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

ORIGINAL

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

Case No. 14664

APPLICATION OF FRONTIER FIELD SERVICES FOR AUTHORITY TO INJECT, LEA COUNTY NEW MEXICO.

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REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING

BEFORE: WILLIAM V. JONES, Technical Examiner
DAVID K. BROOKS, Legal Examiner

June 23, 2011

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, Technical Examiner, and DAVID K. BROOKS, Legal Examiner, on June 23, 2011, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis, Drive, Room 102, Santa Fe, New Mexico.

REPORTED BY: Irene Delgado, NM CCR 253
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A P P E A R A N C E S

FOR THE APPLICANT:

Gary Larson
218 Montezuma
Santa Fe, NM 87504

I N D E X

EXAMINER JONES: Let's get started with the first case this morning. Let's call Case 14664, application of Frontier Field Services LLC for authority to inject, Lea County, New Mexico. Call for appearances.

MR. LARSON: Good morning, Mr. Examiner. Gary Larson, Frontier Field Services.

EXAMINER JONES: Any other appearances?

(No response.)

MR. LARSON: Would you give us a moment of indulgence to set up the power point presentation?

EXAMINER JONES: Let's take a recess. We'll take at least a five-minute recess. I will go upstairs and get somebody.

(Recess taken.)

EXAMINER JONES: Let's go back on the record.

MR. LARSON: Mr. Examiner, I have two witnesses to present this morning.

EXAMINER JONES: Will the witnesses please stand and state your name.

MR. PRENTISS: John Prentiss.

MR. GUTIERREZ:: Alberto Gutierrez.

EXAMINER JONES: Will the court reporter please swear in the witnesses.

(Witnesses duly sworn.)

JOHN PRENTISS

(Having been sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. LARSON:

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

A. John Prentiss.

Q. And where do you reside, Mr. Prentiss?

A. I reside in Carlsbad, New Mexico.

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

A. Frontier Field Services, the area manager for Southeastern New Mexico, and I have the plant manager responsibilities for the Maljamar Plant.

Q. And what does your area of manager responsibility entail?

A. 30 miles to the west, we have another gas plant, the Empire Gas plant, and I'm the plant manager there.

Q. What is the nature of Frontier Field Services business?

A. We are a midstream business. We gather natural gas and process it.

Q. And who is the owner of Frontier Field Services?

A. The Southern Ute Indian tribe owns us. They set up a company called -- Energy back in 2003, 2002, to go off reservation and buy midstream assets, and they are one of several.

Q. Could you briefly summarize your educational background?

A. I have been working plants for 30 years. I have been at the Maljamar Plant for 24. My previous employer had a pretty extensive program that I was involved in, company-sponsored courses. I do have some college towards a business degree.

Q. And was Conoco your previous employer?

A. Yes.

Q. Will you move to the next slide, please. What is the primary function of the Maljamar Gas Plant?

A. We have about 750 miles of pipeline that gather gas. We bring it to the plant. We separate it, and on three liquids. We then compress it for treating. We use a high pressure treater to remove the acid gases and then prepare it for NJO extraction. We use a turbo expander. It's a cryogenic process to extract.

Q. And what type of field gas is the plant currently accepting?

A. Pretty much everything in our area. It's all sour. There is a little bit of sweet gas, but, you know, most recently most of the Bone Springs and Yeso Paddock is what's been the hot spot, and that's sour gas, about two percent CO2, and that's primarily what we have coming into the plant now.

Q. And who prepared Frontier's application?

A. Geolex.

Q. And did Geolex prepare the application under your direction and supervision?

A. Yes.

Q. Did you also delegate to Geolex the responsibility to provide individual notice of the application of today's hearing?

A. Yes, I did.

Q. Move to the next slide, please. What approval is Frontier requesting in its application?

A. To inject HS, $CO2$, the acid gases into the AGI Well so we will no longer be able to flare it.

Q. Will Frontier be the operator of record for the proposed AGI Injection Well?

A. Yes, we will.

Q. Are you aware that Frontier's application identifies a primary injection zone in the Lower Wolfcamp and two secondary injection zones in the Lower Leonard?

A. Yes.

Q. And is Frontier requesting authority to inject in all three of those zones?

A. Yes, we are.

Q. And could you identify Frontier Exhibit Number 1?

A. Yes. This is Exhibit Number 1, it's a plot plan of our facility, kind of a general layout and shows all the fixed equipment, the compressors, the process equipment, our building. North is to the left side of the page, shows -- also shows the area in which our acid gas flares to the east corner in the middle of the page.

Q. Does Exhibit 1 accurately depict the plot plan of the Maljamar Plant?

A. Yes, it does.

Q. And referring to Exhibit 1, would you briefly describe the process Frontier employs to process sour gas?

A. We gather the gas, bring it in the plant. We have a high pressure amine treater, so we have to get it up to about 900 pounds, and then we run it through an amine solution. We currently use a DEA amine to absorb the H2S CO2 gas spring. That rich amine is then sent to a process where it's regenerated and heat used to drive off the acid gases. Those acid gases are then cooled and the water is condensed and gases go out to our H2S flare where it's burned and converted to SO2.

