has the same integrity as a flush joint seal.

So those are -- and then as I mentioned, we're going to put downhole instrumentation in that well, a fiber optic line, that will allow us to have real time measuring of that pressure and temperature in the injection zone, which will just give us a better understanding of how these wells work. I'm really glad that DCP is willing to do that, because it will provide us some good data going forward.

And then the surface facility design doesn't change much. It just adds this new well. But one of the things that Mr. Boatenhamer will testify to is that we did make a fundamental change.

The problem that was causing the temperature control was that these temperature controls, the actual box that controlled them, if you will, was mounted on the compressor skid, and it was subject to a lot of vibration from normal operations. And that was partially the cause for not being able to control that temperature. So that's been completely moved already. That was done last spring and has really improved the operation.

Q. Now, this next slide is just a graphical representation of those design elements that you already discussed?

A. Yes. And I want to emphasize that there are just a couple of minor changes that have been added here, if you will, to this design that were not in the original C-108. And those I've already discussed.

That's basically that we're going to put that corrosion-resistant casing all the way up to -- the production casing will go to inside the intermediate casing. And we will extend approximately 1,000 feet of corrosion-resistant tubing above the packer, in addition to having the strings of cement, as normal, circulated to the surface for all of these strings.

One thing you'll notice that's a little different, and this is not really an added design feature for the well for the purposes of long-term operating of the well, but it's more a safety feature. It's going to improve the overall design, but it's really a safety feature for drilling the well.

Here's the situation: We know we're going to drill into a zone that we've been injecting acid gas into for three years, and we're going to do it very close to the original well. So what we're going to do differently in this well is we're going to take this intermediate string -- if you'll notice, this has four strings of casing, instead of three, which is what Linam AGI Number 1 has.

And the reason why we're adding that fourth string is basically, we're going to take the nine-and-five-eighths-inch casing all the way down -- right now in the Number 1, it's only down to 4,200 feet. Here we're going to bring it down to 8,600 feet, immediately above the injection zone.

The reason why we're doing that is one reason, a simple reason. That is that when we drill into that acid gas reservoir that we've been injecting acid gas into, we will encounter acid gas. We've got to keep that well under control while we're constructing the well. So for that reason, we're going to take that intermediate string, at a cost of almost $2 million additional, all the way down to 8,600 feet, because we know, as I mentioned earlier, that below the current 4,200-foot depth that we have the casing in Number 1, we encounter this lost circulation zone in the Glorieta. And our concern is that we might not be able to keep enough mud on that hole, open hole, to control the acid gas in the reservoir when we drill into that reservoir.

So what we want to do is have casing set already, before we ever penetrate that injection zone, all the way to the top of the injection zone, so it will facilitate us being able to set production casing with a minimum of safety concerns to the workers on the rig.

That was part of the original design that was presented in the C-108. The only difference that is shown here is the addition of these strings of corrosion-resistant casing in the tubing and in the casing, and then also the fact that we will be using this downhole pressure and temperature monitoring via fiber optic.

Q. In your opinion, will the design of the AGI Number 2 enhance the reliability and overall effectiveness of the AGI facility and the operations of the plant?

A. Just the fact of having a second well itself will significantly increase the reliability of the AGI facility, because it simply allows you to use one well while the other is being worked over and minimize any kind of flaring or shut-in events.

But clearly, we will learn more about this reservoir, that we've already learned quite a bit about, by having this additional instrumentation put in it. So yes, I do believe it will.

Q. Have you reviewed the six conditions that the Division has proposed be incorporated or being part of the requirements that DCP meet for this well?

A. Yes, I have.

Q. Do you have an opinion on those?

A. Sure. Basically, I think all of the conditions are reasonable. And we don't really have a problem with any of them, except for Condition Number 3, which relates to the monthly reporting.

My understanding is that the reason we were doing that in Linam AGI Number 1 is that it would be a temporary procedure to make sure that we're keeping that well being operated safely, an every-six-month MIT, combined with that monitoring, until we can stack another packer and finish and effect the workover that we had planned there. So I think that's entirely appropriate for the Linam AGI Number 1 until we complete that workover. I don't think there's any problem. We collect that data anyway.

But I think monthly reporting of it on a brand new AGI well is not necessary. But I mean we collect that data anyway, and it's certainly available for the Division to see at any time.

Q. Thank you, Mr. Gutierrez. Just a couple of quick issues. The source of the injection fluids will be the treated acid gas in the plant; is that correct?

A. It's the same source as the AGI Number 1.

Q. Have the constituents of that source changed at all? Are the components roughly the same, or how have they changed? What is the component makeup now of that --

A. The H2S concentration hasn't changed much. But what we're seeing in the inlet gas is some increases in the CO2 concentration, so we talked about this at the July 2011 hearing.

But right now the well -- the plant is running at about 225 million, which is its full capacity, and we're only producing about 5 million -- 5 to 5 and a quarter million a day acid gas, rather than the 7 million. However, it might eventually get to 7 million if we continue to see increases in the CO2.

But right now we're injecting roughly 88 percent CO2 and 12 percent H2S. If the CO2 concentration increases, then we'll probably wind up maybe at 8,911 or somewhere in that range.

Q. Is this an open or closed injection system?

A. It's a closed system. The Lower Bone Springs is a closed system.

Q. Let's move on to some of the fresh water issues that we've reviewed and analyzed. Are there any fresh water zones in the area of injection?

A. Yes.

Q. Can you identify those, please?

A. Sure. There's fresh water in basically three zones: Quaternary Alluvium, where it exists, essentially the alluvial unconsolidated deposits at the surface. And then below that, we're in a kind of transition zone. The Ogallala Aquifer is pinching out in this area. So in some locations, you have a little bit of Ogallala below the Alluvium and between the Alluvium and the Dockum Group, the red beds. But in other areas you have it going directly from the Alluvium into the red beds.

So we basically have three fresh water zones: The Alluvium, the Ogallala and the top portion of the Dockum Group. That lowermost of those would be the top portion of the Dockum Group, which is at about 300 feet. It would be the base of that fresh water zone.

Q. Your next slide, 22, of the Exhibit 3, is basically a review of how the AGI will -- how the geology in the AGI Number 2 will help protect fresh groundwater sources; is that right?

A. Yes. With all of these AGI wells, we work with two things. We use man-made features, i.e., the well design, to protect these fresh water zones and producing zones, and we use the geologic environment itself. Selecting a good location and the appropriate reservoir is key to doing that. So those two features in here are summarized on this slide.

Basically, the well design features we've already talked about: The four strings cemented to the surface, cement in the injection zone, and caprock that is corrosion resistant, and we've got maximum fresh water at less than 300 feet.

Just to give you an example, the current AGI Number 1, the surface casing goes down to 550 feet. So it's already 250 feet, approximately, below the fresh water there.

In the new well, we have the same basic surface casing, and then we have these additional strings of casing that I already talked about.

We also have an injection zone that's more than 8,300 feet below the base of any fresh water. And we have an excellent caprock above -- almost 3,000 feet of caprock above the Lower Bone Springs, with another underpressured zone, the Brushy Basin, immediately above it.

And then above that, we have production zones, about 2,000 feet of zones that are productive out there, some of which are sour, some of which are sweet.

Then above that, we have 1,000 feet of salt in the Castillo Formation and the Salado Formation, and then we have the Dockum Red Group.

Q. Your next slide identifies the location of the fresh water wells that you were able to find?

A. These are the ones that are listed in the State Engineer's office. And then Mr. Smith's well is -- the well that he has brought up in this location is located right in this location, approximately here.

These are different types of fresh water wells. Some are domestic wells, some are production wells, some are irrigation wells. But those are the ones that were identified from the State Engineer's records.

Q. Just for the Commissioners' benefit, Tab 14 of Exhibit 4 is a table identifying the location and the details on those wells; is that right?

A. That's right. From here, you can see that the maximum well depth of any of these wells is about 200. I think the deepest one is this Markwest Pinnacle well, which is about 270 feet.

In fact, most people that drill water wells out there, they really don't want to go too far into the Dockum Group, because the quality of water in the Dockum Group is far worse than the quality of water in both the Alluvium and the Ogallala. We can see that in the results of water analyses out there.

When you look at just the general water quality in the area, what you see is that the Dockum Group has pretty elevated sulfates and chlorides relative to the Ogallala and the Alluvium that you see out there.

Q. Have you provided some water samples from the area within one mile to the Division?

A. We included those in the original C-108. And then we also -- as a result of the conversation I had with Mr. Jones about -- basically, I think it was last week, on Wednesday or Thursday, I agreed that -- I told him we can get some more recent samples. We got those on Friday and Monday and transmitted the results when we got them on Tuesday.

Q. Exhibit 7, which I have here, is the result of those analyses?

MR. RANKIN: Madam Chair, may I approach?

CHAIRMAN BAILEY: Yes.

Q. (By Mr. Rankin) Mr. Gutierrez, have you anything to point out on these samples?

A. I guess just to point out that these are samples from two wells. Actually, if we could put up that slide that has the map of the wells in the area?

Q. Twenty-three?

A. Right. Just for reference, these two

wells -- one is located right here, and one is located right here, east of the AGI well. Both within --

CHAIRMAN BAILEY: For the record, could you be a little more specific? Because she has difficulties knowing where "right here" is.

THE WITNESS: I'm sorry. Yes.

One well is located approximately three-quarters of a mile east, directly east of the Linam AGI Number 1. And one well is located approximately two-thirds of a mile south of the AGI Number 1 and slightly west, located near the Hobbs plant for DCP there.

These two wells are both pretty much representative of the kind of water that we see in general in the area. One of them has much higher sulfates than the other well does. One has sulfates that are running around 60 parts per million, the other one is about 213 parts per million, both of which are normal.

We have some quite elevated -- basically, if you look at the published literature in the area where we got the original samples that were in the C-108, and the USGS has done some studies out there, as has the Bureau of Mines, the range of sulfates is -- for example, in the Ogallala, probably about 30 to 60 parts per million sulfate; in the Alluvium, probably about a similar range, maybe slightly less.

However, in the Dockum Group, those range from 100 parts per million to as much as 6,800 parts per million throughout Lea County. We also have higher chlorides in that Dockum Group. It's just generally harder water.

Q. Mr. Gutierrez, based on your original analysis of the area and your engineering data and the geology, have you determined that there are no apparent faults or geologic conduits that would act as a conduit for the injected acid gas?

A. Yes.

Q. And that's based on your seismic survey and other analyses?

A. It's based on all of the geologic data out there, seismic, the well logs, the correlations and the cross-sections that we've done out there.

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

A. No, neither the proposed injection nor the injection that we've been doing to date.

Q. In your opinion, will the granting of DCP's application further the protection of human health and the environment?

A. Yes, because it will reduce the likelihood of flaring events both at the Linam gas processing plant and all of the wells that are upstream from those.

Q. Mr. Gutierrez, would the granting of DCP's application require any changes or modifications to the approved H2S contigency plan?

A. Yes, it will. Because when the well is moved, when there is another well added, that will slightly shift the ROE for that H2S contigency plan, depending on where the final exact location of that well is.

Q. Can you define ROE?

A. I'm sorry. The Radius of Exposures at the hundred and 500 ppm level.

Q. The amendment of the contigency plan is something that would be done between DCP and the Environmental Bureau of the Division; is that correct?

A. It's done pursuant to Rule 11. There is an approved Rule 11 plan currently for the AGI facility as it exists. We will modify that plan and have it approved prior to initiating injection in the new well.

Q. And that's nothing that the Commission needs to address at this hearing; is that correct?

A. That's correct.

Q. Mr. Gutierrez, can you please summarize from Slide 26 the environmental and operational benefits?

A. Right. To really bring the whole thing together, I think the addition of another point of injection into that reservoir significantly enhances protection of the public by assuring a greater consistency in the ability to inject acid gas and to switch live from a well that may require maintenance to another injection point without causing the plant to be shut down and all of these upstream wells to be shut in.

The improved design of this particular well and the downhole monitoring of pressure and temperature is going to give us a lot of additional data on that reservoir which will be useful not only for this well, but just for a better understanding of how these wells behave for use in future applications and in the future understanding of how the well will behave.

The Linam AGI Number 2, as I mentioned, will provide additional reliability and uptime. And the H2S is being returned to the geologic reservoir where it came from, as is the CO2, and no additional wastes are being generated.

And again, the CO2 which was being released when we had a Sulfur Reduction Unit or when these flaring events occurred or whatever was being sequestered, it's a greenhouse gas that's being sequestered.

Q. In your opinion -- let me back up real quick.

Can you also quickly summarize what it is that DCP is requesting of this application?

A. Sure. Basically, as you know from the C-108, we're basically requesting the ability to have another well that will serve as a redundant or backup. And that will allow us to inject while we are doing maintenance on these wells, or it will allow us to cycle from using one well to another and back and forth. That will allow both wells to be on kind of a preventative maintenance schedule and inspection that will allow for a better overall operation.

And of course, it will allow us to work over the Linam AGI Number 1 without having to shut in producers.

Q. In your opinion, will the granting of this application result in waste or impair any correlative rights?

A. No, not at all.

Q. Were Exhibits 1 through 7 prepared by you or compiled under your supervision --

A. Yes.

Q. -- or do they represent business records of Geolex and/or DCP?

A. Yes, sir.

MR. RANKIN: Madam Chair, I'd like to

tender for admission Exhibits 1 through 7, with the exception of Slide Number 25 from Exhibit Number 3, which we did not offer.

CHAIRMAN BAILEY: Any objections?

MR. ALVIDREZ: No objection.

MR. RANKIN: One additional comment. We did not offer Exhibit 6, which was a DVD of the cement bond logs. So we won't offer Number 6 for admission.

CHAIRMAN BAILEY: Did you have any objections?

MR. ALVIDREZ: No objection.

MS. GERHOLT: No objection.

MR. RANKIN: Madam Chair, I pass the witness.

CHAIRMAN BAILEY: The exhibits, as you've described them, are accepted.

Do you have any cross-examination, Ms. Gerholt?

(DCP Exhibits 1 through 5 and Exhibit 7 were admitted.)

MS. GERHOLT: I do, Madam Chair.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. Mr. Gutierrez, in layman's terms, would you please explain what's happening in a reservoir when a well goes on a vacuum? You talked about when you were completing the workover for the AGI Number 1, it went on a vacuum. I'm just trying to understand what that means and what that means for the reservoir.

A. Sure. What it means is that the reservoir -- going on a vacuum means that it's taking fluid without having to have any pressure applied to it. In other words, it means that that reservoir is underpressured relative to the zones around it and that it will take fluid at a lower pressure.

What it means is that it is a reservoir that is transmissive and that is not reaching its capacity in terms of what it can hold.

Q. If something is not being injected into that reservoir, does anything change within that reservoir?

A. What it means is that whatever fluid that is in that reservoir is not likely to be migrating anywhere. Because it is essentially underpressured, there's no force to make it move away.

Q. Again, in regards to the workover of the AGI Number 1, after sending the tubing to the metallurgic company, it was determined that there was pitting inside the tube. Was that pitting caused by the free water in the tubing?

A. It was caused by the free water mixing with the acid gas that we were injecting in the tubing, yes.

Q. And you're of the opinion that managing the temperature will stop that free water from coming out; is that correct?

A. Yes. And in fact, that's what we've observed in the operation of the well since we got that temperature under control. Because we just did an MIT on November 14th, after almost the entire year of operating under those conditions, and it passed without any problem. So we don't have any additional corrosion.

Q. What is that current temperature range?

A. Roughly about 120 degrees. It varies from 115 to maybe 125, in that range. But it's roughly about 120, 121 degrees.

Q. So at the most, a range of between 5 degrees you're seeing, more or less?

A. Well, it is -- under a normal operating system, when you stop injecting, the temperature of the acid gas that's in the well itself, you know, does tend to start equalizing somewhat. But the reservoir temperature is about 130 degrees anyway.

So the variation that we see in that temperature, I'd say, is plus or minus 5 degrees, yes, somewhere in that range. About a 10-degree variation, from about 115 to 125.

Q. You mentioned that in December of last year, DCP discovered that there was an issue when they went to conduct the MIT and that you reviewed the data that was collected on this real time injecting; is that correct?

A. Yes, that's correct.

Q. Was this data also provided to the Oil Conservation Division?

A. It was, in December, along with that December 19th letter.

Q. I'm not certain if you're the right person to direct this to. So if you're not, please let me know who is.

You mentioned in drilling -- if the Commission were to permit a second AGI well, that in the drilling of this second well, you would place an additional intermediate string that would be placed further down than in the current AGI Number 1; is that correct?

A. That's correct.

Q. Can you explain the safety procedures that will be in place during the drilling of the second well, because you will encounter an acid gas plume?

A. Sure. First of all, we will have -- just like we did during the workover, we will have a safety company, like Total Safety -- I don't know if it will be Total Safety, but somebody like that -- that will have developed -- and we will have developed a specific H2S contigency plan for the drilling of the well. That's a different thing than the H2S contigency plan associated with the operation of a normal injection well.

For any -- you're required, under New Mexico rules, to develop an H2S contigency plan any time you think you might encounter H2S when you're drilling a well. So here we don't only think we will encounter it, we probably will probably encounter it. We may not. It may not have extended as far away as where we put this additional well.

It's right on the edge of where I calculated is the extent of the acid gas that we have in the reservoir right now. So we may or may not encounter it, but we want to ready for it. So we'll have an H2S contigency plan that deals with that.

One of the big advantages is that we're drilling so close to the existing well that we don't anticipate any significant differences in the geology between the two, so we know at exactly what depth we're going to hit the top of the injection zone. So we're going to stop before we get there, and we're going to set this casing.

And the main reason for that, if I were drilling this well and we had not already been injecting acid gas, I would have not recommended this deeper casing. But the problem is that we've got -- it's not a problem; frankly, it's an advantage to us -- is that we have this lost-circulation zone above the caprock.

If we were drilling the well like we drilled the AGI Number 1, my fear is that I would not be able to maintain enough mud weight in the hole to be able to control the injection zone while I'm setting the production casing, and I have 5,000 feet of open hole between the intermediate casing and the injection zone.

So for that reason, I'm extending and drilling a larger-diameter hole deeper, to just above the injection zone. I will set casing and cement that. And that means that I will only have a very small open hole when I penetrate that injection zone.

Q. Mr. Gutierrez, if I can draw your attention to DCP Exhibit 4, the C-108 application, specifically to page 3. The bottom says, "page 3." It's not actually the third page within the application.

If I can draw your attention to the third paragraph from the bottom, it begins, "In addition to providing a safe and adequate reservoir." Do you see that sentence?