Q. So presently all of the H2S and CO2 that's extracted from the amine unit is flared?

A. Yes.

Q. Move to the next slide, please. Can you point out with a pointer where the flare is located?

A. Yes. There it is, okay. This yellow square right here is the pad in which our H2S flare is currently located, about right there just to the east of the pad, the acid gas comes off of a header over here in the plant. It's underground, comes up over into this location where we have a separator, and then it goes to our flare stack.

Q. And who owns the surface where the plant itself is located?

A. Frontier Field Services owns it. It's a deeded lot.

Q. Okay. And how about the location where the flare is?

A. The flare is on a lease property, BLM.

Q. And above that there -- it shows an existing BLM easement. Is that for the pipeline?

A. Yes. The right-of-way for the pipeline, that is correct.

Q. And if you could, point out where the proposed well was.

A. Right here, just to the -- to the south, a little to the east of where the flare stack is is where the proposed well is staked.

Q. And is that outside the current leased area where the flare is?

A. It is.

Q. And does Frontier have any discussions with the BLM about expanding that lease?

A. Yes. Our pipeline foreman and landman have gone to the BLM. We have done the arc study and prepared everything they have requested. They kind of gave us a verbal, but held it up until the permitting process for the well is completed. They want us to have the permit in hand before they issue our lease. We are going to lease that whole -- that shaded area is about a five-acre area. We are just going to lease that whole area so that we will have the facilities for the compression and the dehydration.

Q. And will there be a new pipeline installed for the AGI Well?

A. There will. What our plans are is to tee off of the, before the gas goes to the flare stack, tee off, go over to the section of the compressor which will be in this area, and discharge of compressor will go to a dehy system and then over to the wells. So we're not talking about, you know, this is a five-acre plot, so it's a pretty short discharge line.

Q. And does Frontier currently have a permit or permits issued by the Air Quality Bureau of NMED?

A. Yes. Maljamar is a Title V facility. It also has an NSR permit.

Q. And are there maximum emission rates in those two permits?

A. There is. We are limited right now in five tons of SO_2 for our amine system. The plant has a permitted volume of 60 million, but we are hitting the 4.9, 4.8 tons of SO_2 at about 54 inlet, so we've got about 6 million capacity range that we can't hit because of the H_2S content.

Q. And because of the emission rate limitations --

A. Exactly.

Q. -- of permits? Would you move to the next slide, please. In relation to the fluid to be injected, what percentage of the fluid will be CO_2?

A. CO_2 is about 88 percent.

Q. What percentage is H_2S?

A. H_2S is about 12 percent.

Q. If Frontier's application is approved, will the flare still have an operational function?

A. Yes. We are going to approach the Air Quality Bureau to permit it as an emergency flare to kind of, you know, any maintenance-related issues with the compressor, there will be some down time, things like that, we'll try to permit it as an emergency flare so we can keep the plant on line.

Q. So other than those emergency situations or plant-maintenance situations, you will no longer be flaring any CO_2 or H_2S?

A. Correct.

Q. Will the injection allow Frontier to process more sour gas?

A. Yes, it will.

Q. And how much more?

A. Well, this is a first puzzle or piece of a puzzle in an expansion project. At our current 60 million volume, we could go to the 60 million. Our intentions are to then -- to plant expansion. We have had several producers approach us and basically ask us what is it we are doing. This time next year, two of the producers are going to have about 90 million cubic feet of gas available this time next year over and above what they have today, so this is the first step in doing a plant expansion.

Q. And do you have any idea at this point in time what the expansion will entail in terms of increased capacity?

A. We are looking at putting in 50 million a day expansion.

Q. And would that expansion require a new application for injection authority?

A. No. No. We are -- we've got the volumes in this permit that would take into account the expansion.

Q. And I next ask you to identify Exhibit Number 2.

A. Exhibit Number 2 is a letter that we drafted up to Mr. Sanchez. We had received a letter basically stating that we didn't have an H2S Contingency Plan in place, and we needed to respond. And this is in response, and this letter basically states that we did have a plan in place. It was submitted 2004-2005, and that's -- that's what the letter basically states.

Q. And on Page 2, is that your signature?

A. Yes, it is.

Q. And is this Exhibit 2 a true and correct copy of your letter to Mr. Sanchez?

A. Yes, it is.

Q. And in your letter did you inform Mr. Sanchez that you would be submitting an updated plan to comply with Division Rule 11?

A. Yes.

Q. Could you identify Exhibit Number 3?

A. Yes. This letter, Exhibit Number 3, is a letter in response to taking the old plan, the Rule 18 or 118 and making sure it complied with the Rule 11. And so we did that, and the letter basically states that we -- we have updated it and we have attached a copy of the plan.