A. Yes.

Q. Just for clarification of the record, DCP is here today only on a Class 2 disposal well; is that correct?

A. Yes.

Q. They are not seeking a Class 6 authority?

A. Absolutely not.

MS. GERHOLT: Those were my only questions. Thank you, Madam Chair.

CHAIRMAN BAILEY: Mr. Alvidrez, do you have any?

MR. ALVIDREZ: Yes, Madam Chair.

Good morning, Mr. Gutierrez.

THE WITNESS: Good morning.

CROSS-EXAMINATION

BY MR. ALVIDREZ:

Q. If I could have you flip to Slide 18 of your presentation? And I believe you testified earlier that this is sort of a graphic depiction of the existing AGI Number 1 well?

A. Yes, sir.

Q. This is the AGI well that you described earlier as having, I guess, suffered a failure or having a leak; is that correct?

A. The tubing within the well leaked, yes, sir.

Q. In reference to the graphic depiction, when you say, "the tubing had a leak," can you show us where the leak area was?

A. Yes, sir, I can. It was right here, immediately above the packer, and right here on the wall of this tubing.

As a matter of fact, it wasn't even all the way around the tubing, but it seemed to be almost in a line of pinholes and then holes that ranged up to about this size in the tubing -- "this size" being about an inch and a half or so in diameter -- and they were restricted to the bottom 60 feet of the tubing, right here.

Q. So there were 60 feet of area where the integrity of the tubing had been compromised?

A. Yes. As I mentioned, the bottom most joint, the 20 feet, is the one that had the most holes that actually penetrated the tubing. But the next 42 joints also had pitting and corrosion and some pinholes -- small holes in them.

Q. Just so we can kind of tell what the schematic is, or so I can, you've got the center tubing here. You've identified where the perforations were?

A. Yes, sir.

Q. And then you've got these little boxes depicted. Are those packer -- or is that the packer?

A. This X here, that is the packer, yes, sir.

Q. What does that do? What function does that serve?

A. To put it simply, it's like if you remember in chemistry, where you put a rubber stopper, and you put a piece of glass in a flask. That rubber stopper is what prevents the material that you're injecting through the tubing into the perforated interval, the well, from coming back at you. It's essentially like a stopper.

Q. From your earlier testimony, I understood that there was a plan to put another packer in, and that plan didn't work out so well. Where was the second packer going to be put in?

A. Immediately above the original packer. So essentially what we would do if -- I don't know if -- I could draw it on that board for you.

But basically what it was going to do was have -- the existing packer would be sitting there, and we would have -- if you notice, the existing packer has tubing that extends below it. This is not actually part of this same tubing. It's what's called a seal assembly, and it's permanently in the packer.

So what we were going to do is take another packer that would also have a seal assembly, stab the seal assembly into the existing packer, and then have another packer right above it. So basically, there would be a continual tubing going through both packers and into this zone.

And the other packer was going to be set at 8,600 feet. This one is set at 8,650.

Q. The plan, when this AGI Number 1 well is re-worked, is to attempt to re-insert that packer?

A. We will get a packer in there. The problem that occurred is we actually had -- my own opinion is that we had a failure.

These packers are set up so that you basically slide them in the well, and then you set them hydraulically. I don't need to go into all the details. I'm not sure that I even understand exactly how these things work. But the bottom line is they're set hydraulically.

But when you're sliding the packer down the hole, if it encounters an area where the casing might be slightly out of round or where there is a little constriction or bend in the casing, then what can happen is it's almost like you get it; it gets stuck. And then as you try to move it further down or up, it shears off these -- what are called setting pins, and it allows these grippers, if you will, to grip the casing. And then the packer is -- and then it's there, and it's not going anywhere.

Q. And that's what happened?

A. That's what happened here, and it happened at about 800 feet. So obviously, we were not going to set a packer at 800 feet, so we had to mill it out of this well.

Q. This second packer that you recommended is for reliability and safety purposes; correct?

A. In order to -- as I mentioned, while this tubing had holes in it, there is casing opposite that tubing above the packer. That casing did not have any holes in it, but the casing integrity log showed that it did experience some corrosion.

So what we want to do is isolate that so that we don't have a chance, if any acid gas were ever to escape into that annulus again, to attack that piece of casing that's already had some corrosion. Because the casing that is below here, by the way -- I mean anything that's below the packer you can expect a lot of corrosion in, because that's just how these wells work. But what we don't want is for that to occur above the packer.

Q. Your analysis and the analysis that the metallurgist did indicated that you were getting corrosive effects from both the inside and the outside of the tubing?

A. We had initially free water in the tubing. It caused some communication with the annular space here.

And then once you added acid gas in this annulus, it was working at it from both sides, so to speak.

Q. Once it started leaking, the water got outside, into the annular space. And that just sort of accelerated the corrosive activity; is that --

A. That's basically it. Yes, sir.

Q. And as I understand it, in terms of how the water got in there, it was due to a failure to control the temperature within a close enough range to keep water from forming?

A. Yes. When you compress acid gas prior to putting it in the hole, you do it in five stages. And at each one of those stages, the free water is dropped out and taken out of that acid gas.

Now, once it goes in the last stage, you have this gas compressed to what we call a supercritical phase. What that means is it's in a phase envelope, which is a pressure/temperature envelope, that gas is in that makes it behave -- even though it's still a gas, it's a dense phase and it behaves like a liquid.

If you have fluctuations where that gas can get out of that phase envelope, you can have some very small amount of water that is still left in that gas that essentially condenses out. And that's called free water, and that's what caused the corrosion.

Q. I guess is the combination of the water and the acid gas a very corrosive substance?

A. Yes.

Q. As I understand it on the new well, the proposed well, AGI Number 2, you're using some type of treated or conditioned tubing, at least in a portion of it, that is resistant to corrosion?

A. Yes. It's not -- I think it's not necessary with respect to the -- with the current ability to control the temperature better. In fact, we don't use it in a lot of other AGI wells. But it basically provides for additional safety in terms of the tolerance of that material to handle some occasional corrosive condition.

Q. As I understand it, when this AGI Number 1 was re-worked in April of this year, all 8,000-plus feet of the tubing was pulled out; is that correct?

A. That's correct.

Q. Was entirely new tubing installed, or did you put the old tubing --

A. We installed 8,650 feet of brand new tubing.

Q. I take it the new tubing that was installed doesn't have this corrosion inhibitor that you're planning for the new one?

A. It is the same type of tubing that we had in there before. It's L-80 tubing.

Q. It doesn't have the corrosion inhibitor protection that you talked about with respect to the proposed design on the second well?

A. That's correct.

Q. In terms of -- you've identified an issue in terms of temperature variation and the formation of water.

You would agree, would you not, that it would be prudent to have an operational parameter with respect to this well, where you would operate within an acceptable range, temperature range, to avoid the formation of water in the tube, would you not?

A. Yes. And as a matter of fact, that was my recommendation to DCP and, in fact, what we they implemented and have been continuing to do.

Q. You would recommend that the Commission, as part of its oversight in ensuring safety, health and the environment, would impose an operational parameter or requirement that operations be maintained within that acceptable range, would you not?

A. I wouldn't see a problem with that, except that one of the things that we have to recognize is that, you know, in a situation where you have a startup condition or a -- when you have to cease injection and then start again, it will take some time to get that reestablished. But yes, I think the goal is to operate that within a specific temperature range.

Now, it's important to remember it's not just temperature, but it's a pressure/temperature relationship. So as long as you have a combination of those two factors that allows you to stay in that phase envelope, you won't develop any free water.

But the bottom line is yes, I think you can operate -- if you can operate it within that temperature range, it is significantly helpful.

Q. In terms of operational parameters -- let me step back.

You talked about depending on the pressure, one temperature, I guess, would be less conducive to water formation. Is there an inverse relationship? The higher the pressure, the lower the temperature?

A. It's a complicated phase diagram. But basically you can raise the pressure and lower the temperature and you still will be within the phase envelope, or you can raise the temperature and slightly lower the pressure and still be in that same phase envelope.

But in effect, when you are controlling all of those program parameters, the real key is establishing a differential pressure between what you observe in the annular space and the tubing. And as long as you keep that temperature constant, maintaining that differential and knowing that operating range, that's the most effective way of controlling this, rather than strictly a temperature control.

Q. How are those operating conditions monitored? Let me ask it with respect to the AGI Number 1 well.

A. Sure. There are sensors that are placed immediately at the wellhead. So above the well tree and in the tubing that leads from the compressor to the wellhead, there are monitors in those lines. And they monitor pressure, so you know your injection pressure. We have to monitor that because we know we can't exceed the maximum operating pressure.

And those are connected electronically to what's called the Scadar PLC system at the plant, so those are taking readings. Every like tenth of a second, I think they're taking readings. So they're reading continuously the injection pressure.

The injection temperature, the annular pressure that is in the space between the tubing and the casing, right in here, that's being monitored at the wellhead. And those are being fed back to the plant, and they're also recorded. That data is stored electronically.

Right now I get essentially an electronic dump of that data every month for the previous month, and that's what I use to prepare my report to the OCD that gives the graphs and the actual monitoring conditions. And I reduce it to only providing hourly data, just because otherwise, it would be huge.

Q. Do you provide that in electronic format or a written report?

A. Both.

Q. In terms of the operational parameters you talked about, controlling pressure and temperature, is that something -- a report or some analysis that you've prepared and provided to DCP for their operations?

A. I'm sorry, I don't understand that.

Q. I understood that you talked to DCP and said, "The cause was because of a great temperature variation. You need to maintain operations within a given parameter so that we don't have this water produced"?

A. Yes.

Q. I'm asking, did you have a written report or something like that that you gave to them?

A. No, I didn't. I communicated that verbally and in several meetings where we went over the metallurgical results and the metallurgical analyses that we got.

And I used basically the C-103s and the graphs that we prepared along with those reports to the agency, to frame that discussion with DCP. I said, "See how we maintain this pressure here? See, when it gets out of this range, we have a change in the annular pressure?" So I did it basically that way, verbally.

Q. How is DCP able to confirm that it's operating within the parameters that you suggested for them?

A. They're -- like I said, they've got real time monitoring continuously. So they've set -- and maybe you can ask Mr. Boatenhamer specifically. But I know that they've got alarms set up so it allows them to see if they're in the band, so to speak.

Q. Are you able to tell the Commission today what the parameters are? Is that something that you can talk about, an upper end of the pressure versus temperature?

A. Sure. I think if we looked at one of the C-103 reports that shows that for the monthly, you could track it. But generally, I think it's, as I answered Ms. Gerholt's question, that the temperature band was roughly between 115 degrees and 125 degrees.

Q. That would be more of an optimum temperature band?

A. Yes. It's not so much that the temperature was out of that band at any one point in time.

It was more that when they were operating the well initially, there was very poor control on that temperature because of the problems with the control systems that I described, and it was ranging very dramatically.

It's really the huge fluctuations that caused the problem, rather than -- I mean you could have accomplished the same thing by staying in a lower temperature band with a higher pressure, but as long as you didn't fluctuate very dramatically there.

Q. One of the parameters that you want to build into an operational requirement would be not allowing the temperatures to fluctuate outside a given band?

A. Right, right.

Q. What would that fluctuation amount be?

A. Like I said, I think ideally it would be probably between 115 and 120 degrees, the temperature. But I wouldn't see a problem with necessarily going down to like 100 degrees and then going back up. I would not want to be seeing anything certainly lower than 100 degrees.

Q. In terms of when you -- you talked about -- I think you suspected there was emulsified diesel. And I understand that to mean that there's water in the diesel, and it becomes kind of a congealed substance down there.

Is that something that you actually saw when the tubing was pulled up?

A. Yeah, we did. I couldn't tell you exactly -- obviously, when it came out, we had emulsified it ourselves because we killed the well with brine. So I couldn't tell you that what I saw was specifically what was sitting down there at the bottom of the hole.

But what I did to determine that was basically I went to what the standard was for the diesel that we purchased, which is a normal diesel standard. And what I found is that the allowable amount -- now, I don't know if that's how much water was in the diesel or not.

But I mean the allowable amount for diesel to pass standard would result -- when you put 8,600 feet of diesel in that column, would result in about the equivalent of about a foot of free water, if you were able to take all the water out of the diesel, so to speak.

So my hypothesis is that what happened after the diesel sat essentially immobile in that annular space over an extended period of time, whatever water could separate out of that diesel, if any, would have settled at the bottom, above the packer. Because of course, that diesel can't go out of this closed system, so it would have settled down there.

And the emulsified diesel down there, once we had acid gas in that annulus, then that acid gas takes advantage of whatever water is down there to make a more corrosive situation.

So what we've done -- another thing that we did when we put the new diesel back in was to add further corrosion inhibitors. And we got as good a diesel as was available, and we added corrosion inhibitors and biocides, too.

Q. The biocides are to control, I guess, the formation of any biological material, bacteria?

A. Yeah, because bacteria can cause corrosion also. We didn't see any evidence of bacterial corrosion when we got the metallurgical results because we didn't have the metallurgical results when we were putting the well back together yet.

Q. So I'm clear, is my understanding correct that there are really two potential sources of water with respect to this? There's the source of water or some sort of water condensate that forms on the inside of the tubing, and then there is also the water that would be in the diesel, in the annular space? Is that -- is my understanding correct about that?

A. Those are the two potential sources. However, the water that would be the emulsified diesel, if you will, in that annular space, as long as it's not exposed to any acid gas, it really doesn't have much of a corrosive effect.

Q. As I understand it, the Linam AGI Number 1 went into operation in 2009?

A. In December 2009, roughly, yes, sir.

Q. And so I guess roughly two years after initial operation, we had this problem here with the leaking as a result of the corrosion; correct?

A. We had a tubing leak, yes, that had manifested itself.

Q. Were you able to determine how long that leak had persisted?

A. Not really. And that's why I had mentioned that when -- it wasn't until the attempt to bleed diesel to lower the pressure on the back side from the MIT, until we did that, there really was no indication that we had a problem there, and in part, it is because, as I mentioned earlier, these wide fluctuations of temperature caused some significant fluctuations on the back side of that well in terms of pressure, and it was just difficult to determine whether we really had a potential problem there or not.

Q. As I understand it, the original schedule for the integrity test, the MIT, was every five years?

A. That's correct.

Q. And you saw a problem manifest itself well sooner than the five years?

A. Yes, sir, we did.

Q. So in terms of the increment of time, as I understand it, DCP is willing to agree to do the testing at least once a year?

A. Yes. And as a matter of fact, in the working group that we've had that's developed the draft regulations that we will propose to this Commission, that group decided it would be appropriate for AGIs in general, all AGIs, to require an annual MIT test.

Q. Now, you indicated, when you were originally going to -- I guess when you originally proposed a second well, the Linam AGI Number 2, that there was a location that you suggested. But then I guess, in consultation with representatives from DCP, they wanted it moved to a different location than the present location where they're proposing to drill.

As I understand it, that was because they wanted it downwind? They wanted the new location downwind of the existing well?

A. No, not downwind. They wanted a situation where -- the way I had positioned these two wells, the Linam AGI Number 2 would be located almost directly downwind of the Linam AGI Number 1, given the prevailing winds out there. Of course, you can have wind going in any direction at different times.

So what they said is it would be a lot better if we had it to the south, where neither one of them is in the direct path of the prevailing winds.

Q. That's because H2S is a very toxic gas?

A. Yes. It's because you want to avoid, to whatever extent possible, putting anybody in a position where they might be downwind, yes, sir.

Q. So it's a legitimate concern if you're downwind of a potential source of H2S gas?

A. It's a legitimate concern. That's why there is a Rule 11 H2S contigency plan and why there are all the safety factors, including these monitors all around the wellhead and at the boundaries of the AGI facilities.

Q. When the Linam AGI Number 1 well was re-worked back in April, were you on site?

A. Yes, sir. I was on site for three weeks.

Q. And as I understand it, there was actually a situation where a bubble of the gas escaped during the re-work?

A. As I described in my testimony earlier, what happened is we were set up to displace all of that diesel. Once we pulled the tubing -- killed the well and then we pulled the tubing, we had to displace the diesel in the well. Actually, I'm sorry, I got the steps backward.

We displaced the diesel before we pulled the tubing. So we wanted to get all the diesel and all of the potential acid gas that had leaked into that annular space out of that annular space before we pulled the tubing.

So we killed the well, put a blanking plug in. And then we started circulating the diesel which fills up all of this annular space above the -- so we started pushing brine here, pushing diesel down and u-tubing it back up. And the diesel that was coming back up -- this was all contained. It was all within piping, of course.

And then the diesel would be put into a separator, a portable separator, that would separate the diesel from the acid gas, route the diesel to some holding tanks, and route the acid gas to a portable flare and flare the acid gas. And that portable flare is what went out.

Q. And I guess it was overrun by the gas, the CO2 and the gas and what have you?

A. That's right. Basically, the CO2 in that TAG bubble blew out the flame, if you will.

Q. And as a result, there was a leak into the atmosphere of H2S and CO2; correct?

A. That's correct.

Q. And it was sufficient that it triggered the monitoring at the well and the fence line monitors; correct?

A. It triggered the monitoring that was set up portably by Total Safety around the well, and it triggered the monitors right at the well, and it triggered one monitor at the fence line, yes, sir, on the northeast side.

Q. While you were working on this well, did you have -- did you utilize the personal H2S monitors?

A. Yes.

Q. What are they for?

A. Anybody that works in a sour gas plant has a personal monitor. Typically, they carry it on their hard hat or in their pocket. I had one when I was out there.

And what it does is it alarms at 10 ppm and at 15 ppm. It's basically to provide you with an early warning that hey, there's a problem, and you better get out of the way.

Q. And in your experience, are these monitors fairly reliable?

A. My experience is they are, yes, sir. They're set far below the OSHA standard. For example, the OSHA standard is that you can be exposed to up to 80 ppm of H2S for eight hours. So these things are set at 10 ppm and 15, so they give you plenty of warning.

CHAIRMAN BAILEY: Mr. Alvidrez, do you have many more questions?

MR. ALVIDREZ: I'm guessing I'll probably have about 30 minutes.

CHAIRMAN BAILEY: Why don't we take a lunch break now and then return at 1:00 for your continued cross-examination? We will reconvene at 1:00.

(A recess was taken.)

CHAIRMAN BAILEY: We're back in session now.

Mr. Alvidrez, you were in the process of cross-examining Mr. Gutierrez.

MR. ALVIDREZ: Thank you.

Good afternoon, Mr. Gutierrez.

THE WITNESS: Good afternoon.

Q. (By Mr. Alvidrez) If we could go back to Slide 18 of your presentation with respect to the leak that occurred on the Linam AGI Number 1 well, I take it that the acid gas escaped into the annular space. Is that a correct assumption?

A. Yes, sir.

Q. In this area here, or on the other side?

A. It would be in that area right there, between the tubing and the production casing.

Q. And I guess from there, it formed a bubble in the diesel?

A. I don't know if a bubble is a good analogy, but it was a -- there was some -- like for example, what probably occurred when the well was still operating is that we had had some acid gas that had accumulated in this area right here. As we circulated it out, that acid gas basically traveled up the annular space. Yes, sir.

Q. And the acid gas is in a gaseous state; correct?

A. It was probably in a -- it was probably somewhere not in a complete dense phase, but not necessarily completely a gaseous phase, either. But it would get into a gaseous phase as it traveled up the wellbore.

Q. As it traveled toward the surface, it would become gaseous?

A. Yes, sir.

Q. And it would naturally migrate upwards, I take it?

A. No. Actually, it was denser than the diesel, so that's why it stayed at the bottom. That's why we had to circulate it out. It would not just go up on its own.

Q. Now, if I understood your testimony earlier today, the first time at which you became aware of a leak on the Linam AGI Number 1 well was when you were notified in December about the problems with the integrity testing. Is that a correct understanding?

A. No. That's when I first became aware that there could be a problem. I could not confirm that there was a leak either in the tubing or the packing until we actually did the workover itself.

Q. So it wasn't really until April, when you pulled the tubing up and saw there was holes in it?

A. That's right. We -- well, no. I'm sorry, that's not correct.

When we attempted to do the MIT and could not bleed the pressure off, that was some indication to me that there was communication between the tubing and the annular space.

At that point, I didn't know, though, whether that communication would be as a result of a tubing leak or possibly a packer seal leak.

Q. But it did suggest to you that there was a failure in the integrity of the well in some location?

A. Of the internal components of the well, yes, sir.

Q. I think you said you were given a lot of data and spent a weekend poring over it. Can you tell us what data you reviewed?

A. Sure. Injection pressure over time, injection temperature over time, annular pressure over time, and injection rate.

Q. And what conclusions did you draw, based on that data?

A. Well, based on those data, I could not determine -- because of the temperature fluctuations and the resultant fluctuations of pressure on the back side, it was not possible to determine exactly when that behavior might have been indicative of the initiation of a potential problem.

But when we had bled diesel from the back side and we didn't see a drop in the pressure on the back side, that was, in my mind, diagnostic that we definitely had some potential communication in there.

Q. Can you explain for me what you mean by, "the back side pressure drop," and that sort of thing --

A. Yes.

Q. -- some idea how it works?

A. The way you really monitor these wells is to look at the differential between the tubing pressure -- that's the injection pressure that you're causing when you're compressing the gas and putting it in under pressure.

The back side of the tubing is what we call the annular space. I call it the back side. I may call it different things, but it's the space between this casing and the tubing. That is a completely closed system. And diesel is noncompressible fluid. That's why we put that in there. That allows us to measure the pressure in that zone.

When you start injecting, the tubing actually physically balloons a little bit, plus it heats up, because you're putting hot acid gas down that tubing. That causes the diesel immediately in contact with the tubing on the outside to also heat up. And the swelling, if you will, of the tubing, also pushes against the diesel. And since there's no place for that diesel to go, what you see is an elevated pressure on that back side. And that's what we call when we monitor the back side pressure.

So what you're looking for, really, you know, much more so than -- you know, before lunch we were talking about the temperature fluctuations. And while the temperature, I think, was the root cause of the free water that we had in the tubing that caused the corrosion, the real fundamental way to monitor these wells is to monitor the differential between the tubing pressure and the back side pressure and to understand that that's affected by temperature.

But if you monitor that closely, you can get an indication that you may have a problem. But really what is definitive, and the reason why I think the practice has evolved to require annual MITs, is because an MIT is really what will tell you if you have a problem or not in a well.

So while it's important to have these kind of operational parameters and monitor those, and, in fact, the conditions that the Division has proposed, are to establish what are those normal operating procedures and ranges that you would expect. What it would lead you to do is to say, "Okay, look. Based on what's happening on the back side and the injection pressure, it looks like this doesn't look exactly right to me. We better take some further steps to try and diagnose if we really have a problem or not."

And fundamentally, the real key step that you can't argue with, you can't argue with the results, is an MIT. If the MIT is good, the well is good. If the MIT is bad, you've got a problem.

So the goal and what we have worked with the Division on other AGIs, not this one, but -- well, this one, as well -- but I mean is to formally go through some discussions to identify what those normal operating parameters are and provide for if you step outside those operating parameters, to call the Division and say, "Okay, here's the data that we've got. Let's take a look at this data and determine if we need to do an unscheduled MIT to confirm whether we have a problem or not."

For example, this happened just recently, about six months ago, with Targa, with their injection well. There was some odd behavior on the back side of that well, and they didn't know whether there was a problem or not. They met with OCD. They got us involved, and we went out there and did an MIT. And we confirmed that indeed, there wasn't a problem, but we better understood what was causing some of those fluctuations. So really, the MIT is the definitive diagnostic tool.

Q. So if I understand, the MIT will help conclusively either rule in or rule out whether you've got an integrity problem.

But weren't there indications, just based on the data that you were gathering, between the pressure differentials in these areas that we talked about, that there was a problem with this well for quite some time?

A. In hindsight, after we could not reduce the pressure on the back side, when you looked at the data, there is indications that you might have had a problem. But frankly, you couldn't really discern that from those data alone because of the temperature fluctuations that you were seeing.

Q. How do you control the temperature in terms of the gas injection?

A. That would probably be a better question to ask Mr. Boatenhamer from an operational perspective.

But fundamentally, they have coolers that are set up with a louvered type of system that actually controls that temperature. But he would be a better person to answer that.

Q. Are you aware of the current plans or timeline for installing the second packer you discussed as recommended?

A. Yes. We are -- the intent is to drill the AGI Number 2, complete the AGI Number 2, and to -- once we begin injecting into that, to then go back and work over the AGI Number 1. And in the interim, we are providing that monthly data to the OCD and doing MIT tests every six months on the AGI Number 1.

Q. Now, you talked about, I guess, when the AGI Number 1 was initially installed, I think you said you had examined a location at the actual Linam gas plant or very close to it. But that wasn't a suitable location, so the actual well location was moved out some distance from the plant.

And I think what I'm trying to get an idea of, was one of the reasons why the location or a location near the gas plant wasn't ideal was because of faults in the geologic formation in the vicinity of the plant?

A. Not really. The reason is that in the vicinity of the plant, the Lower Bone Springs is absent. I mean it's just flat out not there. Because once you get closer to the plant, you're up on this Central Basin Platform. So it's just missing.

Q. So I take it the Linam AGI Number 1 is operating right now?

A. Yes.

Q. What pressures is it producing?

A. Roughly about 1,450 pounds injection pressure.

Q. Have you recommended to DCP, during this interim period before you got the packer in and finished all of the steps that you want to finish with respect to the AGI, any operational parameters that they should follow for safety purposes?

A. No, none, other than the ones that we've discussed, which is looking at this data every -- on a regular basis, every month, and doing these MITs every six months.

Q. So what are you looking for in this data that you're reviewing each month?

A. I'm looking for a -- maintaining a pressure differential between the injection pressure and the annular pressure, and I'm looking for no anomalous behavior of the annular pressure or no consistent increase.

So I'm basically looking for what I call railroad tracks. In other words, the trend for the injection pressure and the annular pressure, that they're staying consistently separated by a certain pressure differential, and that barring a change in injection rate -- because as the injection rate increases, the injection pressure will increase, and so will the back side pressure. But I'm looking for essentially parallel behavior of those parameters.

Q. What are the data showing to date?

A. Well, since the plant worked out the temperature fluctuation issues, what we see is that indeed, we are maintaining a pressure, injection pressure, roughly in the 12- to 1,500 range, depending on injection rate and temperature, and a back side pressure somewhere in the zero or 50 to -- I'd say, zero to 5-, 600 pounds on the back side, and a pressure differential between the injection pressure and the back side pressure of somewhere in the 7-, 800-pound range. And then, of course, we were confirming that we don't have a problem by doing an MIT every six months.

Q. What's involved in doing the integrity tests?

A. The mechanical integrity test is done as follows: Bleed off any pressure on the back side down to zero. In other words, remove some of the diesel so that the pressure on the back side goes to zero.

The first diagnostic part of the MIT is determining whether or not that pressure bleeds off. It should bleed off immediately, as soon as you start taking diesel out. That's the first behavior you look for.

So if that bleeds off fine immediately, then you pressure it back up by re-introducing diesel into that space to a pressure of 500 pounds. This is standard in terms of the OCD's testing methodology.

Once you've got it at that pressure, you put a chart on it, which is essentially a pressure chart, and you chart it for 30 minutes. And the determination of whether or not the MIT passes is: Does it stay at that pressure that you pressured it up to within 10 percent, plus or minus, for that 30-minute period?

Q. I had asked about the ultimate location for the AGI Number 1 well. And you talked about this was, I guess, the location where you could access the preferred location, which is the Lower Bone Springs, I guess, formation?

A. Yes. In fact, we originally identified two potential formations, one being the Brushy Basin -- Brushy Canyon member of the Glorieta, and then the Lower Bone Springs as a lower zone. Either one would work as an injection zone, but we selected the lower one.

Q. As I understand it, in terms of wells, I think, within a one-mile radius of the AGI Number 1, you've got three wells that penetrate to that location? One is the Linam AGI Number 1; correct?

A. Yes, sir.

Q. And there's also the Conoco -- I guess it's called State Number 1?

A. That's an old plugged and abandoned well, yes, sir.

Q. And the Goodwin Number 3?

A. That's correct. That's also a plugged and abandoned well.

Q. As I understand it -- let me ask you about what you did with respect to that. I suppose if these wells were not -- had never been plugged or abandoned, that they would form a conduit from that formation to the surface, assuming they're not plugged and abandoned?

A. They might. They might not. I mean if they're properly cemented, even if they're not plugged and abandoned, they wouldn't necessarily present a conduit.

Q. What's the history on these? I think you put up a slide previously showing both of the wells, the well configurations. Can we put those up?

MR. RANKIN: Those are Tab 8 and Tab 9 in Exhibit 4, the wellbore schematics.

MR. ALVIDREZ: Right. Tab 8 and 9 in the application; correct?

MR. RANKIN: Yes.

Q. (By Mr. Alvidrez) We've got a schematic here with regard to the Goodwin Number 3. Is this something that you prepared?

A. From the records available that OCD has, yes.

Q. So what you did is you looked at the OCD records and then came up with a schematic depicting some history and, I guess, the anticipated current configuration of the well; is that correct?

A. That's correct.

Q. And you did the same thing for the Conoco State Number 1 well?

A. That's correct.

Q. So I take it that there's -- other than reviewing the records, you haven't done anything else to assess the integrity of either of these wells; is that correct?

A. That's correct. But I think it's important to notice that on the Goodwin Number 3, for example, this well did not even really penetrate the injection zone. It was drilled to a total depth of 8,582 feet. We presented it as having penetrated the injection zone because it was close enough that we thought we should present that data.

But it was plugged back to a depth of 7,920 feet, which is a good 700 feet above our injection zone. And that's when they attempted to make a producer out of this well. And when they couldn't, they went ahead and abandoned the well and then plugged it, as you see on this diagram. This one actually never really even penetrated the injection zone. It's above it. But it did penetrate the caprock.

Q. It's into the formation? You've identified it as being in the same formation as the AGI Number 1 well; correct?

A. The total depth of it is in the upper portion of the Lower Bone Springs. That's our caprock. It's not in the injection zone. Our injection zone starts at 8,700 feet.

Q. With regard to Goodwin Number 3, can I have you take a look at what is Figure 8 in the DCP application?

A. Yes, sir.

Q. So am I correct that this map actually depicts the location of Goodwin Number 3, as well as Conoco State 1 that we talked about?

A. Yes, sir.

Q. And the Goodwin Number 3 is -- I've got a color copy. But it's located very close to, I guess, the highway that's depicted on the map, the broken line -- State Road, I should say, GG30. Maybe that's not the highway.

A. No. This is a dirt road. But this is where the Goodwin Number 3 is located, right here.

Q. I take it you haven't been out to the location of the Goodwin Number 3?

A. Not recently, no.

Q. Do you know on whose land the Goodwin Number 3 is located?

A. I believe it's on Mr. Smith's land.

Q. And it's --

A. It's right up here.

Q. And I think you testified earlier, I guess, that you've looked at some of the water sampling that's been done at one of the wells on Mr. Smith's property?

A. Yes, sir.

Q. And I think you identified that water sample as having come from a well in that general vicinity?

A. My understanding is it is a well that is located at the trailer house that is -- and the barn facility that's located here, at the end of this road.

Q. And the Goodwin Number 3 is in the vicinity, I guess?

A. It looks like it's within a few hundred feet away. Yes, sir.

Q. Now, have you ever recommended to DCP that they go and do any testing on Mr. Smith's water?

A. No.

Q. Or do any other type of testing about whether there are any possible excursions of H2S on his property?

A. No, sir.

Q. You're aware that he has come before this Commission previously and testified that he's got problems with H2S on his property; right?

A. That's correct, I am.

Q. So part of your analysis with respect to the present application was not to do water sampling on Mr. Smith's property?

A. That's correct. I don't think it's necessary.

Q. What was the initial test that was done in 2008 to assess the integrity of this formation?

A. We did several things. We did a detailed geophysical logging of the formation, using a formation microimaging log that would determine if there were fractures or faults in the formation.

We cored numerous locations within the injection zone and the caprock and did detailed analyses of those cores for permeability and porosity.

We looked at the geophysical logs for the entire geologic section out there and identified the thickness and integrity of the caprock from looking at those logs.

And we did a long-term injection test of the reservoir, a five-day injection falloff test, and we also did a step rate test that looked at the analyses for recently.

Q. What is a step rate test?

A. That's a type of injection test. It's a routine injection test that is performed to evaluate the ability of a formation to accept fluid and at what point that formation would pass what is called its parting pressure or its fracture pressure, to determine what is a safe pressure to be able to inject into the formation.

Q. Now, would it be feasible to conduct a step test now, after we've had this formation subject to injection for some years?

A. Sure, it could be done.

Q. Why wasn't an updated step test done to check for the integrity of this formation, now that we've got some operational history?

A. Because a step rate doesn't check for integrity of the formation. It checks for the ability of the formation to receive fluid.

But if we refer back to what happened when we did the workover, when we killed the well with brine, it went on vacuum, and the fact is we've never had any problem at all with injection pressure. Our injection pressure -- highest injection pressure has been about 1,500 pounds, which is a full 1,100 pounds below the allowable maximum operating pressure. So we had no reason to do another step rate test.

Q. I'm going to change topics, because I don't believe I asked you this question.

I did ask about your review of the data that preceded the December 2011 MIT. And I think you said after you went back and looked, apparently it did show some discrepancy. It may have been difficult to weed out, based on temperature variations.

But what point in time were you able to trace back where there appeared to be an anomaly between the two pressure areas?

A. As I presented to the Division when we were negotiating that compliance order, et cetera, my best estimate from looking at that data would have been that I saw some anomalous behavior in the late 2010/early 2011 time frame, maybe spring of 2011, maybe as far back as late 2010, but frankly just couldn't discern it from there.

The real conclusive piece of data that convinced me that we had at least a potential problem that we should investigate was the MIT.

MR. ALVIDREZ: May I have just a moment?

(A discussion was held off the record.)

MR. ALVIDREZ: That concludes my cross-examination. Thank you very much.

THE WITNESS: Thank you.

CHAIRMAN BAILEY: Commissioner Warnell, do you have any questions?

COMMISSIONER WARNELL: Yes. Thank you. I have several questions.

EXAMINATION

BY COMMISSIONER WARNELL:

Q. I read through all the pre-hearing statements and all your slides and stuff over the last few days, you have a real good description legally of where the well Number 1 is at?

A. Yes, sir.

Q. Evidently, I've got a false indicator of where your proposed well Number 2 is going to be. Everything I looked at had it 250 feet to the northwest.

A. Northeast.

Q. Northeast, excuse me.

And that's no longer the situation?

A. What we would prefer to do from an operational perspective is to locate the well approximately 400 feet to the south and slightly west of the existing well. So the new location was, as I mentioned earlier, 1,600 feet from the south line and 1,750 from the west line.

Q. 1,600 feet from the south line?

A. 1,750 from the west of the --

Q. Of Section 30?

A. Yes, sir. And that falls within the same unit, K.

Q. We talked a lot this morning about the integrity of the tubing and the casing in the well. We haven't said anything about the pipeline that goes from the plant to the wellhead.

A. That's correct.

Q. Is there any reason to suspect that that needs to be looked at? Or if there's corrosion in the tubing, wouldn't one suspect that there could be corrosion in the pipeline that goes from the plant to the Linam?

A. No, sir. The reason is there's fundamental differences between what conditions are in that pipeline and the conditions that are in the tubing.

That pipeline is a low-pressure pipeline that also has H2S monitors along it, and it is a low-pressure steel pipeline. The pressure in that pipeline is only about 50 psi. So that acid gas -- and that pipeline is constructed to be resistant to that acid gas prior to its compression. And so frankly, it is actually more corrosion resistant than the tubing that's in the well itself.

Q. Thank you. I didn't know that.

You spoke about casing integrity log?

A. Yes, sir.

Q. What type of log did you run?

A. We ran -- essentially, it is called specifically a casing integrity log. What it does is it measures the -- essentially if there's been any potential erosion of the wall thickness of the casing.

And it is -- what that log indicated and what we turned in to the Division was that the bottom 50 feet or so of that casing immediately above the packer had had some corrosion, but still had -- it was not leaking out of the casing, but it did have some corrosion effect.

Q. It's just looking at the idea of a pipe? It doesn't look at the OD, or it doesn't show the total pipe thickness?

A. It does. It's a geophysical electrical log that looks through the pipe, if you will. So it looks at the entire thickness of the pipe.

Q. What interval was that log run on?

A. It was run on the entire casing. But the only -- I mean on the entire casing, all the way to the surface. So I mean the only portion that indicated any corrosion was the basal portion of that integrity log.

Q. In some of my reading I did -- this may not be a fair question, but let me throw it out there. But I read in one of the prehearing statements, I believe Mr. and Mrs. Smiths', that there were numerous problems with the Number 1 well. And then I got to looking on OCD's website, and I saw that there's been 10 amendments to the original order?

A. Yes.

Q. That was an unusually high number of amendments. I don't know if I've ever seen any quite that large before. Do you have any comments on why that order has been amended 10 times?

A. Yes, sir. When the original order was issued, first of all -- and I can't recall, to be honest, every single amendment and what it encompassed, but there were numerous amendments to the order. But most of them were related to -- the original approval required the initiation of operations within a certain time period. I believe it was two years. And it took DCP longer than that to even procure and build the surface facilities, so we had to get an amendment to extend the time to allow. That was one of the first amendments.