Q. That's the current H2S Plan?

A. That's the current H2S Plan.

Q. Are the letter and H2S Plan comprising Exhibit 3 true and correct copies of those documents?

A. Yes.

Q. Do you have personal knowledge of the matters addressed in the current H2S Contingency Plan?

A. I do.

Q. That's in your role as plant manager?

A. Yes.

Q. And, to the best of your knowledge, does the current plan satisfy the requirements of Division Rule 11?

A. Yes, it does.

Q. And does the plan, as it exists today, include the proposed AGI Well?

A. It does not.

Q. If Frontier's application is approved, do you intend to submit a new H2S Contingency Plan that includes the well?

A. Absolutely.

Q. Will Frontier agree to a condition that it have a new H2S Plan in place and approved before any injection occurs?

A. Yes. Yes.

Q. And is there any environmental benefits that will accrue if Frontier's application is approved?

A. Absolutely. The reduction in SO2 emissions, the CO2, you know, for the greenhouse gas emissions, and the fact it's going to allow us to increase the capacity of the facility is both benefit to us and producers and revenue for the state.

Q. Would it be fair to say this is part of the Southern Ute Tribe's overall environmental protection program?

A. Yes. Yes. They -- they have empowered us to look at all environmental projects. They don't bat an eye at doing environmental-conscious type projects. It seemed like it was a good idea and good thing to do even when economics are borderline.

MR. LARSON: That's all the questions I have of Mr. Prentiss. Mr. Examiner, I move the admission of Exhibits 1 through 3.

EXAMINER JONES: Did we talk about 3?

MR. LARSON: Yes. That's the H2S Plan and cover letter.

EXAMINER JONES: Exhibits 1 through 3 will be admitted?

(Exhibits 1 through 3 admitted.)

EXAMINER JONES: The director has said that any new AGI permits -- permitting will be done through the Commission, but this one was already on the docket, so -- but I am not saying that can't change, but that's what she said so far. So, just throwing that out. And as far as asking for CO2 sequestration, that's now Class 6, and that's still done through EPA out of Dallas, if you wanted to get it done that way.

THE WITNESS: Right.

EXAMINER JONES: I doubt that you would, but I'm not sure of the legality on whether you have to or whether you don't, that kind of a thing. That would be something for your attorney to look at. The Southern Ute Tribe owns it?

THE WITNESS: Yes.

EXAMINER JONES: Owns your company?

THE WITNESS: Yes.

EXAMINER JONES: Is that Bobs Radnick?

THE WITNESS: Yes, he is.

EXAMINER JONES: Is he still the head guy?

THE WITNESS: He is still the man.

EXAMINER JONES: I personally met him several times.

THE WITNESS: Yes.

EXAMINER JONES: What is your schedule that you need to get started on this?

THE WITNESS: You know, the plant expansion part of this, you know, if we were to push a button today because of availability of equipment, compression is the long lead item, and then the permit writing, we are looking at 18 months to two years, which we are behind the ball --

EXAMINER JONES: Oh.

THE WITNESS: -- with all the drilling activity that's going on. So we are going to do this up front separately just as soon as we get the permit approved, but it in itself has some long lead items that will take some time, the compression and then the choke -- not the choke, the Christmas tree.

EXAMINER JONES: So you need it as soon as possible --

THE WITNESS: Yes.

EXAMINER JONES: -- sounds to me like. Did Environmental Bureau give you an idea on the contingency plan, when it would be --

THE WITNESS: We have talked to them. We just need to start the process of getting with the permit writer, and that process takes -- it can take about six months for a Title V facility.

EXAMINER JONES: Do you want to talk to your lawyer about it?

MR. LARSON: I think he misunderstood your question. I think he is referring to the air permit and not the --

EXAMINER JONES: Oh.

THE WITNESS: I'm sorry. I apologize.

MR. LARSON: -- H2S Contingency Plan.

EXAMINER JONES: The H2S Contingency Plan that comes from OCD, did OCD give you an idea on when they could get it out to you?

THE WITNESS: They haven't.

EXAMINER JONES: They have not?

THE WITNESS: Not that I'm aware. The new contingency plan?

EXAMINER JONES: Yes.

MR. LARSON: The new plan hasn't been submitted.

EXAMINER JONES: It hasn't been submitted for their review yet. Okay. So can you think of any highlights of what that plan would entail?

THE WITNESS: It would include the acid gas injection well and compression, those facilities. It really wouldn't change anything else. It would just change how we would deal -- you know, it would add how we would deal with an H2S release that close to our facility of that concentration, and, of course, the training that goes along with the personnel and radius of exposure, it would change that a little bit.

EXAMINER JONES: What kind of population is around Maljamar?

THE WITNESS: The town of Maljamar is about two miles to the south. There is some -- Conoco Philips has a production office, but they don't have anybody out there. It's like a field warehouse, and that's pretty much it. There is nobody -- there is nothing.

EXAMINER JONES: The highway goes through there, doesn't it?

THE WITNESS: 529 is about three miles to the south, and 82 which goes through downtown Maljamar.

EXAMINER JONES: So you are basically north of the main population?

THE WITNESS: We are south of the town of Maljamar.

EXAMINER JONES: Oh, okay.

THE WITNESS: Yeah.

EXAMINER JONES: South of the town of Maljamar. Who would -- who would design the well that you are talking about, design the casing, the cement?

THE WITNESS: We are using Geolex as our consultant through the whole project.

EXAMINER JONES: They would actually sit in on the drilling of the well, also.

THE WITNESS: I would -- I would imagine. They are the consultant that we have hired.

EXAMINER JONES: They would be the engineer and company man on the well?

THE WITNESS: Yes. We haven't had a lot of discussions about that so that we could get through -- through the permitting process first. That is our intention.

EXAMINER JONES: This is all BLM land?

THE WITNESS: Right.

EXAMINER JONES: And the BLM didn't want to sell you that property?

THE WITNESS: They wanted to do a lease.

EXAMINER JONES: They wanted to do a lease. But I guess it's BLM minerals, too, so you would have to get the permit through BLM. Now who at the BLM do you work with, what office?

THE WITNESS: It's the Hobbs office because we are in Lea County.

EXAMINER JONES: Okay. Which operates south of Roswell and Carlsbad?

THE WITNESS: Carlsbad.

EXAMINER JONES: Carlsbad.

THE WITNESS: We are kind of straddling the county line. The plant is just over Lea County. Our gathering system is over in Eddy County.

THE WITNESS: So we are dealing with both of them, depending on what we are dealing with.

EXAMINER JONES: How close are you to the Chaves County line?

THE WITNESS: We have a compressor site in Chaves County. We are probably, as the crow flies, about 30 miles.

EXAMINER JONES: I think that some of that horizontal drilling in the Bone Spring -- I think it's the Yeso -- is on the -- real close to the Chaves County line.

THE WITNESS: Chaves County.

EXAMINER JONES: So you are right in the middle of all that activity then?

THE WITNESS: Yes.

EXAMINER JONES: And the -- you are gathering the -- the casing head gas. Is that --

THE WITNESS: Correct, yes.

EXAMINER JONES: It's mostly casing head gas coming out. So is it pretty rich?

THE WITNESS: It is. It's about 6, 7 GPM, what we gallons per thousand cubic feet of gas. Years ago they drilled a lot of the Morrow wells, and we had a lot of Morrow gas which allowed us to blend, and we were able to get to the 60 million, but nobody is drilling any Morrow and that Morrow gas depletes pretty quick.

EXAMINER JONES: So it's a pretty nice deal for the owners?

THE WITNESS: Yes. And the producers. We have to do something to try to help them, you know, have somewhere to go with the gas.

EXAMINER JONES: Oh, yeah. So the actual operator name would be Frontier Field Services LLC?

THE WITNESS: Correct.

EXAMINER JONES: And it's got -- I didn't see a bond yet.

THE WITNESS: We haven't applied for it yet.

Alberto told us that would be one of the first steps we do once we secure the permit.

EXAMINER JONES: Okay, yeah. Yeah. We can't release this permit until you have the bond in place, but the drilling permit, maybe, you know, it's -- maybe we can do that. It's kind of optional on that one. David, correct me if I'm wrong with that. You said you have a separate -- you are going to put a dehydrator right before the wellhead. Is that right?

THE WITNESS: Yes.

EXAMINER JONES: Is that before the compression end?

THE WITNESS: It's actually after the compression.

EXAMINER JONES: So you compress, dehydrate?

THE WITNESS: Yeah. The compressor is going to be a multistage compressor through one of the interstages we are going to have to dehy.

EXAMINER JONES: And you are expecting some waters to come?

THE WITNESS: Correct.

EXAMINER JONES: Get knocked out of that?

THE WITNESS: Yes.

EXAMINER JONES: What do you do with your plant wastewater now?

THE WITNESS: The produced water now goes to -- we do two things with it. Conoco takes to their waterflood, and then if they can't take it, we truck it out and go to the disposals, one of the several disposals we have in the area.

EXAMINER JONES: So they --

THE WITNESS: Conoco primarily takes it, you know.

EXAMINER JONES: In the MCA, you mean?

THE WITNESS: Yes.

EXAMINER JONES: And that's where you used to work, right?

THE WITNESS: No. I worked at the Maljamar Plant when it was owned by Conoco prior to the merger.

EXAMINER JONES: You have been one of those guys commuting from Hobbs all these years.

THE WITNESS: I commute from Carlsbad, 50 miles. Hobbs is 45.

EXAMINER JONES: Were you guys -- who supplied the information on the notice? Did you guys take care of that with Geolex or did --

THE WITNESS: They did it for us.

EXAMINER JONES: They did it?

THE WITNESS: Yes.