Another issue was that the order required that the AGI facility itself have a separate discharge plan and a discharge plan under the New Mexico Water Quality Control Commission regulations for a facility. In the interim from when that facility was designed and constructed, the Division determined that because of the fact that there is no potential for any liquid at that facility, that it was not necessary to have a discharge plan. So the order had to be amended to not have a discharge plan.

And there was some -- that is a situation that was evolving within the Division, how they were going to treat discharge plans at gas processing facilities. So since the order required that DCP have an approved discharge plan, but there hadn't been a discharge plan submitted when the facility was ready to be cranked up, we came back to the OCD and said, "Since this stuff is still in flux and there wasn't been a final determination made on the submitted discharge plan for that facility, we would like to begin operating."

And then the Commission heard that and said, "Okay. It's okay to begin operating, but you are not going to be able to operate at full capacity until that situation is resolved."

And then it was resolved. And then we had to come back again to the Commission to finalize and get it -- basically everything reverted back to the original order.

So right now the order that is in place is almost exactly as the original order was, except for the lack of the requirement for a discharge plan.

Q. Thank you. I'm assuming there was some agreed compliance orders along with these amendments?

A. No, sir. Only -- there was only an agreed compliance order relative to the operation of the well between the time when we detected and reported a problem in December of 2011, to the workover. And then subsequent to the workover, the conditions that we're operating under now.

Q. That's been taken care of, and everybody is fine with that agreed compliance order?

A. Yes, sir.

Q. You talked a lot about diesel in the annular space. What else did operators use, rather than diesel?

A. In a normal well, you have packer fluid in that annular space, and those packer fluids are aqueous based. That's why we don't use them in these dry AGI wells. Because if you have a situation like we had at AGI Number 1, where you have acid gas escaping into that annular space, the last thing you want it to come in contact with is water.

So we use diesel because it's hydrophobic. Also, it's not compressible. And there's a density difference between it and the TAG that allows you to keep it at the bottom of the well, if it ever does get into there, just like what we did, and then to circulate that out. That's for a dry acid gas injection well.

In a wet acid gas injection well, where you're purposefully putting water and acid gas down the tubing, then you do have completely different materials that you use. But then you use a packer fluid that is basically corrosion inhibited brine instead. That's the type of packer fluid most people have in all wells, but it's just not suitable for a dry AGI well.

Q. Looking at one of the C-103s on the website, I recall that originally the request to put diesel in there was denied and later approved. Do you recall any of that?

A. I do recall, at the very beginning, that there was some question as to why we would use diesel. I think -- as I said, this was only the third AGI in New Mexico that was ever put in. The first one, which Marathon put in, has aqueous packer fluid, but that is a wet AGI. They put wastewater, in addition to acid gas, in their well.

The one DCP did in Artesia does have diesel in the back side, and that's kind of the industry standard design for dry AGI wells.

Q. If this second well is approved, your logging program, will it be similar to the Number 1's logging program?

A. No. That's a good point. We're not going to run all of these same logs on the well because we already know what the geology is out there. We're only going to be 450 feet away from the well.

So we're going to run -- basically, we're running basically all of the same logs, with the exception of the formation microimaging log, because it's just not necessary. We use that log to help us pick core points and stuff like that in an area where we drill a well where we don't already have good information on the reservoir.

So here, we're going to run a triple combo, which is a porosity/gamma ray/density log, just to allow us to know exactly where we are, so I can set that intermediate casing immediately above the injection zone. And that's really all that's necessary.

Q. Wouldn't you want to run an FMI out there? To me, that's a good indicator of fractures.

A. We could, but -- I guess I wouldn't have a problem with running an FMI out there. But I would anticipate that it would show exactly the same thing we see in the FMI that we already ran, because we're only 400 feet away. So it would be very unusual to see anything different.

So while we are not planning to do that, I mean certainly that would be something that would be doable and I don't think would be necessarily a problem to do.

Q. You testified that the Number 2 well, if it is drilled and completed, is going to be safer than the Number 1 well?

A. I wouldn't say it would be safer than the Number 1 well. I would say that it would be able -- it would be a more robust design that would be able to better withstand differences in operation and irregularities in operation that would create a potential problem in the Number 1, but wouldn't in the Number 2.

I think both of the wells are perfectly safe in terms of their ability to put gas into the injection zone and for that injection zone to keep the gas in there. Because that's not a function of the well, that's more a function of the geology. But I think it's a more robust design and a more updated design.

Q. One last question. It has to deal with the MIT. I think originally the well was on a five-year program?

A. Yes, sir.

Q. And then it went to two years, then it went to one year, and now you're presently at six months?

A. Yes. The reason is because we know we have some casing above the packer that is compromised. My idea was that once we stack a packer in there and finish the remediation, if you will, of that well, then it would be perfectly appropriate to set that back to a one-year MIT schedule, just like any other AGI.

Q. Would there be any disadvantage to keeping it six months?

A. Well, I mean the disadvantages of just having to do an extra MIT every six months. And I think doing it once a year is prudent, as long as -- the only reason we went to such a short interval was because we know we've got that casing issue and we weren't able to pack it off.

COMMISSIONER WARNELL: Thank you.

CHAIRMAN BAILEY: Commissioner Balch?

COMMISSIONER BALCH: I have a couple of questions.

EXAMINATION

BY COMMISSIONER BALCH:

Q. First of all, I want to follow up on something that Commissioner Warnell was talking about with the casing integrity logs. You indicated that was an electric log?

A. Yes.

Q. It's looking for differences in conductivity as it goes down the pipe and looking for corrosion by finding oxides and metal and stuff?

A. Right. And it's also -- to be honest, Commissioner, I'm not exactly sure exactly how the tool works.

But what it reveals is also any kind of differences in the wall thickness of the casing, and it is also kind of a -- I think it also has a sonic component. So it's basically assessing the casing as it goes down.

By the way, the results of that casing integrity log are in the well file and were submitted for the Division to review while we were still doing the workover to make a determination of where we should put a stacked packer.

Q. Do you know what the sample interval for that log is?

A. It's continuous. I think it's essentially like a continuous log, so it is less than a foot. It's continuous.

Q. I think all log sampling is actually discrete. The line you draw between the points will make it into a continuous datastream?

A. Right. I think that the sampling interval -- I don't know the exact, but it's less than a foot.

Q. If you want to put Slide 18 back up, I'd like to go back and talk a little bit about the free water you talked about. Was it your -- maybe I'm not clear on it. We're not talking about standing water at the base of the well?

A. No, sir.

Q. We're talking about condensation forming on the walls and running down the sides of the tubular once you're at a point where the temperature/pressure differential will allow the water to come out of the TAG stream?

A. Yes. In fact, I was kind of mystified, frankly, when we pulled the tubing, that we had that corrosion in the bottom, but we didn't have corrosion anywhere else in the tubing. I couldn't understand that.

And the only explanation that I can come up with is exactly what you just stated, that the phase envelope is such that we were really getting that condensation very near the bottom of the tubing string.

But we also had a physical issue down there. We had a profile nipple above the packer that allows us to put in a check valve or other kinds of things that you may want to do during a workover. So there was slight irregularity and constriction of that tubing string right there at the base.

So my thinking was that possibly that contributed to an area where that water would run down the tubing, and then it would just stay there for long enough to have that corrosive effect.

Q. Reaction with the TAG? You indicated, I think, from Commissioner Warnell's questioning, that the compression is occurring at the wellhead?

A. Yes, sir.

Q. You have five stages of compression?

A. Yes, sir.

Q. Are there any dehydrators --

A. The --

Q. -- besides the natural dehydration from the compression?

A. No, there is not a separate dehydrator. Probably that would be a better question to ask on the topside facilities. Mr. Boatenhamer could probably answer those better than I can. But I'm not aware of a separate dehydration.

Q. When you sent out the tubulars for analysis, were they able -- this may have been asked already by counsel, but was there any indication of how long it took for that corrosion to occur?

A. There wasn't, really. I mean the indication was that the corrosion may have taken a significant amount of time, months, maybe even a year, to the point where it actually created a pinhole in the tubing. But then once there was acid gas outside the tubing, then it would have accelerated significantly.

What we feel is that we had some small pinholes, in effect. I mean literally, these corrosion spots were like less than a millimeter that we could see inside the tubing. And we had siderite and some other minerals that were indicative that we definitely had to have some water in that string when they did the thin sections of the tubing.

But the idea is that it took some period of time for that corrosion to work its way with through the tubing. But then once the tubing was compromised, that the other larger holes that we saw develop, which appeared to develop from the outside in, were when the acid gas could react with this emulsified diesel and then attack the tubing from the outside.

Q. So with that in mind, do you think the annual MIT is going to be a safe enough interval?

A. Yes, I absolutely do. Especially when, as the Division has suggested in their conditions, that we work out an understanding of what these normal operating parameters are and be able to have an early warning, if you will, of a potential problem and then maybe go out and do an unscheduled MIT. But to do an annual MIT every year, we think that's entirely prudent, yes.

And I would propose that we would continue to do a six-month MIT in Linam AGI Number 1 simply because we already know that we have some casing that has been affected.

Q. On the temperature of the TAG stream, is that also controlled at the wellhead, or is that controlled at the plant?

A. It's controlled at the wellhead. As a matter of fact, the controls -- again, Mr. Boatenhamer would be a better person to ask that question. The controls have been moved off the compressor skid, but the temperature is controlled by louvers on the coolers of the compressors and by a fourth interstage cooler on the fourth stage.

But again, my expertise is not on the topside as much as Mr. Boatenhamer, so it would be better to ask him that.

Q. It's really cooling the stream, not heating it?

A. Yes, it is cooling the stream and not heating it. But the problem really lies in the challenge -- let me put it that way -- the challenge of this temperature control is -- imagine like yesterday, last night, it's like 10 degrees and 30-mile-an-hour winds. And you're blowing against these louvers, and it's a constant adjustment of those temperature controls and feedback louvers to try and keep that temperature controlled.

Also, the entire acid gas line that goes -- it's not very far from the end of the compressor to the wellhead. It's only about 120 feet. But that is all insulated, so that's an added control there. But it is a challenge and -- an operational challenge.

Q. I'm sure you have a seasonal variation of 100 degrees in the outside air temperature?

A. Easily, yes, sir.

Q. The injection well, was it stimulated in any way, or just perfed and washed?

A. Perfed. And we acidized the perfs, and that's it.

Q. The second well will be the same way?

A. Yes, sir.

Q. On the reporting data, it indicated that you're recording every tenth of a second or something like that?

A. Yes.

Q. They're recording all this data and storing it on site?

A. Yes, sir.

Q. There was some questions about what is a good interval to send that data to the OCD for analysis or essentially do what you said and look for railroad tracks. And now temperature may be also a stream of data that's also of interest, injection temperature?

A. It allows you to basically understand what variations you might see in the two pressure tracks.

Q. So what do you think is a good interval for reporting that data?

A. Well, the procedure that the Division has worked and what we had talked about when we looked at the new regs is not -- I mean it is an overwhelming amount of data. So the current thinking in the way that all other AGIs, except this one, are managed in the state is that there is a requirement to maintain those data. Not to report them, but to have them available any time that the OCD would want to look at them. I think that's prudent.

I think there's a separate prudent operator that would have the rigor which I am convinced that DCP has as a result of this experience, the rigor of looking at those data carefully themselves on a continuous basis to make sure that we don't have an indication that might have an MIT issue. But I think reporting and maintaining those data and having them available for the Division when they need them, in conjunction with kind of working out with the Division what is a reasonable operating range for those parameters, is a good system. It's the system that we've implemented at a number of other wells, and it's worked well.

And when we have gone outside those parameters, or when a well has gone outside those parameters, i.e., the Targa well that we talked about, we contacted the Division. We went out there. We looked at the data and said, "Look, it doesn't look like there's a problem because we're seeing some temperature fluctuations."

In this case, it was because of fluctuating amounts of water being injected in the well at different times. We just said, "Let's go out and do an MIT."

So we went out and did an MIT and confirmed that there wasn't a problem, and it allowed us to better get a handle on those operating criteria.

Q. Just a couple more questions, and they have to do with the fresh water.

If you go to Figure 8, I'm presuming some baseline water quality data was collected before injection started?

A. Yes.

Q. Have you compared the new data that you collected with the baseline?

A. Yes.

Q. What were the results of that comparison?

A. I can't tell any difference. There is a variable water quality throughout the area there, in terms of sulfates. We analyzed both of these wells for sulfides and hydrogen sulfides. What we actually analyzed for sulfides and hydrogen sulfides is a calculation that was taken from those analyses, and they were negative.

We do have sulfides that are present in groundwater throughout Lea County quite commonly. I wouldn't be surprised to see them on and off in wells out here. But essentially, the water quality data is not distinguishably different.

Q. You mentioned that there are three fresh water sources in that shallow groundwater, Ogallala in places; and the Dockum, I guess, on top of the red bed?

A. Yeah. Because as you get further into the Dockum, you get above 10,000 TDS pretty quick.

Q. And within a water well that penetrates all three of those, do you expect to see a variation in the sulfides?

A. Yeah. You end up seeing -- depending on where the well is getting most of its water from -- I mean you see the variation mainly in the sulfates. You see -- and chlorides, by the way. You get much more elevated chloride out of the Dockum Group.

So the wells in the area that show elevated chloride concentrations and sulfate concentrations, all other things being equal, are basically wells where either the Ogallala is missing or where the relative contribution to that well is dominated by the Dockum Group.

Q. Can that contribution change seasonally or annually?

A. Absolutely. Especially a well that is completed, say -- where you have the Alluvium directly on the Dockum Group, that Alluvium -- the saturated thickness of that Alluvium varies seasonally. It tends to be, when you've got less water in the Alluvium and you're getting more from the Dockum, it's poor water quality. And when you're getting more from the Alluvium and less from the Dockum, it's better.

Q. So when you did the baseline data, was that done at one time, or was that spread out over some period of time?

A. We looked at the baseline data. As I mentioned, the USGS and the State Engineer has collected data over time, and we looked at all that to kind of get a representative idea of chloride and sulfate concentrations throughout the area.

When we looked at the groundwater most recently, we compared it to samples, for example, that were taken from Mr. Smith's well during the spring and summer of 2011, and then -- I'm sorry 2012 -- and then we did some analyses recently.

But you don't -- seasonally, you don't really see much. Whatever seasonal variation you see is well within the variation that you see from place to place within relatively close proximity in Lea County.

Q. Would you be able to point out the water sampling locations on the map?

A. Yes. Of course, the water samples that were taken from Smith's well are in this location. The water sample that was taken from one of the DCP wells is a well that's located right about here. And then the other one is a well that is located right about here.

Q. Three water wells?

A. Yes, sir.

Q. Is that all of the water wells within the ROE?

A. No. There are quite a number of other wells within that -- well, when you say, "the ROE," there's quite a number of other wells within the one-mile radius.

Q. That's what I meant.

A. Yes.

Q. Figure 7 has them all?

A. Yes.

Q. I'd like to comment on another question Commissioner Warnell had. The second well is, in your terms, a little more robust than the initial well. Would it make sense to eventually turn that into the main injection well and have the Number 1 be the fallback?

A. What my recommendation has been to DCP relative to the operation of those two wells is that there be essentially one well operated for some period of time, and then operate the other well for some period of time, and go back and forth and set up a preventative maintenance program where you are looking at the well that's down when the other one is operating, and vice versa.

My idea is to use both of the wells over time, because I really think it's not a good solution to just have one well sitting there, not being used at all. My proposal is to switch -- we haven't really talked about the details of that, but I think that's one of the things that's on the table.

My thinking is to either inject into one well for six months and then another well for six months and do it that way, or maybe even one of the things that could be considered is to split the stream between both of the wells and inject into both of them.

So I think there's a variety of different things that we want to look at in terms of setting up a PM program and an injection schedule, if you will, that will allow us to use both of the wells and enhance the overall reliability of the system.

Q. So you've worked with a number of these AGI wells? In fact, I've seen you before the Commission on several different cases. Do you think -- I'm just asking an opinion -- that a redundant well would be a good part of any AGI injection plan?

A. Yes. Do I think it's necessary? No. But do I think it provide added reliability to the overall injection system? Yes.

COMMISSIONER BALCH: Those are my questions. Thank you.

CHAIRMAN BAILEY: The hard part about going last is that most of my questions are already taken. But I still have a few for you.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. Using both of those wells either as alternating or simultaneously, if the design for Number 2 is the new and improved version, can the Number 1 be retrofitted to reflect some of these improved design systems, such as the fiber optics and the corrosion-resistant tubing?

A. Funny you should ask. We talked about that on the way home from the hearing this morning. I said, "We certainly -- when we go stack a new packer in there, we could stick 1,000 feet of corrosion-resistant tubing, just like we had planned for the Number 2, into the Number 1. And we could put fiber optic down there to measure injection, temperature and pressure at the bottomhole." So certainly that could be done.

Q. And diesel to include corrosion inhibitors and biocides in both 1 and 2?

A. That's already in the Number 1. Yes, ma'am.

Q. You mentioned that the casing integrity log was run from TD to surface. Was the cement bond log also run to surface?

A. Yes, ma'am.

Q. And did it show any channeling or major areas of lack of good cement bonding?

A. No.

Q. Not even through the thief zone?

A. I guess I'm trying to understand your question, whether it was -- in the original cement bond log, when we ran, yes. Obviously, when you run cement over 8,600 feet, there are places where it's better or worse. And in the thief zone, the quality of the bond log is probably not as good as it is in other zones. I can't remember exactly, right off the top of my head, what the whole bond log looked like.

But when we originally looked at the bond log back in 2005, we were convinced that we had a good cement bond in general throughout the location. It was probably worse across the Glorieta. That was a very frustrating zone to drill through.

By the way, that's 3,000 feet above our injection zone.

Q. Let's go to Slide 9, which does indicate some faulting in the general region?

A. Yes.

Q. Because of the headlines that are so apparent that we see on a real regular basis, and for the nongeologists who may be reading this transcript, too, would you comment on the potential for earthquakes as a result of any kind of injection in either the 1 or 2?

A. I don't believe that there is any increased likelihood of earthquakes. This is not a very seismically active area to begin with.

These faults that we identified in the seismic basically peter out below the Lower Bone Springs, so they really are faults that were more a result of Precambrian basement uplift of the Central Basin Platform.

And then these later Pennsylvanian and Permian rocks drape over those faults, so they really have not been reactivated. The faults peter out below the injection zone. I don't believe that there's an enhanced earthquake risk.

Q. I just wanted that on the record. Thank you.

MR. ALVIDREZ: We'll find out tomorrow.

THE WITNESS: Yeah. This may be a moot

point if some people believe that the world will end tomorrow. I still have plans for the weekend myself.

Q. (By Chairman Bailey) Exhibit Number 7, with the lab results from the water analysis, I did hear you say that sulfides are calculated from the sulfates?

A. No. I'm sorry, Madam Chair, if I misspoke. What I said was that H2S is calculated from sulfides. The sulfates and the sulfides we actually measure separately.

Q. And these analyses do not show sulfides at all?

A. That's correct.

Q. Is there a different technique for gathering samples when you are asking the laboratory to analyze for sulfides, as opposed to sulfates?

A. Yes.

Q. Would these analyses be -- would these samples have been gathered to account for any sulfides that may have been present in the water?

A. The original samples were gathered strictly for anion and cation analyses, not including sulfides. Those were gathered in unpreserved, regular sample containers.

Then since we decided, well, it probably would be good to have sulfides to compare with some of the data that Mr. Smith had provided, we went back -- that was on Thursday we collected the samples just for standard anion and cation. And then Friday we went back and collected the sulfide samples, and that's why you have two different dates on here.

Q. I'm looking for the page that would tell me if there were sulfides present or not and/or detected. Would that be on page 5 of 9?

MR. RANKIN: Madam Chair, if I might interrupt here? Those datapoints were not requested by the Division, so we didn't feel we could present those on direct as a direct exhibit. We have prepared them as rebuttal exhibits to Mr. Smith's testimony, if that's okay. But we do have them available and will be presenting them on rebuttal.

CHAIRMAN BAILEY: Okay, thank you. Those are all the questions I have. Thank you.

Do you have any rebuttal for the questions that were asked in cross-examination?

MR. RANKIN: Just a few points to touch on on redirect.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Gutierrez, there was some discussion about the idea that there should be some parameters, operational parameters, which would be triggerpoints for notification to the Division. In your experience working with the Division, have those parameter points been something that are locked in, or is it something that is administratively determined between the Division and the operator?

A. The latter. What we do is we sit down with the Division and look at the operational data once we get a well running. And we say, "Okay. What's reasonable, in terms of what we would expect, and what are going to be the steps, besides just notification?"

I mean once we notify the district -- let's say if I call up Mr. Gonzales or Paul at the district or whatever and say, "Look, Paul. I've got these datapoints. They look a little squirrely to me. I want you to look at them. They are kind of outside our band of parameters that we're looking at," then I transmit those data to him. And we put our heads together and go, "Do we want to watch it a little longer, or do we want to go out there and do an MIT?" And I think that's the way to go about it.

Q. And part of the reason for that is because conditions may change in the formation? There may be operational issues that -- as you pointed out earlier, there are a number of factors that go into what these parameters are. So it would be best probably to have that be a communication between the Division and operator to determine what those parameter should be; is that correct?

A. That's my opinion. I think that's the best way to do it.

Just to give you a very simple example, when you first complete one of these wells and you fill it up with what I call cold diesel, because the diesel that you get delivered is essentially 70 degrees or whatever the ambient temperature is. If we were have having that diesel delivered today, it would be a lot colder than 70 degrees.

But anyway, you put that diesel in, and you fill it up to the very top and then seal it, then you have essentially zero pressure on the back side because you don't pressure it up. You just fill it to the top.

If you just wait two weeks, without ever injecting a single drop of anything into the well, and you go out there, you'll have 5-, 600 pounds on the back side. Because what happens is that diesel has now heated up from the surrounding rock, and you have to actually relieve some diesel at that point to bring the pressure back down so you can set it up.

What I'm saying is these are complicated relationships between pressure and temperature and stuff. And in order to have some operational flexibility, you have to be able to look at those things. But if they kind of go outside a range, it's not diagnostic that you have a problem. That's why we do MITs. MITs are the gospel. When you do an MIT, you know if you've got a problem or you don't.

And that's why I think these parameters are useful for understanding what's going on in the reservoir and the well. But really what they do is serve to alert you, if you will, of whether you need to do an MIT.

Q. Mr. Gutierrez, moving on to the issue that was raised by Mr. Alvidrez, the analysis that you did of the wells that penetrated the formation, that analysis is exactly what the Division required, which is to say that you provide a schematic of the wellbore and a review of the information contained on the Division's website of the cementing and casing details; is that correct?

A. That's correct.

Q. That's all the Division requires. And that's sufficient, unless there's some identification of an issue there?

A. Yes. If there's an identification of an issue, typically we've been required, as we have on other locations, if there's a potential problem, to go back and actually address the remediation of those wells. But that was determined not to be the case here. And as I mentioned with the one well that we were looking at in detail, frankly, it didn't even penetrate the injection well.

Q. On the Goodwin Number 3, which is the one that is highlighted, it's got a total bottomhole depth of 7,020. And that's the one you pointed out that was not actually penetrating the injection interval; is that correct?

A. That's correct. It's got a plugged back depth. It was drilled a little deeper than that.

Q. Right. Down to 8,582?

A. That's right.

Q. So the point you were trying to make is that even though it's from the same formation, there may be different members, geologic members, within the formation?

A. Yes. The upper portion of that is the caprock.

Q. So they're actually distinct sort of geologic formations in that sense? I mean they're within the same formation, but it's a distinct geologic characteristic?

A. I couldn't call it a distinct formation, but a member I would agree with.

Q. So it's got a slightly different geologic characteristic?

A. Yes, sir.

Q. And that's why you made the point that it didn't penetrate the caprock and still operates as a good seal?

A. Yes, sir.

Q. The other point I'd like to make on that well is if that plugged and abandoned oil and gas well were actually operating as a conduit, wouldn't you expect to see a continuous flow of H2S? If it were acting as a conduit or a source for the acid gas injection, you wouldn't expect to see a discontinuous source of sulfides, would you?

A. No. Frankly, I wouldn't expect to see anything. I don't see how I could get any acid gas anywhere through the caprock and, most certainly, not through that thief zone. That will swallow everything and the kitchen sink.

Q. On the AGI Number 1, I want to make the point briefly that you made earlier, which is that while the AGI Number 1 doesn't have all the enhanced features of the AGI Number 2, as of November, it withstood a 3,000-pound MIT test; is that correct?

A. Yes, sir, it did.

Q. So in your opinion --

A. No. I'm sorry, no, not as of November. It withstood a 3,000-pound MIT test when we did the workover in May. It did a 550-pound MIT in November, which is the normal MIT that you would do.

A 3,000-pound test you never would do, unless there was a specific reason to really try and stress the casing. And that's what we had when we finished the workover.

MR. RANKIN: Thank you very much, Mr. Gutierrez. Nothing further.

CHAIRMAN BAILEY: Then you may be excused.

THE WITNESS: Thank you so much.

CHAIRMAN BAILEY: You may call your next witness after a 10-minute break.

(A recess was taken.)

CHAIRMAN BAILEY: Mr. Rankin, would you like to call your next witness?

MR. RANKIN: Thank you, Madam Chair. My next witness is Mr. Roberto Torrico.

Do you want to swear in both of our additional witnesses?

CHAIRMAN BAILEY: No. One at a time.

(The witness was sworn.)

THE WITNESS: Good afternoon.

MR. RANKIN: Madam Chair, Commissioners, we have a demonstrative exhibit to assist with Mr. Torrico's testimony today. I've presented you each with a hard copy for your reference.

ROBERTO TORRICO

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

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

A. My name is Roberto Torrico.

Q. And can you please tell the Commissioners where you reside?

A. In Denver, Colorado.

Q. By whom are you employed?

A. By DCP Midstream.

Q. What is your position with DCP Midstream?

A. I'm a senior project manager.

Q. And what are your duties as a senior project manager?

A. I do project management for gas plants and AGI wells.

Q. And have you previously had the occasion to testify before the Commission?

A. No. This is my first time.

Q. And in that case, can you please summarize briefly your educational background?

A. Yeah. I have mechanical engineering from San Simon University in South America, and postgraduate in oil and gas engineering from Santa Cruz University in partnership with Oklahoma University.

Q. And can you please briefly review for the Commissioners your work experience in the oil and gas industry?

A. I have 20 years' experience in the oil and gas industry, working at production, processing and acid gas injection, having worked in major oil and gas companies like Petrobras and Kinder Morgan here in the United States in the Permian Basin.

Q. You mentioned that you worked on AGI wells, CO2 injection wells, and acid gas injection wells?

A. Yes. I worked in South America and in West Texas in Permian Basin injecting CO2.

MR. RANKIN: Madam Chair, I would like to tender Mr. Torrico as an expert in AGI design and operation and petroleum engineering.

CHAIRMAN BAILEY: Any objection?

MR. ALVIDREZ: No objection.

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: He's so admitted.

Q. (By Mr. Rankin) Can you please explain briefly -- Mr. Gutierrez went through in detail some of the lessons learned. But from DCP's perspective, can you please briefly explain the operational lessons learned from the AGI Number 1 experience?

A. Yes. Basically, we learned that we need to have more frequent monitoring of the parameters, the injection parameters, of the acid gas, and improve the operation, the controls for operation, to do a better operation during the period of time that we need to operate these acid gas wells.

The most important was the temperature control relocation and programmable logic control system detecting the alarming points that could be critical for operation of these gas wells.

Q. Mr. Torrico, in addition to the operational issues, there are also some design elements that DCP has learned would enhance the AGI Number 2 well. Can you just briefly summarize some of those that DCP has identified as being important?

A. Yes. Well, the configuration of the well, we are going basically to the same formation that we have in AGI Number 1. The tubing size basically is the same. We are going deep with the casing.

The most important thing is the enhanced corrosion resistance that we have with these new materials. Basically, we are adding more nickel and we are adding more molybdenum into the material in order to have better performance under the most critical conditions that this well can handle, basically, based on the historical information of the analysis obtained for the past operation under the AGI Number 1 injection process.

Q. In addition, you mentioned -- Mr. Gutierrez mentioned that there was a fourth string of casing that will help protect the well during drilling?

A. Yes. We are going basically down into the top of the injection zone, trying to prevent whatever uncontrolled situation we can have during the drilling process and initially overprotecting the aquifers that we can go through during the injection process and when we're going into the operation phase.

Q. And these elements of the AGI Number 2 are demonstrated in this demonstrative exhibit?

A. Yes, sir.

Q. Any of these elements or features that DCP has opted to include, are these being required by the Division in any way?

A. No.

Q. These are design elements that DCP itself has decided to include in the design; is that right?

A. Yes, that's right. It's DCP's choice.

Q. Mr. Torrico, it's a choice that will be more costly. But in the end, it's something that DCP feels strongly about in order to enhance the design; is that correct?

A. That's correct. It's in the best interest for DCP to have a more strong design for this new well.

Q. Mr. Torrico, in your opinion, will having a second AGI well on the facility enhance and improve the operations overall with the AGI facility and the plant?

A. Absolutely. It improves the overall integrity of the facility and initially permits have a less possibility to have releases because we are having a second well we can inject this acid gas, and we can operate under whatever conditions we can handle with one or another well.

Q. The releases you just mentioned, is that when you shut down -- if you have to shut down the AGI Number 1, you have to flare back at the plant in order to clear out that line; is that correct?

A. That's correct.

Q. So if you had two wells, you would be less likely to have to flare back at the plant; is that right?

A. That's correct.

Q. Some of these design elements that you've identified are essentially enhanced materials, getting more data, and you've got improved operational controls through having two wells and the flexibility to operate those wells?

A. That's correct. I'd like to explain a little more about these two points. It was DCP's idea, based on my experience, to have these downhole sensors that senses the pressure and temperature because we had experienced the same situation in some wells in Brazil and Bolivia. And for that reason, we recommend DCP to have these downhole sensors in order to detect whatever conditions we can handle progressively and be proactive and predictive into whatever condition we can handle.

It's basically an enhancement that we are expecting to have in the well, that we are trying to put in this instrumentation inside the well, in the downhole of the well.

Q. Mr. Torrico, the additional well, in your opinion, with these enhancements, will it improve the reliability of the facility overall and reduce potential impacts on the environment and human health?

A. Yes. Additionally, it's in DCP's best interest to prevent and protect all the overall adjacent neighbors around the well. And it's part of our philosophy of our company to have the best protected well and facility, too.

Q. Mr. Torrico, finally, did you review the Division's proposed conditions that were part of the prehearing statement?

A. Yes. DCP agrees with Points 1, 2, 4, 5 and 6. And Point Number 3, we should be continuing reporting for AGI Number 1 until we replace the packer. And it is essential to continue to do the same thing for the new well because the new well could be more enhanced if we have a better -- most robust design.

Can I return to my last explanation about operating with these two wells at the same time? We expect to have a programmable logic control system that can split between these two wells without exceeding the maximum operating pressure in the wells. If some day we need to operate these two wells at the same time, we can do it without exceeding the maximum injection pressure.

This we'll handle electronically in real time via a PLC system, according to the plan requirements. We have actually plans of a DCS control system, a distributed control system, that is handling actually operation of the plant and the AGI well, too, at the same time. What we expect to do is link into the same system in order to have the same protocol to handle all the processes and retrieve all the information for better control.

Q. Mr. Torrico, can you please just explain for the Commission what exactly "PLC" means?

A. It's a programmable logic control. Basically, you introduce a mathematical formula to do some calculations and controls during the operational time that these cards -- basically, it's an electronic card -- is doing during the operation.

For example, if you like to control the maximum temperature and send a signal to one of the instruments that you have -- for example, activate and close one valve. If you have an excess of temperature and pressure, you can do that. It's basically a logic system that can permit you to control without human interaction whatever reaction you need to have for safety reasons, for control or for quality control process.

Q. Thank you, Mr. Torrico. So essentially, it's a higher level of feedback, based on the parameters that you would find; is that correct?

A. That's correct.

Q. Mr. Torrico, is it your understanding that the Division and the District Office -- first of all, you worked closely with the Division and the District Office on the design; is that correct?

A. That's correct.

Q. And it's your understanding that the Division and the District Office support DCP's application?

A. Yes.

MR. RANKIN: Madam Chair, I have nothing further.

CHAIRMAN BAILEY: Any cross-examination?

MS. GERHOLT: I have no questions for this witness.

CHAIRMAN BAILEY: Mr. Alvidrez?

MR. ALVIDREZ: Yes, ma'am, a couple of questions.

Good afternoon.

THE WITNESS: Good afternoon, sir.

CROSS-EXAMINATION

BY MR. ALVIDREZ:

Q. I wanted to get a little more clarification. If I understood your testimony, DCP at least wants the option to operate both the AGI Number 1 and AGI Number 2 simultaneously; is that a correct understanding?

A. It's an option. What we prefer is operate with one well and with another. But like Mr. Gutierrez told, we are having a big investment in this well, and it's preferential we can use these two assets. But our preference is work with one, basically work for six months with one, and go to the second in the next six months.

It's for maintenance purposes. We need to do some maintenance in the well that's regular work that we need to do on the well. And we need to stop the injection in this well, and we need to go to the other well in order to maintain the pressure of the plant because it's dependent -- the plant depends on injection. If we don't have injection, we need to stop the plant. And this is a big impact for the company, economic impact for the company.

And in this case, if we are trying to handle these two at the same time, we are distributing basically the flow into the reservoir in a more uniform way, basically trying to do that. It's beneficial for the same reservoir, too.

We understand we can handle it both ways. Basically, our limitation is the pressure of the reservoir. The maximum pressure we cannot exceed, and we have this very clear.

Q. That's really what I was wanting to get at, is the last part of your answer, in terms of the maximum pressure. How do you gauge that or assess that you not exceed the maximum pressure?

A. Good question. Thanks for that. We have a pressure control system in place that actually is working. And with this pressure control system in place, we detect maximum pressure coming from the compressors. And if we are arriving close to the maximum pressure, basically we reduce the compression. It's a logic control work, basically. It's what the actual logic control is doing. We expect to do the same thing in the second well.

Q. Will the operation of both wells simultaneously mean you can increase the throughput through the plant?

A. Well, if you -- we have actually 225 million in the plant processing, and at any time we expect to exceed more than 7 million standard cubic feet per day of injection. And the maximum amount of CO_2 that we can receive, according to our simulations, we are not expecting to exceed more than 7 million cubic feet per day of injection in volume.

And in pressure -- we have only two compressors there. We cannot exceed, because these two compressors are limited by a control system and actually by the flow they can inject.

Q. So does the answer to my question about whether the operation of the wells simultaneously mean that you won't be able to increase throughput through the Linam plant?

A. We don't, because we have compression limitations, actually. We have maximum flow that we cannot exceed because we have maximum flow that we can compress at the AGI site, and we cannot increase the process inside. Because if we increase the process inside the plant, we are going to increase the injection volume, too, the injection flow, in this situation.

Q. Now, as part of your responsibilities, I guess you oversee a number of AGI wells operated by DCP?

A. Actually, this is my assignment. I'm working with compression stations and gas plants, too. It's under my command. I'm handling actually four projects, yes.

Q. Is this work you're doing on all new installations only, or are you looking at current operating wells?

A. Expansions of plants, new compression stations and new plants.

Q. What is your -- do you have a specific territory that you cover or region that you cover?

A. Not actually. I'm covering from the north part of Colorado to the south part of Texas and actually New Mexico, too.

Q. Anything out of the U.S.?
A. Not actually. I was doing this before, but actually, no.
Q. Have you worked with acid gas -- well, let me ask this: How many acid gas injection wells have you got experience with?
A. Well, when I was working in Kinder Morgan in West Texas, Maryland, I have under my command the injection of over 1,420 gas wells, 1,422 EOR wells, enhanced oil recovery wells. Basically, we inject CO2 to increase the pressure in the reservoir and recover all the oil. That was a service we provide for different companies like Chevron, Oxy.
Q. What about acid gas wells, such as the one?
A. This is an acid gas well, a CO2 well, yes.
Q. In your experience, have you seen situations where the operation of an acid gas well has contaminated an aquifer?
A. Well, what I noticed was that in the past, in Brazil -- this occurred in Brazil. Basically, one of the injection wells where I was working in operations had a problem with an instability, geologic instability that took place that broke the cement and basically damaged -- very bad damaged the part where the aquifer was.

And this action of the geological formation over the well, over the casing of the well and cement, broke the cement and broke the casing, basically. That was the only experience I have with this situation.

The national company at the time -- the environmental division of the national company in Brazil, Petrobras, was looking for sensors around the well. And they detected a small radius, basically, of the immigration of this contamination. I think it was no more than 1,000 meters.

Q. Are these underground sensors?

A. Yes.

Q. Are there underground sensors with either of these two wells, the DCP wells that we are talking about today?

A. I don't know, but we are going to have these sensors downhole.

Q. You talked about some of the sensors. I understood they would look at pressure and they would look at temperature, but I didn't understand that they would be doing any type of chemical analysis.