EXAMINER JONES: And the blended Bone Spring, Yeso Paddock is 2 percent CO_2, pretty close?

THE WITNESS: It varies, but that's a good number.

EXAMINER JONES: Which one is higher?

THE WITNESS: The Yeso Paddock is higher. Some of the Bone Spring, the horizontal, is coming in sweet, some of it to the south of us.

EXAMINER JONES: You got 750 miles of gathering lines?

THE WITNESS: We do. It's kind of a massive spider web. It's an old facility. We replaced a lot of the steel with poly, and we also have a high pressure system where we bring in -- we compress it in the field, and over the years since Frontier's owned this, they put money back into the gathering system, changing out a lot of old spiral round steel to poly.

EXAMINER JONES: You said you compress and then it leaves the plant and goes not too far to the well. Is that correct?

THE WITNESS: Correct. That's -- it's probably a football field.

EXAMINER JONES: Okay.

THE WITNESS: Yeah. It's not very far.

EXAMINER JONES: So do you guys design that pipeline or that -- that line.

THE WITNESS: Correct. Our engineering department would -- would design it based on the composition and the pressure.

EXAMINER JONES: And how deep would it be buried and what would it be made of?

THE WITNESS: To be honest with you, we haven't gotten that far. If I have my choice, I'm not in favor of burying it. I would like to put it on a rack and leave it above ground.

EXAMINER JONES: Yeah. So this lease would last a long time with the BLM?

THE WITNESS: Yeah. We would be looking at a 99-year lease, I believe. No further than it is, I think we can do that, leave it above ground, that way we can do all the corrosion monitoring and not worry about it being buried, another sour line being buried.

EXAMINER JONES: And I don't know what the NSR and Title V permits are, but I don't think I need to know that.

THE WITNESS: Yeah, they are.

EXAMINER JONES: NMED, is that correct?

THE WITNESS: Yes.

EXAMINER JONES: That's the only other entity you deal with?

THE WITNESS: Yes.

EXAMINER JONES: David, do you have any questions?

EXAMINER BROOKS: Well, you asked me a question, asked if you were correct on something, and I wasn't paying close enough attention, and I wasn't sure what you were asking me. Do I need to --

EXAMINER JONES: The bonding required to permit drilling of the well.

EXAMINER BROOKS: Oh, yeah. This is a Class 2 Well, I believe.

EXAMINER JONES: Right, it's Class 2, but, I mean, just the APD to get -- APDS are optional on Rule 5.9. Is that correct?

EXAMINER BROOKS: Regarding that 5.9, that's another issue. I thought you were thinking that this was an environmental well and bonding would be a discretionary amount. But it's a Class 2 Well, and the bonding is a set amount per -- for the well, but if -- if the operator has a blanket bond, then they wouldn't even need a bond.

EXAMINER JONES: They will get either a blanket bond --

EXAMINER BROOKS: A $50,000 blanket bond, or a $1 per foot plus 5,000 --

EXAMINER JONES: Single well.

EXAMINER BROOKS: -- single well bond. Whereas, if they were doing an environmental well, they would have to have Environmental Bureau. No, I have no questions. I -- Mr. Jones threw me when he was talking, and I had to stop and figure out what it was because when he said AGI, to me that means adjusted gross income, so --

EXAMINER JONES: Thank you very much.

REDIRECT EXAMINATION

BY MR. LARSON:

Q. I have one follow-up question. Could Frontier have a bond in place in say 10 business days?

A. Yes, if they needed to.

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

ALBERTO GUTIERREZ

(Having been sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. LARSON:

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

A. Yes, my name is Alberto A. Gutierrez.

Q. Where do you reside?

A. In Albuquerque.

Q. And what is the name of your company?

A. Geolex Inc.

Q. And what capacity do you serve at Geolex?

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

Q. And could you briefly summarize your educational and professional background?

A. Sure. I have a bachelor's degree in geomorphology from the University of Maryland in 1977, and subsequent to that, I have a master's degree in geology from UNM in 1980, and subsequent to that I have taken many short courses and other continuing education relevant to maintaining my professional certification as a professional geologist.

Q. And did Geolex prepare Frontier's application in this case?

A. We did.

Q. And you were personally involved in that preparation?

A. Yes, sir.

Q. Have you previously prepared other applications for approval of acid gas injection?

A. Yes, I have.

Q. And did you testify at hearings on those applications?

A. I have.

Q. And were you qualified as an expert in petroleum geology and hydrogeology during each of those hearings?

A. Yes, sir.

MR. LARSON: Mr. Examiner, I move for the qualifications of Mr. Gutierrez as expert in petroleum geology and hydrogeology for purposes of this hearing.

EXAMINER JONES: He is so qualified.

Q. Before we get into your testimony, Mr. Gutierrez, I would like to address two questions the Examiner asked of

Mr. Prentiss.

A. Yes.

Q. In relations to a modified H2S Plan, have you had discussions with the Environmental Bureau on behalf of Frontier?

A. Yes, I have.

Q. And who did you communicate with at the Environmental Bureau?

A. When we submitted this Rule 11 Plan on behalf of Frontier, we met with Glen and Leonard and Richard to kind of go over the plan. And what we -- what we decided to do jointly was that there were basically two things that needed to be done. One was that Frontier had, in response to Mr. Sanchez's letter requesting a H2S Contingency Plan, brought to the attention of the Division that there had been a plan in place, and it did exist pursuant to Rule 118, and so we submitted that plan because it appeared that, you know, during the -- the transfer of records to electronic records that the Division didn't have a copy of that plan, so we did submit that plan, but it had been in place for quite a few years, as Mr. Prentiss mentioned earlier.

But then what we did was meet with Glen and with Leonard from the Environmental Bureau and go over what modifications needed to be done to that plan to make it consistent with Rule 11. And Mr. Sanchez's letter had requested that those modifications be supplied to the Division prior to August of this year, 2011, and we submitted those modifications pursuant to the discussions that we had had with Glen and Leonard on May 10, and that's the plan that you have in front of you.

The reason why we did not include the AGI in that plan was because since Frontier is still in the design process of the compression facilities and the exact layout of the equipment, basically the only modification that's going to take place for the Rule 11 Plan would be to make a change showing where the H2S detectors are going to be and the procedures associated with the added facilities that haven't yet been fully designed.

And then, also, because, as Mr. Prentiss pointed out, when they crank up this well, if it is approved when they crank up this well initially, it will only be receiving about just under a million cubic feet a day of acid gas to be injected, but then we are requesting approval to inject up to 2 million cubic feet a day because that will take care of the added acid gas volume that would be associated with the plant expansion.

So what we envision is that, when we do the revised Rule 11 Plan, which would be, I would imagine, relatively soon after this application would be considered and approved, then we would do the radius of exposure for the full 2 million cubic feet a day so that we wouldn't have to come back and then revise the plan again once the plant expansion is done, because essentially the plant expansion itself isn't really going to affect the configuration of the detectors and that kind of thing because that's already existing on the plant property itself.

So that's basically where we are with that, and the Environmental Division was fine with that approach.

Q. The Examiner also raised a question about whether the sequestration of CO2 might kick us into a Class 6 designation for the well, which may involve the Region 6 in Dallas.

A. Yes.

Q. Have you had any communications with Region 6?

A. Yes. Not just on this topic, but it might be of interest to the Hearing Examiner that I did speak with Region 6 because one of the concerns that we had wasn't directly related to the C-108 process, but under the new mandatory greenhouse gas reporting rules, under subpart RR and UU, those rules have some very specific requirements for wells that inject CO2, and we were concerned, and a number of our clients have been concerned about whether Class 2 wells, which, as Mr. Brooks pointed out, this is a Class 2 Well, whether those wells would fall under the new requirements of Subpart RR of that mandatory greenhouse gas reporting rule because those requirements, in effect, include some of the requirements that are associated with Class 6 wells.

And it was interesting because Region 6 hadn't really thought about this issue, and they had to end up going to headquarters to get guidance. And, as it turns out, we did get back a response in writing from Region 6 via their discussion with headquarters saying that Class 2 wells, specifically, will not be subject to Subpart RR of those regulations, which are the ones that essentially consist of the Class 6 wells, but that Class 2 wells would be only under the UU designation which would just require essentially a reporting of the amount of CO2 that is injected on a quarterly basis beginning in for the year of 2011 and March of 2012. So there was a definitive determination that Class 2 wells will not fall under that RR designation.

But interestingly enough, the wells that -- not only this acid gas injection well, but other wells that we have designed and that the Division has approved previously are really meet or exceed the Class 6 well specifications in terms of the designs of the wells themselves. As a matter of fact, for the Class 6 wells, when they finalized the rules, one of the things they did was remove a requirement for having a subsurface safety value, for example, in the well. If it's a Class 6 well, it is not required to have a subsurface safety valve, yet, for all these Class 2 AGIs we spec out and include a subsurface safety valve as part of the well design.

Q. At this point I would ask you to identify Exhibit Number 4.

A. I don't think I have a copy of Exhibit Number 4 here. I see 5.

MR. PRENTISS: It's under your -- right here.

A. Okay, sorry. Yes, Exhibit Number 4, is a hard copy of the power point presentation which is up on the screen here.

Q. And are these true and correct copies of the power point slides that appear on the screen?

A. Yes, they are.

Q. In addition to preparing the application for Frontier, were you also tasked with providing personal notice to the individuals and entities entitled to receive written notice of the filing of the application in today's hearing?

A. Yes.

Q. And how did you identify the names and addresses of those individuals and entities?

A. As the Hearing Examiner is well aware, the Division's practice has been to require that notice be provided to all surface owners, all operators, all lessees. And in the event that there is unleased mineral interests within the area of review which has been defined as one mile from the radius from the well, that the notice be provided to, in the event that there is unleased, to all the mineral owners. That didn't apply in this case because there were no unleased interests. And also to any residents or businesses that fall within that area of review.