A. No, no. We are not expecting that because we are very far from whatever aquifer formation we can be interacting. And additionally, we are going to have four casings.

Second, we don't have any experience or historical information about seismic problems in the area to be aware and put the sensors there.

Q. Are there sensors that are available in the industry -- and I'm not talking about surface sensors necessarily, but subsurface sensors that can detect whether or not an operation is leaking either CO_2 or H_2S?

A. Normally, every chemical has their own detector because every sensor has a different type of catalyzer that activates and detects.

H_2S has one, and ASTM has a protocol to have these analyses. And some companies produce these sensors, but I think there are no more than five companies here in the United States that are producing these sensors.

Q. I take it there are no plans to put these types of sensors in with respect to either the existing well or the new well that you're proposing?

A. We are not expecting to have them because, like I explained before, we have four strings, four casings. We have these subsurface sensors. And we have additionally a protection -- we have a south dome over the reservoir that is protecting -- basically, we have over the south dome close to zero migration. And we are not expecting to have this, especially because we have four strings protecting the aquifer.

Q. What you're saying is you don't think that those types of sensors would be warranted in this application?

A. I don't think so.

MR. ALVIDREZ: I have no further questions. Thank you very much.

CHAIRMAN BAILEY: Commissioner Warnell.

COMMISSIONER WARNELL: I have no questions.

CHAIRMAN BAILEY: Commissioner Balch?

COMMISSIONER BALCH: Good afternoon, Mr. Torrico. I have a couple questions.

EXAMINATION

BY COMMISSIONER BALCH:

Q. In your Brazil example, where there was a casing failure due to an earthquake, apparently, and then they were monitoring the migration of the CO2, were they doing that with surface flux measurements?

A. Yes.

Q. So they had a device that they took around and measured to see if CO2 was --

A. Yes, sir.

Q. And groundwater sampling?

A. Yeah.

Q. Those are the two ways that I know of to monitor CO2 migration to the surface directly. Indirectly, you might be able to use microseismic, I guess?

A. That was microseismic, according to the information I have. I was not directly involved with the team working with the sensors, but it is information I know. I don't know exactly the instrument or the technology used to do that. I cannot tell you exactly.

Q. You worked for Kinder Morgan?

A. Yes.

Q. And you had involvement with a great number of CO2 Enhanced Oil Recovery projects?

A. The operational side --

Q. But from --

A. -- and the design in two wells only.

Q. Do you know, is it typical to routinely -- what sort of monitoring for CO2 or H2S leakage is routinely -- in an EOR, there's not going to be any H2S. But is there any routine monitoring for CO2 leakage around an EOR project?

A. What we had in Kinder Morgan was only the surface of the well sensors. We had H2S and CO2 sensors in the surface. The only thing in Brazil was complicated was the fact that Brazil has mercury in the gas, too.

And it was a complicated thing to measure, too, to put through catalyzers, in order to reduce the amount of mercury going into the well in the injection process.

But here we don't have this situation. And according to the work we were doing in Kinder Morgan, basically, we had only these surface detectors if we have a leak in the surface, and we had only the pressure sensors in the annular space detecting if we have high pressure or not. That's what we have.

Q. So I think what you said was that people are not routinely drilling monitoring wells? They're using surface measurements and existing groundwater to check for leakage?

A. Oh, yes.

Q. All right. So you were discussing kind of a process monitoring system that they run at the Linam plant?

A. Let me clarify this point. There was a question before. All these actions that I know, I like to clarify that every company has their own policies. And in the case of the company I was talking about, they had their own geology analyses, similar to like this well has.

And according to their geology, they haven't any information about seismic situations or related geological failures that can affect a well and they need to have a detection system there in place.

Additionally, I don't know what the difference actually between New Mexico and Texas could be in regards to these requirements. I think actually New Mexico is improving a lot in their requirements.

But in the case at the time I was there, we had no requirements from the state to have these sensors there because we justified by geology, basically.

Q. So at your Linam plant, you have a process control room, I'm assuming --

A. Yes.

Q. -- with a monitor for every step of the process that you're doing in separation and creating the various streams of gas that you're trying to distribute, TAG or methane?

A. Um-hum.

Q. Are you talking about taking the sensor data from the AGI Number 2 well and tying that directly into that process monitoring?

A. Yes, in the DCS, in order to have the possibility for the operators to see if they have an alarm or not coming from the well.

Q. That's monitored 24 hours a day?

A. 24/7, yes, sir.

Q. And in those sorts of systems, you can set fail safe levels or triggerpoints where certain things will happen?

A. Yes.

Q. Is it possible to automate the system to the point where if AGI 2 is having a temperature problem -- well, temperature might not be a good example -- a pressure problem, would you be able to flip it to the AGI 1 directly from a control room? Or does somebody have to go to the field and --

A. Normally, it's necessary to go to the field, because you don't know exactly what conditions that the well has at that time. You need to send an operator over there. Normally, it's a process that takes more than two hours, and the operations are not far from there.

For safety reasons, we prefer not to activate one well automatically because we don't know what happens around it, if we have valves closed, if we have some problems that can affect the safety of the operation.

Q. Or a bad sensor?

A. Absolutely.

Q. So there's a couple-hour delay between switching one well to the other?

A. Normally, that's the time, in my experience, because of the distance that we have from the plant to the well.

Q. For that time period would you be able to close the pipeline from the plant to the well? Would you have to flare back?

A. I think it's necessary to -- because you're increasing the pressure. The pressure is not like a PSV release type when you have one of these releases inside the well. The pressure will go up slowly, and you have enough time to close the well, open the second well, and maintain the same pressure in the pipeline. You don't need to close the pipeline during this period of time.

Q. Right. I believe, and I may be wrong, that the current order limits injection through maximum pressure, not by volume?

A. Yes, sir, that's right.

Q. The question was brought up by Mr. Alvidrez, would you be able to then kind of -- perhaps the intent of the original order was to have a volume limit, but it was instead applied as a pressure limit. Would you be able to circumvent that implied volume limit?

A. I consider pressure a more critical variable to control because you have various factors. You have the porosity. The permeability can be affected. And pressure basically is the main driver for whatever problems you can have in a reservoir.

But I don't see any improvements in this control. We have flow control to doing that at the same time. If we have one variable, like the pressure, that is critical for this process very well controlled and regulated, I think it's enough.

Q. The Linam plant, is it running at full capacity?

A. Yes.

Q. And it's producing about 4 to 5 mcf a day?

A. Yes, 4.5, 5.

Q. And to increase that amount of TAG, you would have to significantly upgrade the facility? Or can you increase --

A. Actually not, because we have enough room. Maybe if we add additional maybe 10 percent over this, we need -- and we have plans to do that, too.

Q. You can easily do about 10 percent more, which gets you to four and a half to five and a half, 9 cubic feet?

A. Yes. Maybe Mr. Steve will explain a little better that because he's in the daily operation.

My understanding is that the plant has enough capacity to handle this 10 percent. But we have plans to increase some equipment around it, too, if we need --

Q. I believe the original order -- most of the testimony for the original order and for the subsequent modifications to it involves the analysis of a 7 million cubic feet a day maximum for the plant?

A. Um-hum.

Q. Do you see that plant exceeding that limit any time in the next 30 years or 25 years?

A. I don't think so. What we did in our economical analysis in the Business Development Management Group is see how much capability there is to receive more gas from different producers there could be in the next future years. And we don't see any excess of no more than 6.2 million, maybe, in the best case scenario.

But actually, we are not expecting, at least in the next 15 years, to have an excess of 6.2. I don't know. If the oil price goes over 150, maybe somebody can try to inject more -- can try to produce more oil from EOR type of wells, maybe. But it's an unusual situation that we are not considering.

We are considering, according to our normal analysis, that this cannot exceed 6.2 million.

Q. Okay. So I think that the remaining concern, perhaps, might be there's a limit of 2,600 and some psi maximum injection pressure?

A. Um-hum.

Q. If you hit that into both wells at the same time, what would your rate be?

A. Good question. I think we cannot exceed this pressure because we have only two compressors. Every compressor has capability to inject only 5 million at this maximum capacity flow.

Q. So even if you were to optimize your plant, receive dramatically more throughput than you expect or project, the most you would be putting in is 10 mcf a day from those two compressors?

A. If we do modifications to the compressors, maybe. Because actually, the pockets in the compressor in every cylinder has capability for less than 5. I think maybe Steve will clarify that.

But my understanding is we are below 5 million for every compressor because of the optimization of the process. You know, when you have a combination of CO_2 and H_2S, you need to reduce the pockets in order to have more efficiency in the compressor. That's the situation we have.

Q. And to upgrade that requires a significant expense in custom compressors?

A. Yes.

COMMISSIONER BALCH: Those are my questions.

THE WITNESS: Thank you. Good questions. I appreciate it.

CHAIRMAN BAILEY: Are you the person to talk to about the temperature control systems, or is the next witness?

THE WITNESS: I think the next witness, because he's experienced in that. He has various suggestions he makes and sends his various suggestions to do better enhancements and control better, to do some enhancements and control because he's working 24/7, and he has more maybe data to share. I can only talk generally. But if you'd like to discuss this in more detail, maybe Steve Boatenhamer can be the person that can talk about this point.

CHAIRMAN BAILEY: Then I will ask him my questions, and I have none for you.

Do you have any redirect?

MR. RANKIN: Madam Chair, thank you. No, I have no further redirect.

CHAIRMAN BAILEY: Then you may be excused.

THE WITNESS: Thank you very much.

CHAIRMAN BAILEY: Would you like to call your next witness?

MR. RANKIN: Madam Chair, Commissioners, I'd like to call my next witness, Mr. Steve Boatenhamer.

STEVE BOATENHAMER

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Boatenhamer, can you please spell and say your full name for the record?

A. Steve Boatenhamer. S-t-e-v-e, first name. Boatenhamer, B-o-a-t-e-n-h-a-m-e-r.

Q. Thank you, Mr. Boatenhamer. Where is it you reside?

A. Hobbs, New Mexico.

Q. By whom are you employed?

A. DCP Midstream, LP.

Q. What is your position with DCP?

A. I am the Linam plant manager, operations manager.

Q. And your duties as a plant manager include what?

A. Day-to-day operations of the largest natural gas facility that DCP operates in the State of New Mexico.

Q. Those day-to-day operations include oversight of the safety and environmental issues that go on at the plant; is that correct?

A. That's correct.

Q. It includes not only the plant, but the well facility, as well?

A. Yes, sir.

Q. Which is approximately a mile and a half north?

A. Correct.

Q. Have you previously had occasion to testify before the Commission?

A. No, sir.

Q. And you're testifying today as a nonexpert fact witness; correct?

A. That's correct.

Q. Mr. Boatenhamer, can you please review your work history with DCP?

A. I started at Linam Ranch in 2001 as a relief operator, utility operator, which is at the bottom, an hourly classification.

I progressed up to plant operator, up to a lead operator, Operator 3. From then I was given an assignment for management for the Eunice plant facility, which is located south, with DCP Midstream. That was in 2007.

And I just recently have come back to the Linam Ranch plant as the plant operations manager.

Q. In your role as a Level 3 Operator at Linam and also as a plant manager at the Eunice plant, you have become very familiar with operations related to acid gas facilities; is that correct?

A. Correct. As we've heard from several individuals today in the testimony, Linam had a Sulfur Recovery Unit or reduction unit that I was experienced with operating for several years, not only as an operator, but lead operator, as well.

At Eunice we had a Sulfur Recovery Unit down there, as well, that is still in operation today. So I am familiar with the removing of acid gas in the sweetening system and processing it via sulfur recovery or AGI.

Q. From an operations standpoint, can you just briefly summarize some of the specific reasons, the sort of highlights, for why DCP is seeking a second well injector?

A. As we've heard, you know, we had the issue with AGI Number 1 with the MIT. Through that process, we worked with the Division and the leadership of DCP to come to a point to where we could safely work that well over.

By having a second well, it will mitigate some of those issues where we're asking thousands of producers to shut in on an unplanned shutdown, kind of in a reactive mode, where there was a possibility of venting or flaring across the County of Lea and Eddy County, maybe more so in an uncontrolled atmosphere.

Q. So based on that, those considerations, and the impact it had on operators and the impact it had on the plant, potentially, when you shut the AGI 1 in, and you had to flare back at the plant, it was decided that a second well would help improve reliability; is that correct?

A. That's correct.

Q. Can you go into more detail about how the Division -- how the discussion with the Division progressed with DCP to arrive at that decision for a second well?

A. Back sometime during the well workover with Mr. Gutierrez and Mr. Gonzales, there was some -- it was first brought to the surface when we were going through the process of working over AGI Number 1 in April of 2012, is where that initially started.

As it progressed, we took the recommendation or the starting of the dialogue and looked at it, evaluated it as a corporation, and come to see the benefits of AGI Number 2 for the Linam Ranch facility.

Q. Let's talk a little bit about the decision to change the proposed location of the well. In fact, Mr. Boatenhamer, it was it your idea, wasn't it, standing out there, looking at the proposed site, to say, "Let's maybe move this a little bit to the south, that way." What would be the benefit of that?

A. Correct. Looking at the location -- of course, when the first C-108 was filed, it was northeast of the existing Linam Ranch Number 1.

As we went out to look at the MIT and a little before that, we talked about the prevailing winds in that area are out of the southwest to the northeast. I had the concern of it being to the northeast of Number 1.

One reason for us to have both wells is if we encountered a problem, we could work one over and do it in a safe manner while the other one was in operation. So that was one point, was to move -- that was one thing that I had some concerns about.

Also, by moving it directly south or south and slightly west of Number 1, if there was a potential release, it would stay on DCP's property. It wouldn't be up on the northeast corner of that, as far as the perimeter monitor. And last, but not least, it would be further away from Mr. Smith's property.

Q. In addition to those considerations, isn't it also true that you evaluated the proximity to the plant, the proximity to the pipeline, and decided it also made prudent sense to locate the AGI Number 2 in the new proposed location?

A. Correct. Around the transport of where the acid gas injection comes into the facility, it fit where we would tie in this Number 2 well with the existing facilities that we had at the Linam Ranch well site. Correct.

Q. So in addition to any safety concerns or safety thoughts, it also fit very well with the operational decision, as well?

A. Correct.

Q. In your understanding, the Division and the District Office agree with the new location?

A. Yes.

Q. Are you aware of any other AGI wells in New Mexico that have as stringent conditions and requirements as that AGI facility that you operate?

A. No, sir.

Q. Did you hear Mr. Gutierrez's analysis of the problems that led to the tubing leak in the AGI Number 1 well?

A. Yes.

Q. Based on Mr. Gutierrez's testimony, he indicated that was a condensation issue resulting from a fluctuation in temperature?

A. Correct.

Q. Based on his recommendation, he indicated that DCP should address the temperature control fluctuations. And how did DCP do that?

A. As we went through and investigated that, it was brought to our attention that temperature control was less than adequate.

Just to kind of paint a picture around this temperature control, we have a cooler box. The well site compression has four stages of compression. This cooler box has four stages of cooling leaving each stage, 1 through 4. The cooler box is equipped with louvers for each stage. Internally, as well, it has a recirculation set of coolers or louvers, and then it has an external set of louvers on the front end of that.

The cooler was controlled with a pneumatic-type controller that was mounted on the side of the cooler box, where the fan and the rotating equipment is. So upon investigating why the fluctuation in the temperature control, the vibration from the rotating equipment had caused these temperature controls to fail.

The remediation or the change that we made -- these cooler boxes are very complex. Not only that, it has a VFD. The fan is controlled by VFD. So you've got five or six things going on simultaneously that you're trying to control this temperature within a span of 10 to 20 degrees there.

We removed the controller off the cooler box, installed a thermocouple so that we could get this temperature from that location where the controller was installed. We took that thermocouple reading back to a programmable logic controller, as Mr. Torrico talked about briefly, to where you could set these parameters up where it would alarm should you have any -- and get much tighter controls around the operating louvers. When maybe you needed a little more coolant here, it got a signal from the VFD to speed up or slow down a fan.

So it's very complex around the control for that. So that's how we come to the conclusion of changing it.

Q. Based on these remediative steps, these actions you took, have you seen improvements in the temperature controls? Has that resulted in a viable solution?

A. Absolutely. It's a much tighter band now. During injection, the temperature runs from 110, 115, to 125, where we were seeing fluctuations, you know, of 60, 70, maybe even 80 degrees Delta T.

Q. So based on your correction of the thermal controls, how do you know that the temperature controls are working? It sounds like you've got some sort of readout or record on a daily basis of these temperatures.

A. Correct. As brought up earlier, we have a distributive control center. And what that does is this data is periodically scanning for a period of two or three seconds, 15 seconds, whatever those parameters are set up for, to collect this data in a large database.

You turn around, and the POC can be programmed to the DCS. The DCS can even be enhanced with more programming to alert these parameters, either to tighten or widen, whatever design you want, whether it be temperature, pressure, flow, Delta P, Delta T.

And you do similar to what was discussed around these parameters and set up alarms. You can set up two or three different levels of alarms. You can get a minor, a major, you know, Level 1, 2, 3. So that way, you're continuously monitoring whatever you want to or whatever the design is intended.

Q. Based on the current design now, the way the AGI Number 1 is working, it would be a fairly simple matter to coordinate with the District Office and the Division to come up with some parameters, depending on the conditions; is that correct?

A. Oh, yeah.

Q. On that issue, as the Division has indicated, it would like to see some conditions included on the approval of this application. Have you had a chance to review those?

A. Correct. I believe there was six dot points there. One, 2, 4, 5 and 6 we agreed with.

Number 3 is around the parameters. I think that the MIT, you know, will take care of that. That's kind of the proof in the pudding there, around the integrity of that well.

So I think that -- not that -- you know, we're doing that as we did when we went into the agreed order in January. You know, we provided that data on a weekly basis up to that point for review, not only internally, but with the Division, as well.

Q. So you've had no problem doing an MIT every six months with the AGI?

A. No. To be honest with you, you know, six months I think would be better than the parameter dot 3.

Q. On that point, just to be clear, your understanding is that what the Division would like is to have some dialogue between itself and the DCP to come up with what those parameters should be. But the problem that you might have, as an operations person, is that those conditions might change and those parameters might have to be adjusted; is that correct?

A. That's correct. You know, processing facilities, they're always changing, not necessarily the flow or -- you know, as discussed earlier, just the temperature, ambient temperature, can make something change. You know, a 100-degree day versus a 20-degree morning, that we seen this morning, can have a large effect just on operations day in and day out.

Q. So your understanding of what the Division has proposed, and the Division will clarify this, of course, is that there would be that dialogue?