And Geolex retained MBH Land Services out of Roswell, which is a land company, to obtain the names, addresses, contact information and to identify all of the surface owners, lessees, operators, residents within that one mile area, and we provided written notice to all of those parties.

Q. Okay. And are lists of the names and addresses of the operators, surface owners, lessees, and business owners within that one-mile radius attached to the application?

A. They are, they are included in -- those tables of those owners and operators and other parties are all included as Appendix D, as in David, to the application.

Q. And could you next identify Exhibit Number 5?

A. Exhibit 5 is a copy of each of the letters which were sent to the parties that required individual notice via return receipt requested via certified mail, and a copy of the certified mail receipts, and then also -- and that's -- that's what is in Exhibit 5.

Q. Okay. And are the documents that comprise Exhibit Number 5 true and correct copies of the letters that you

signed and sent by certified mail and return receipts?
A. Yes.
Q. And were any of the notice letters that you sent returned as undeliverable or sent to an incorrect address?
A. There was one that was returned. It wasn't that it was undeliverable, it's just no one ever signed for it, so, you know, they keep the certified mail for X amount of time and then they return it to us. And that was one that was sent to Endurance Resources LLC in Addison, Texas.
Q. And your -- did your contracted landman follow up to ensure that you had sent to a good address?
A. When we received that application back, we did -- I instructed MBH to go back and look and make sure that the address that we had for Endurance Resources was the correct address and the correct contact information. And then I, I personally, looked at their website on the -- and identified that indeed the address that we had sent it to was the correct address of record, and so we had sent it to the correct address.
Q. And in addition to the personal notice letters that comprise Exhibit 5, did you also publish notice of the filing of the application of today's hearings?
A. Yes. I submitted this -- a draft notice to the Division, to Mr. Ezeanyim, and also to Florene to make sure that the wording was adequate. And then we filed a legal

notice in the Hobbs News Sun which was published on May 31, 2011, that was a notice of this application and this hearing.

Q. Okay. Could you identify Exhibit Number 6?

A. Exhibit 6 is an affidavit of publication of same notice and with a copy of the legal notice.

Q. And is Exhibit 6 a true and accurate copy of the advertisement and affidavit of the advertisement in the Hobbs News Sun?

A. Yes, it is.

Q. And are you aware of any opposition to Frontier's application in this case?

A. No. To the contrary, I have discussed the application both with the BLM and also with a number of the producers in the area, and I think actually there is support on both counts.

Q. Would you move to Slide 9, please. Generally speaking, what criteria do you use for evaluating potential reservoir for injecting H2S and CO2?

A. Well, the first thing we look for is a reservoir that is laterally extensive and sufficient porosity and permeability to be able to contain and to accept within the -- within a safe injection pressure the amount of gas that we intend to inject, and then we look for, again, this reservoir to be sealed so that both above and below it is able to permanently contain and keep that gas sequestered in place.

We also look for a reservoir that is going to not negatively affect in any way either existing or potential production as a result of the injection, and that one is that is isolated from fresh water resources, groundwater resources, or surface water resources, and that there are no structures that would allow that gas to escape that reservoir.

And then the last two items basically is we typically look for a reservoir that has excess capacity so that we -- we can make sure that we can get all of the gas put away for the lifetime of the project, and one that has a compatible fluid chemistry with the injected stream. And we looked at those criteria, which are the normal criteria that we look at when we look for AGI reservoirs, and this reservoir that we have identified meets all of those criteria.

Q. Could you identify for the Examiner what's been called the primary injection zone in the application?

A. Yes. The primary injection zone is in the Lower Wolfcamp in the -- in the area of the plant that exists at about -- from about 9700, 9800 feet to about 10,000 feet.

Q. And there are also two identified secondary injection zones in the application?

A. Yes. As you will see a little bit later on in my presentation, we have also identified two zones in the Lower Leonard that are immediately above the Wolfcamp which have potential -- they don't have the same capacity that we had in the primary injection zone, but they do have some potential capacity, although, given where we are putting the well, we just don't really know whether we will be able to utilize or want to utilize those zones, but we would like to have approval to use them in the -- to have them behind pipe in case they want to be used in the future.

Q. Could you move to the next slide, please. And in performing your geologic evaluation of these three zones, did you identify and evaluate all oil and gas producing injection wells within the one mile radius of the proposed AGI well?

A. Yes, we did.

Q. And how many wells are located in that one mile area of review?

A. I don't recall the exact total number of wells. They're included, the list, complete list of those wells is included in the application in Appendix C, and I believe the actual number is included in the application. But the bottom line is that the great majority of all of the wells within the one mile area of review are much shallower than this injection zone. They are primarily Delaware Sand Wells, and they are well above this zone. In terms of wells within the one mile area of review that penetrated the proposed injection zone, there were only 12 wells, six that are plugged and six that are active that have either penetrated or are completed below the proposed injection zone.