A. Correct.

Q. You wouldn't necessarily be locked in on any given parameter, but it would be a dialogue with the Division about what those parameters should be --

A. Correct.

Q. -- based on the changing conditions of the injection reservoir and the other considerations?

A. Correct. You know, as Mr. Gutierrez mentioned earlier, that reservoir, you know, we're injecting 14-, 1,500 pounds. I would hate to be locked into something.

You know, say 15 years from now, if that pressure goes up to 18 or 19, we already have a pressure limitation of 2,644 to begin with, you know. So as long as we're operating within those parameters and don't exceed that, I feel that that's where we need to go to see some fluctuations from an operational standpoint.

Q. So to maintain that flexibility is the key?

A. Correct.

Q. And the idea that the parameters would be set between -- based on what the Division would like to see, and that it would be a matter of notifying the Division when those parameters are exceeded, and that would trigger a consultation to decide if there are any additional steps that need to be taken, is that your understanding?

A. Correct.

Q. And that's what you'd like to see if these conditions are imposed; is that correct?

A. Correct.

MR. RANKIN: Nothing further, Madam Chair. Thank you. I pass the witness.

CHAIRMAN BAILEY: Mr. Gerholt, any cross-examination?

MS. GERHOLT: Thank you. I do have a few questions.

CROSS-EXAMINATION

BY MS. GERHOLT:

Good afternoon, Mr. Boatenhamer. How are you doing?

A. Fine.

Q. Good.

What's a louver?

A. A louver is -- it's a control device, very similar like to your air conditioner in your vehicle, where you make the adjustment to open or close the vents. It's very similar, just on a much larger scale, where they open or close, either restrict or increase air flow across a certain area.

Q. What is VFD?

A. VFD is Variable Frequency Drive. What it is, it's a way to control electric motors on Hertz, whether you can increase the speed or decrease the speed around a controller.

You know, say you're trying to set a parameter -- I'll give an example. I want to get to a temperature. I want to get at 100 degrees. Maybe I'm seeing 99 or 95, and I want to get to that 100 degrees. I need that cooler fan to slow down just a little bit so I can try to dial that 100 degrees in to achieve whatever it may be in the process that I'm trying to achieve.

Q. So that would relate to controlling of the temperature?

A. Yes.

Q. You mentioned, when you were discussing moving the well, about the perimeter monitor at the well site.

What is the perimeter monitor?

A. At the well site there are perimeter monitors and interior monitors around the equipment. There's a total of 33 at the AGI well site located north of the Linam Ranch facility. The ones on the perimeter are just exactly that, around the fence line.

Q. And is that the bounds of DCP's property around the well site? Is the fence the outer bounds, or is there still more property around that?

A. No. We own or lease the whole quarter section there. The perimeter monitors are on the inside of the fence, the fenced in area, which is less than that quarter section.

Q. You also were speaking about this data that's collected approximately every 15 seconds or so. How long does DCP keep that data for?

A. It goes into what we call a historian. We know from the deal where we gathered the data up for Mr. Gutierrez for evaluation around the well that that went back to April of 2010. What had happened in -- we tried to go back to December of 2009. What had happened, we had an upgrade in the distributive control services or --

MR. TORRICO: System.

A. -- system there, and that's as far as we could go back. We have data back to there. And in some instances, more, because we take daily logs, which some of these parameters that are tracked in the DCS are taken down on a four-hour basis.

Q. This data may not necessarily be kept for a set period of time? It's not every five years, and then there's data dump and then another?

A. No.

Q. Okay. Mr. Boatenhamer, do you have the Oil Conservation Division's Prehearing Statement in front of you?

A. No, I don't.

MS. GERHOLT: May I approach or --

CHAIRMAN BAILEY: YES.

MS. GERHOLT: Thank you very much.

Q. (By Ms. Gerholt) Drawing your attention to page 2 of the Division's Prehearing Statement, Point 4, the first point talking about DCP working with the Division in setting immediate notification parameters, do you see that point?

A. Number 4? Yes.

Q. The Division has listed annulus pressure and tubing and casing differential pressure at a set injection temperature.

Do you have any suggestions for any other aspects that should be identified for notification parameters?

A. You know, it's kind of like Mr. Gutierrez talked about earlier. You look at the Delta P across the injection, the injection pressure and the annular pressure, as well.

You know, it's kind of like early this morning the comment was made that more data is better. The more data you can have, the better you can do to take a look at whatever may surface. So that's the only thing that can come to mind right now.

If I recall, under the agreed order that we had in January of 2012, there was a period in there that talked about the Delta P between the annular space and the injection pressure that there was a requirement to be notified immediately if we reached that 100 degrees Delta P, if I remember correctly.

Q. Did you find that to be a workable condition?

A. We did.

MS. GERHOLT: Madam Chair, I have no further questions for this witness.

CHAIRMAN BAILEY: Mr. Alvidrez?

MR. ALVIDREZ: Yes, Madam Chair. I have a few questions.

Good afternoon, Mr. Boatenhamer.

THE WITNESS: Good afternoon.

CROSS-EXAMINATION

BY MR. ALVIDREZ:

Q. Do you have an understanding about whether DCP intends to increase the throughput at the Linam gas plant after it installs the second well, if it is granted that authority?

A. Currently, no. The maximum throughput is 225. 225 million has been mentioned today. The acid gas injection volume right now can fluctuate anywhere from three and a half up to five and a half million, depending on the amount of CO_2 and H_2S entering the facility from the different strings.

One thing that is unique about Linam Ranch is it has five separate inlets that come in, so that the gas composition could fluctuate a little bit. And we're seeing that, and most of it is with the increase of CO_2.

Q. In terms of the operations at -- let me back up. When did you become manager out there?

A. It would have been mid-December of 2011.

Q. So you've been there about a year as the manager?

A. Correct.

Q. As I understand it, you worked there for a number of years before that. During what period of time were you at the Linam gas plant?

A. I started in January of 2001 and went to the Eunice plant in 2007.

Q. I guess you didn't come back to the Linam plant until 2011?

A. Correct.

Q. Did you have any involvement with the operation of the Linam plant in that 2007 to 2011 time frame?

A. No, sir.

Q. Now, when you were at the Linam plant, I guess it was using the SRU for a period of time; is that correct?

A. That's correct.

Q. What's your understanding as to why the SRU was taken out of service at the plant?

A. As it's been mentioned, acid gas removal is a process in natural gas processing, so you have to dispose of the acid gas one way or the other.

At that time, the technology -- SRUs were the only technology, for the most part. Acid gas injection had just come on the scene over the last 10, 15 years. And to reduce emissions, as well, you're emitting something through the SRU at all times. Through acid gas injection, you're replacing that TAG back into the reservoir that it come out of somewhere through the processing.

Q. Was continuing to operate with an SRU at Linam an option?

A. I don't think so. Over a period of time, it was one or two issues. From an environmental standpoint, the AGI was the better option.

Q. Wasn't there a consent order with the New Mexico Environment Department requiring you to discontinue use of the SRU?

A. Under the settlement agreement, yes.

Q. I guess that necessitated the use of the acid gas injection well; correct?

A. Correct.

Q. In terms of your overall responsibilities, it sounded to me as though you had oversight with respect to all of the plant operations. And I take it that that would include compliance issues?

A. Correct.

Q. With regard to compliance issues and air emissions from the Linam plant, was the plant cited by the New Mexico Environment Department for air emission violations in the October time frame of this year?

A. Under the -- I guess I don't quite understand as far as "cited."

Q. You hadn't received a Notice of Violation and had to play a penalty?

A. Under the settlement agreement order with the NMED, there are stipulated penalties that occur through that. As far as Notice of Violation, I refer to those as -- under the agreement as stipulated penalties.

Q. Were stipulated penalties imposed under that consent order with the New Mexico Environmental Department in October of this year?

A. Correct. There's a quarterly review.

Q. What stipulations were violated that caused the penalties to be incurred?

A. There are a number of things. There's four major ones, or major -- there is third-party events. The way the settlement agreement is wrote up, there's equipment malfunctions. There could be a force majeure event, and there could be an operator error event.

Depending on the way the settlement agreement works is depending on the pounds of emissions emitted into the atmosphere, it depends on who reviews that. Anything under 500 pounds is a third-party company that comes in and reviews that event. Anything over 500 pounds, it's reviewed internally. All those reviews are sent to the NMED after the review and the investigation has been completed.

So does that answer your question?

Q. It helps.

What I'd like to do is show you what we've marked as Smith Exhibit 2. And I don't know if you have our Prehearing Statement with you at the desk. If you don't, I do have the exhibit.

MR. ALVIDREZ: Ma'am Commissioner, I have extra copies for the board members that don't have a folder.

CHAIRMAN BAILEY: We appear to have some.

MR. ALVIDREZ: Very good.

Q. (By Mr. Alvidrez) All I'm going to ask you to focus on, Mr. Boatenhamer, is really the first page of Smith Exhibit -- actually the first two pages of Smith Exhibit 2, and ask if you recall having the facility pay or DCP pay a stipulated penalty fee of $27,500.

A. For the month of October -- for the third quarter of 2012, yes, sir.

Q. That period was just limited to the third quarter of 2012?

A. Correct.

Q. What is your understanding of the bases for the stipulated penalties that were assessed?

A. If I recall, it was three events, possibly. It had to do with the lube oil cylinder, lube oil, on

1410.

Q. What is 1410?

A. Acid gas injection compressor.

Q. And what were the events involving Compressor 1410?

A. I don't have those in front of me. They were -- one was around having air in a lubrication line, I believe. I don't have the detailed report in front of me, so I hate to give you something that I don't have in front of me.

Q. So you don't have a recollection of what the issues were?

A. No.

Q. Let me ask you this: Were any of these penalties assessed for any air emissions in excess of permitted amounts?

A. Under the settlement agreement, yes.

Q. And what were the air emissions that were -- what were the air emissions?

A. When you have a flared event, the result is an air emission. Depending on what source that comes from, that could be a number of different things. I mean the natural gas stream to methane, ethane, propane; depending on where the process is, SO2, CO2. So I mean that's --

Q. Is every flare event a violation of the stipulation that you have with the New Mexico Environmental Department?

A. No.

Q. Do you have -- are you allowed to have a specified number or duration of flare events before you violate the stipulation?

A. There is what they call maintenance startup and shutdown emissions that are allowed; some third-party events, force majeure events, things that DCP has no control over.

Q. As I understand the penalties that we're talking about here in Exhibit 2, these were all as a result of errors by plant personnel? That's how they were classified; is that correct?

Take a look at page 1 of Exhibit 2.

A. Okay. Correct, that's what they're classified as.

Q. And were any of these events for which DCP paid stipulated penalties related to emissions of H2S?

A. No. There's H2S in an acid gas stream, along with -- you know, the H2S is converted to SO2 through fuel assist when there is a flare event.

Q. What protocols, if any, have you put in place to correct these errors by plant personnel?

A. We continue to work on training, you know, day in, day out. There are some read-up sheets. We have put in more frequent monitoring of what -- not knowing and seeing what these exactly are, but typically that's what we do when we investigate these and find something that would come around as an error of a plant personnel.

MR. ALVIDREZ: Madam Chair, I would move the admission of really just the first two pages of Smith Exhibit 2 into evidence.

CHAIRMAN BAILEY: Any objection?

MR. RANKIN: Madam Chair, I would just object to the admission of the other parts, the parts that are unrelated to the Linam Ranch. For example, the Eunice and Artesia plants, I would ask that those be removed from the exhibit.

MR. ALVIDREZ: I'm not moving those. Certainly they can be discarded.

CHAIRMAN BAILEY: So only the first two pages?

MR. ALVIDREZ: Just the first two pages is all I'm asking to be admitted into the record.

MR. RANKIN: That's fine.

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: Then they are admitted.

(Smith Exhibit 2 was admitted, as amended.)

MR. ALVIDREZ: Thank you.

Q. (By Mr. Alvidrez) With regard to the Linam plant, have there been operational difficulties associated with the acid gas injection well? Apart from what we've been talking about today, have there been other issues with the operation of the AGI Number 1?

A. It's like anything else. Through the process, there's multiple -- there's transmitters, there's thermocouples, there's a ton of wire. I wouldn't say anything out of the ordinary.

You know, the temperature control issue that we've already discussed, there is some programming that we have corrected and that you find through some of these investigations, whether they be internally or third party, that we correct.

Q. We have talked about some of the operational parameters that are being recorded. Temperature and pressure are a couple of the ones that received the most attention in this hearing. And there's been some discussion about whether it's appropriate to have DCP submit monthly reports to the Division with respect to some of these operational parameters.

But let me ask, in terms of the data that's collected in these operational parameters, is there anyone whose job it is, aside from Mr. Gutierrez, present to review the data and try and analyze how the system is operating?

A. Yes, sir.

Q. Who is that?

A. Jonas Figueroa looks at that data, as well.

Q. Who is Mr. Figueroa?

A. An engineer.

Q. Is he at the Linam plant?

A. He's out of the Midland office.

Q. What are the parameters that you're monitoring right now relative to the issues that we've been talking about and the efforts to try and decrease the chances for corrosion in the tubing?

A. We look at injection pressure, annular or back side pressure, injection temperature and flow rate.

Q. I take it this is data that's logged and maintained, and it's not particularly burdensome to package up this data and send it in once a month to the Division?

A. It is. It takes about six hours to download that. As I mentioned earlier, out of the historian, we have to go in there and download that, and that's placed into a spreadsheet. We do that on a weekly basis, review that, which we did from January until the well workover.

Now we still continue to gather that data internally. I see that data on a weekly basis, and my

I&E tech, and then that's shipped to Jonas Figueroa. And on a monthly basis, it comes back to Mr. Gutierrez. So internally, we look at that.

Q. Did you go back and look at any of the historical data from plant operations up until the time the plant failed the test in December of 2011?

A. Yes, we did.

Q. I'm talking about you, personally.

A. No. At that time, that was about the time I got down there, around that MIT.

Q. So perfect timing?

A. So we relied -- I was involved in some of the discussions with Mr. Gutierrez, as well as internally with Mr. Jamerson and Mr. Figueroa.

Q. With regard to the April workover that took place on the AGI Number 1, were with you involved in that?

A. At that time, Mr. Jamerson was the person that was overseeing that well work for DCP Midstream.

Q. Were you primarily working at the plant?

A. I was at the plant, yes.

Q. In terms of the period of time before the workover and while the plant was operating, what were the pressures that were typically being injected into AGI Number 1?

A. You know, depending on the volume, anywhere from 1,000 to 12-, 1,400. They fluctuated.

Q. And after the workover, what are the typical operating injection pressure?

A. The typical injection pressure right now runs about 1,450 to 1,500 pounds.

Q. Did you have any notice or involvement of the release of acid gas that happened in April, during the workover?

A. Correct. After that release, I was at the site. That afternoon is when Mr. Jamerson come and said that they had a burp and the wind up, putting the temporary flare out.

Q. In terms -- well, what I was trying to find out is, were you at the well site when that happened, or were you off at the plant?

A. No. I was at the plant.

Q. Did you undertake any efforts to notify the Smiths that you were working on this well and there might be a potential for release of acid gas?

A. No, I personally did not.

Q. Do you know whether DCP took any actions to notify them?

A. I don't know. Like I said, Mr. Jamerson was in charge of that well workover at that time, and I'm not -- I don't know whether he did or not, sir.

Q. Were you the one that raised the issue about the proposed original location for the AGI Number 2 well being downwind from the existing well?

A. Correct.

Q. In terms of where the Smiths' property is located and their related buildings, is that also downwind from the well, the prevailing winds?

A. No. The Smiths' barn and trailer are back to the west and north of the existing AGI Well Number 1.

Q. Does DCP keep any record about when people call in about concerns about plant operations or well operations?

A. Yes, sir.

Q. Do you know whether the numbers that DCP has put out for notification purposes, whether those numbers -- telephone numbers I'm talking about -- whether those are still operational?

A. The numbers for control rooms and offices are still operational, yes, sir.

Q. With regard to these flare events that occur, are there any liquids that are flared off along with the gas?

A. No.

Q. Do you utilize a personal H2S monitor?

A. Yes.

Q. You keep one with you while you're at the plant?

A. Yes, sir.

Q. Is that something that's required of all personnel?

A. Yes, sir.

Q. Do you also have, I guess, portable instrumentation that can take readings of H2S levels?

A. Yes, sir.

MR. ALVIDREZ: Thank you very much.

CHAIRMAN BAILEY: Commissioner Warnell, do you have any questions?

COMMISSIONER WARNELL: I do.

EXAMINATION

BY COMMISSIONER WARNELL:

Q. The pipeline that goes from the plant to the well site --

A. Yes, sir.

Q. -- is that a north/south?

A. It's north/south. And right before it gets to the facility, it makes a dog leg back in the northwestern direction into the perimeter of the AGI well site.

Q. Okay. Would I be able to see that on Google Earth, do you think?

A. Yes, sir.
Q. The SRU -- I'm curious. The capacity of the SRU when it was operational, was it able to handle as much acid gas as the existing Number 1 well?
A. Probably through that -- my recollection is that it was about five, five and a half million, is what the design of that SRU was.
Q. It was kind of more or less the same?
A. Correct.
Q. I just wanted to clarify. You were flaring an acid gas stream in the third quarter of 2012?
A. Correct. There has been periodically.
Q. And it was pointed out that the violations that were cited were personnel errors?
A. Correct.
Q. You mentioned that there's more training being put in place?
A. Correct.
Q. Who's handling that training? Who does that?
A. We have a training department in Southern New Mexico that is focusing on that. There's a lot of different options. We've brought individuals in when we find something that -- you know, that we uncovered through one of these investigations, whether it be a third party to train around calibration, temperature

controls, operation of lubricators, programming VFDs. There's just a multitude -- these facilities are complex, so there's just a multitude of these things that we could relate to when you talk about training.

Q. The plant itself -- and I refer to it as the well site. Do you call it a well site, the perimeter that's around the well, as it exists today?

A. That's the AGI well site.

Q. What kind of personnel are down at the plant, number-wise, at any given time, versus at the AGI well site?

A. There are two people on shift at the Linam Ranch facility in a 24-hour period. One thing that we have evaluated, and we just recently hired an increased head count, is to go to a three-man shift for better coverage around the Linam Ranch and the AGI well site.

Q. At the plant, there's how many people there right now?

A. There's two operators.

Q. Normally, you would be there? Is that where you spend the bulk of your day?

A. Correct, whether it be there or the AGI. Now, if you're talking about occupation, our I&Es office out of the Linam Ranch plant. Our mechanics office out of there. Our field operators office out of there. Some of our engineering and support staff operate out of that office, as well.

Q. Up at the well site, is there anybody there right now?

A. It depends if they're making their rounds at 5:30.

Q. There isn't like an office there?

A. No, there is no office. There's nothing occupied at the well site.

COMMISSIONER WARNELL: Thank you. That's all I have.

CHAIRMAN BAILEY: Commissioner Balch?

THE COURT REPORTER: Can I take a brief break?

CHAIRMAN BAILEY: Yes. We'll take a 10-minute break.

(A recess was taken.)

CHAIRMAN BAILEY: Back on the record.

Dr. Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. Good afternoon, Mr. Boatenhamer.

Plant operators, for clarification, that's the person that sits with the control panels, watches things for alarms or reacts to things or makes little adjustments to the process?

A. Correct, it can be. Or they can be out in the facility, as well.

Q. I keep going back to temperature, because Mr. Gutierrez indicated it was a very sensitive part of the process.

I want to talk a little bit about the temperature of the gas that's coming in versus the temperature that's coming out. Is the temperature of the TAG related to the process or related to what's coming in?

A. The temperature of the TAG is -- going into the well, where we had the temperature issues, is related to the compression. There's four stages of compression. So specific to that, that's where that is.

Q. The outlet for the plant and the pipeline from the plant to the AGI site, that temperature is less relevant than the compression process?

A. Correct.

Q. That's what produces your temperature?

A. Correct.

Q. I believe Mr. Gutierrez indicated that that pipeline from the compressor to the wellhead was insulated?

A. Correct, from the AGI well compressor.

Q. Where does the variability in temperature come in from the compressor? Is that through a throughput?

A. Through your different phases, through your four stages of compression.

Q. If you're running less gas or more gas, that can cause a temperature variation over time?

A. Correct, and through the complex cooler box that each one of those stages go through in cooling.

Q. So really, the only variability is the amount of TAG that's going through the compressors and then the amount of cooling that's needed to get it to the right temperature?

A. Correct.

Q. That's fairly well insulated from the outside environment? If it's 10 degree at night or 100 degrees degree in the day --

A. You still have ambient temperature effects, even though it's insulated. The insulation is 3 to 4 inches thick, covered in metal insulation. But the ambient temperature can still affect that around that 200-, 250-foot distance there from the discharge of the acid gas compressor to the wellhead.

Q. So what's the kind of average temperature coming out of the compressor? How much cooling do you have to apply to the gas?

A. There again, it depends on the flow rate. The average, depending on the controls of the louvers and the VFD, you're coming out of the fourth stage at 157 degrees, I believe. I think.

Q. And your target is 115, 120?

A. 115 to 125.

Q. As low as -- I think 100 would be okay?

A. We get -- you know, when you get down below 100, we start getting concerned.

Q. That's where condensation comes in?

A. Yes.

Q. The temperature control is all automated? It's not part of the control process for the Linam plant?

A. Correct.

Q. That can be remotely controlled and dynamically change louvers and all that stuff to adjust --

A. Correct. On that specific, you have to be at the well site. You can monitor that data from the control room, but you can't change those parameters from the DCS.

Q. What's the reaction time for -- say your temperature drops to 90. How fast can someone go and adjust the louvers?

A. It's about five minutes over there.

Q. Is that something that a plant operator would do, or would you call a mechanic?

A. What would happen in that situation, if you see that drop in temperature, the inside plant operator that's on the control board would make that call to the operator out in the facility. "Hey, your temperature, your acid gas temperature, is 90 degrees. We need to go take a look at it."

He would go to the well site and take a look at it. They monitor those on their rounds, when they make their rounds to the well site. You know, depending on everything that's going on, they make at least three to four rounds a day per shift through that well site.

Q. So you've got someone there actually every two hours or so?

A. Give or take. That could -- something in the facility -- you know, there's many processes in the natural gas process. If they got tied up with another issue at the plant, it may not be right at two hours when they got back over there, as long as the inside operator is monitoring the parameters and can see that at all times.

Q. We were taking about data availability. There were some questions about how far back you can go. You indicated that you had a change through your DCP system that caused a loss of about five or six months' worth of data. Is that data actually lost, or just not processable through your current system?

A. I think the data that we have on our four-hour reports, which is some of that that we take anyway, is they would be able to retain what they did when the distributive control center -- when they upgraded that.

The third party involved in upgrading that had a malfunction and lost data, actually, I'd say, back to 2009. Data probably all the way back to 2003 or so, the historian keeps that.

Q. In response to that, have you changed your archival system at all? Do you have on-site backup or off-site backup?

A. We have several different options now. We run two local external hard drives that download that. And then the third-party company that services that DCS system has access to get in and download that and keep that data, as well.

Q. So it's very unlikely you would lose data like that again?

A. Correct.

Q. Before we go down to the penalty question, do you think that the AGI Number 2 or a redundant well there would reduce air quality related penalties, or there --

A. I do.

Q. -- would be less of a chance?

A. What it would do is we would be -- as we had the issue with AGI Number 1, even in that planned, controlled environment to take that facility down, it takes a lot of individuals involved in getting that gas off the system systematically.

So if we had that, you wouldn't have that 24-hour period of maybe intermittent or up or down, maybe where somebody didn't respond to get gas off the system. The flares are a protection device, you know, so that's what you would do in that circumstance. So from that standpoint, yes, it would reduce emissions.

Q. For an unexpected shutdown -- I think it was mentioned you have a thousand wells coming into your system?

A. Correct.

Q. Does that require someone to go to each one of those well sites and shut off a valve?

A. Yes, sir.

Q. How much response time do they have?

A. Historically, in an unplanned event, we've seen up to taking 72 hours to get those wells off the system.

Q. What happens if your plant stops taking gas and there's a delay before they shut off their well?

A. If we quit taking gas and the producers haven't responded by shutting that gas in, you've got several issues, safety, environmental issues. You have the possibility of overpressuring pipes, pipe ruptures. You could have a liquid release. If that gas is sour gas, you could have an H2S release. There's just a number of things associated with that. Vents and flares in an uncontrolled environment across the counties, mainly in Eddy and Lea County.

Q. Operators don't like to shut in their wells, either?

A. No, sir.

Q. That can damage --

A. That can damage their wells. A lot of times some of them will water them in, and they have to come back and --

Q. So you've worked at a couple of these plants?

A. Yes, sir.

Q. Normally, there's some sort of redundancy in most steps of the process?

A. Correct.

Q. You have plants in Artesia and Hobbs, as well?

A. We do have a facility --

Q. Eunice?

A. Eunice, Artesia. The Hobbs plant is in the same vicinity.

Q. They have a redundancy system for dealing with the TAG?

A. Hobbs plant is a sweet gas facility.

Q. They just vent the CO_2?

A. There is no treating at Hobbs. It's a sweet gas facility.

Q. No CO_2 --

A. No CO_2 or H_2S.

Q. -- or H_2S? What about the other plants?

A. The Eunice plant has no redundancy. We still operate an SRU at that facility.

Q. No injection, just SRU?

A. Yes, sir.

Q. Penalties, you said these were quarterly. They compile these quarterly and send you a bill?

A. Correct. We do -- through the settlement agreement that we entered into in 2008, there's a lengthy process through that. We investigate every flared event, whether it's -- you know, to better serve, to try to reduce those. You know, to get a better understanding.

We found a lot of things where we can do better. And we found things where -- maybe force majeure, third-party situations, that will help. We all learned from that. And the main purpose of that is to reduce the emissions and to increase the safety.

Q. So on a quarterly basis -- I know that only the Linam Ranch was put into evidence, but each facility will have a record of violations that result in a penalty?

A. Correct.

Q. Is this like a typical quarter, a bad quarter?

A. If you look at that exhibit there, that's a bad quarter. You have two events there that are over $10,000 apiece. Through the settlement agreement, depending on the amount of the volume flared and the tonnage it comes out to is where the agreement solidifies what that penalty will be.

If you'll notice, there's one there for $1,000. There's also one for $4,500. So all those requirements are in the settlement agreement.

Q. These are errors by plant personnel that result in an emission?

A. Correct.

Q. Was that the cause of the violation?

A. Correct. When we look at that, we err on the side -- if there's something borderline, a mechanical failure possibly, DCP is going to err on the side of their operator before that in going through some of those investigations.

Q. What would be a typical error by a plant personnel that would lead to a release? What's the most common thing?

A. I think, given in that exhibit, there's one there were we had air in the lubrication system for the AGI compressor.

Q. You had to shut down the compressor?

A. What happens is you don't get lubrication to your compressor cylinders. That's a safety device to keep from tearing up equipment to shut that down.

I think, looking and reviewing that, they had bled the air down on that one and thought they had it. They started it back up and turned around, and it still had some more air in it, and they shut it down at that time.

Q. These are things that you log at your plant and report, and someone comes by and looks at those reports on a quarterly basis?

A. Yes. It's self-reporting. Through the settlement agreement, from the date of initiation, depending on the pounds, anything under 500 pounds on an event is investigated through a third party, and we have 15 days to submit that report to the NMED.

Anything over 500 pounds is investigated internally, and we have 30 days to send that report to the NMED. There's also stipulated penalties if you exceed the requirements in that settlement agreement as well.

Q. Thank you.

A. We're very prudent about doing those.

Q. In a typical quarter, what would be an average number of violations?

A. I've seen a quarter where we haven't had any violations. I've seen a quarter where we have seven or eight violations. It just depends.

Probably going back and looking at the average of it, you might have two, maybe three, on average.

Q. So this was for the third quarter of 2012. Do you recall how many were in the second quarter?

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

COMMISSIONER BALCH: Those are my questions. Thank you very much.

THE WITNESS: Thank you.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. You said there were two operators or three at the Linam plant?

A. There's two operators on shift at any given time, yes, Madam Chair.

Q. Which means that you all have 12-hour shifts?
A. Yes. Normal operations is 12-hour shifts, seven days on and seven days off. 5:30 to 5:30 we make shift change.
Q. And so possibly you'll have a third coming on, and that would give you eight-hour shifts?
A. No. We'll put three people on shift. We will still remain on 12-hour shifts and a seven day on/seven day off schedule, but there will be three individuals on at any 24-hour period.
Q. I'm following up on the lead that phone calls have been made to the plant, but no one answered the phone. Do those phone calls go to the two operators?
A. Depending on what number is called. The control room has an operator in there 24 hours a day, seven days a week. Very seldom -- you know, he may step back to the back to look at another panel, but there will be a missed call on the screen. There's answering machines. There's the whole thing there.
So the primary number for the control room, there's actually three numbers for the control room. Now there's a main number for the front office, which is manned Monday through Friday from 7:00 to 3:30.
Q. If someone tries to call that number instead, they're not going to get a response if they're calling at

4:30 in the afternoon?

A. If they call at 4:30 in the afternoon, Madam Chair, that rolls over to the answering service. Then the answering service turns around and will contact -- address that call, you know, for whoever may be calling.

There's a call list of people who have areas of responsibility that is published every Friday. It has all the areas of responsibility across the whole operations of Southeastern New Mexico, from operational personnel to support staff, whether it be environmental, safety, right-of-way or whatever. So that's how that's handled.

Q. When or if the second well is drilled, will there be an additional line from the plant to that second well, or will the existing line that's servicing that first AGI Number 1 be used for the entire amount of TAG?

A. The design now is utilizing the existing line from the Linam Ranch plant to the existing AGI well. That was one reason to move that well, because the way that was laid out benefited the connections coming into that facility if we were granted the option of AGI Number 2.

Q. So a line to AGI Number 2 would be a branch off of the existing line?

A. Correct.

Q. How old is the Linam plant?

A. 1953 is what some of the records date back to.

Q. It's about 60 years old?

A. Correct.

Q. Are any of the underground pipes ever pressure tested for leaks?

A. At some times in our mechanical integrity program, they are. As we have expanded over the years, a bunch of that has been brought above ground to get away from having pipes underground. It's just a more prudent way to complete your inspections, where you're not having to dig nothing up. You eliminate some of the corrosion possibilities for corrosion with buried pipeline.

Q. Which brings up the question of the line from the plant to the AGI Number 1, that you have no plans to include that in the mechanical integrity program?

A. The line from the plant to the Linam AGI Number 1 is constructed very similar, kind of on the same concept as that acid gas injection well itself.

It is a steel pipeline with a poly-type liner that is corrosion inhibiting. It is encased with a larger diameter of pipe with an inert gas, nitrogen, in between the casing and the outer wall of the transport -- what I would call the transportation line. And the pressures between those, that inert gas, is -- we monitor that for any mechanical integrity around the transportation of that line from the facility, the Linam Ranch facility, to the AGI well site.

Q. Do you have annual plant shutdowns in April, as you did last year, for --

A. No. Typically, what we try to do around the maintenance schedule is two to three years. This past April had been planned for some time for the expansion around Linam Ranch. But typically, we try to go two to three years, looking at pushing back.

Along with that, there's numerous mechanical integrity programs that dictate that two- to three-year period. There's been times through those processes when we may have -- something may have surfaced where maybe we're only looking at a year or 16, 17 months.

Q. But if the Number 2 well is approved, you don't have a scheduled shutdown which would interfere between now and that well being put on line?

A. Correct. We don't have a scheduled shut down at this time.

I think -- and maybe that would be a question for Mr. Torrico, about physically tying that in. That was one reason we looked at the location. We had less pipe and different variations there to minimize the amount of tie-ins that would be needed to get Acid Gas

Number 2 in service.

Q. And down time involved?

A. Correct.

CHAIRMAN BAILEY: Those are all the questions I have.

Do you have something else?

COMMISSIONER BALCH: I have follow-up.

FURTHER EXAMINATION

BY COMMISSIONER BALCH:

Q. I just want to be clear in my own mind. The proposed AGI 2 would have its own compression and heat control apparatus, or would it go off of the existing compressor at AGI Number 1?

A. It would go off of the same controls. You would be utilizing the same compressor.

Q. So you would have a compressor, your temperature control, and then you would have a line split from AGI Number 1 to AGI Number 2?

A. Correct.

COMMISSIONER BALCH: Okay.

CHAIRMAN BAILEY: Do you have any redirect?

MR. RANKIN: Madam Chair, I have a couple of questions to make clear a couple of points, if I might.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Boatenhamer, did any of the stipulated penalties identified in Exhibit 2 arise as the result of an H2S release of any kind?

A. No.

Q. Do any of these stipulated penalties referenced in Exhibit 2 have anything to do at all with the operation of the well itself?

A. No, sir.

Q. Can you briefly explain for the Commissioners when a flare might occur at the well, versus the plant site?

A. The way it's designed is off of a pressure control. Through the process, the amine sweetening process, your total acid gas is removed through the amine process. It goes through a closed-loop amine surface process, where we regenerate what we call rich amine. Then we make it back into lean aimee to go back through the sweetening process. The by-product is acid gas. At the end, there's a pressure control valve upstream of the compression at Linam Ranch, as well.

If the well site goes down, the pressure control valve at the Linam Ranch facility opens up, and you flare the acid gas at the Linam Ranch facility. What happens at the well site, as far as a flared event, is what would be considered maintenance, startup and shutdown events.

The fourth stage of that compressor is 14- to 1,500 pounds that's permissible on the PLC, programmable logic control. Upon restart, that fourth stage pressure has to be down to 50 pounds, which is a safety issue.

So therefore, that fourth stage compressor is bled from 1,450 pounds down to 50 pounds before the restart of the compressor. And that's the only thing -- that is one scenario that you would have any flaring at the well site.

The AGI well workover, you know, not only did we work that well over, but we took that opportunity to complete some integrity around the vessels, piping and that kind of stuff. So those had to be vented down. That would be vented through there.

If you had overpressure, you know, PSV or something possibly that went off over there, it would go to that acid gas flare. Outside of that, it's very minimal of what's flared at the acid gas well site.

Q. Another question I want to clarify a little bit: The requirements under the settlement agreement with the NMED. When the Linam plant has an emissions event, is each event evaluated separately?

A. Correct. Total and separate investigations.

Q. It's whether or not one of those four factors caused the event that you identified; is that correct?

A. Correct.

Q. And the only time DCP pays a stipulated penalty is when it's an operator error; is that correct?

A. Correct.

Q. Thank you very much. That's all for that issue.

I wanted to follow up real quickly on the monitors, the H2S monitors on the site. During the April workover event, there was -- can you explain what monitors were in place during the time of that workover?

A. As Mr. Gutierrez explained earlier, Total Safety was the contract company, third-party company, that was in charge of the safety. Very similar to what you would do at a well workover drilling a new well, temporary H2S monitors were located at strategic areas around the facility. So for the well workover, that's the monitors.

Q. And the monitors were Total Safety had well workover monitors near the location of the workover; is that correct?

A. Correct.

Q. And there were also monitors on the perimeter, just inside the fence line?

A. Correct. You have the fixed monitors at the facility.

Q. So the monitors that were triggered by the bubble that came through were the workover monitors near the workover site?

A. Correct.

Q. And then you also, in preparation for this hearing, did a review, did you not, of all the perimeter monitors going back in time?

A. Correct.

Q. Did you identify an emission event that would have triggered the contigency plan on the perimeter monitor?

A. I did not identify anything.

Q. So the release was triggered by the monitor at the workover site itself. But to your knowledge, nothing exceeded the perimeter of the fence line that would have required DCP to initiate the contigency plan; is that correct?

A. That's correct.

Q. But DCP contacted the OCD to notify them of the bubble anyway; is that correct?

A. That's correct.

Q. Is DCP required to notify neighbors under the contigency plan or under Rule 11 if it's going to begin to do work on a workover? Is there any requirement for you to notify anybody in advance that you are doing a workover?

A. Not being familiar with the well workover contigency plan, I don't get called.

Q. If one of the perimeter monitors is triggered at a level that requires notification, DCP would have notified them; is that correct?

A. Correct.

MR. RANKIN: I have no other questions, Madam Chair.

CHAIRMAN BAILEY: All right. Then you may be excused.

It is quitting time. We'll have to reconvene tomorrow morning at 9:00.

You have no other witnesses, do you?

MR. RANKIN: No other witnesses, Madam Chair.

CHAIRMAN BAILEY: Then we will begin with Ms. Gerholt's witnesses.

MS. GERHOLT: Very good.

CHAIRMAN BAILEY: Okay. Then we will see you tomorrow morning at 9:00.

(The hearing was adjourned at 4:45 p.m.)

REPORTER'S CERTIFICATE

I, JACQUELINE R. LUJAN, New Mexico CCR #91, DO HEREBY CERTIFY that on December 20, 2012, proceedings in the above captioned case were taken before me and 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.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with 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.

WITNESS MY HAND this 2nd day of January, 2013.

Jacqueline R. Lujan

Jacqueline R. Lujan, CCR #91
Expires: 12/31/2013