Q. And did you review the well records for each of those 12 wells?

A. Yes, we did.

Q. And what was the result of your evaluation of those wells?

A. Well, we not only reviewed the logs and plugging information for each of those wells and we provided in Appendix C a detailed diagram of each of those 12 wells and a CD that has all of the information, all of the well records for each of those wells. But in addition to that, we used 3-D which is something that we haven't really done before, but one of the things that we were concerned about is that outside of the area of review, there are a few saltwater disposal wells into the Wolfcamp, and we wanted to see what the relationship of the reservoir that we were looking at was to those wells, and so we used 3-D seismic. We obtained 3-D seismic for the whole study area and mapped out the reservoirs so that we understood exactly the lateral and vertical extent because these Wolfcamp reservoirs are really isolated reservoirs within relatively fine-grained material and they're not necessarily connected, even though they are at the same stratigraphic interval.

So using the information available for the wells that were plugged that are active in the area and the 3-D seismic, we were able to clearly understand what the relationship of those wells was to our proposed injection zone. And what we have found is that there -- those wells are all well cemented through the injection zone, and we don't anticipate for, as you will see later on in the presentation, that there will be any interaction with those at all.

Q. Could you move to the next slide. Could you generally describe the geological features of the area surrounding the proposed AGI well?

A. Yes, just before we go on to that, I wanted to point out that this next slide, Number 11, does show all of the 12 wells that penetrate the injection zone and where they are located relative to the proposed well. And those 12 wells, again, all of the details associated with those wells are included in the Appendix C.

Okay. So, in general, in terms of our geologic evaluation, the first thing we did was identify the background regional geologic data so we could understand the general geology of the area. We then identified and evaluated all of the wells in the local area, and we used that data to do our initial feasibility analysis of the --

the the potential for acid gas injection. And then we evaluated that stratigraphic information in conjunction with 3-D seismic data to confirm that the reservoir met those criteria. And then we constructed cross sections with all of the available logs, as well as with the seismic data itself, and we then assembled all of that information in the C-108 and submitted it to the Division for review.

Q. Could you move to the next slide? And this depicts structural features of the Permian Basin in the area of the proposed well?

A. Yes. In general, this depicts the main structural features and kind of depositional environments of the Permian Basin. The plant is really located on the very edge of the Northwestern Shelf where that Shelf begins to drop off into the Delaware Basin. And, as you can see, that -- that Shelf was located to the north and west, and then the deep water of the Delaware Basin is located to the south, and then there is this channel that connected the Midland and Delaware Basins, and this plant is located just to the north and west of the Hobbs Channel there.

Q. And does the next slide also depict the regional depositional environment --

A. Right.

Q. -- relative to the Maljamar Gas Plant?

A. Yes. This is a cartoon, if you will, block diagram of the regional depositional environments in the area where the Maljamar Plant is located. Essentially, like I mentioned, as you can see to the north here, what would be to the north and west, you have from continental environments to a backwater lagoon, and then a barrier reef or an oolite bank that then was -- had a number of turbidites and other breaches in there that went into the Shelf deposits and then into the deeper water of the Delaware Basin. And like I mentioned, the Maljamar Plant is really located along this kind of barrier reef area, edge of the Shelf.

Q. And have you prepared any other slides relative to your structural analysis?

A. Yes. In general, we -- I have looked at both stratigraphy and structure here, and the next series of slides displays the results of that analysis. Would you like me to go through those?

Q. Sure.

A. This slide is a structured contour map. It's interesting to note this, when we then look at the seismic data, because it gave us a much better definition of the structure. But, as I mentioned, what we have is essentially a gently dipping structure from the -- the area of the northwest Shelf here down towards the Basin, and then this zigzag line is a line of structure from essentially northeast to southwest that we constructed to get a just general idea of the stratigraphy in the area, and that is shown on the next slide here, this cross section -- and I apologize for the -- it's hard to get all of these things on, but the details we'll see in some subsequent slides.

This is just to give a general picture, as you go from the northwest Shelf, this is the top of the Wolfcamp here, and the injection zones that we are looking at in the Wolfcamp as a primary zone are essentially these zones here that have the -- the star marked on them in two wells that are relatively close to the plant.

And I mentioned some saltwater disposal wells that are located farther to the south in the Wolfcamp, and these wells here we use to give us a little better idea of the injectability of that zone, but they really are in a separate zone in the Wolfcamp, and you will see how we were able to determine that based on the seismic analysis as we go on.

But there were two production tests done in the Wolfcamp in the immediate vicinity of the plant, and both of them were wet, so the zone, really, we are very confident it doesn't have any recoverable hydrocarbons in it.

As I mentioned, we purchased, on behalf of Frontier, a big block of 3-D seismic data which was available for an area. You can see in this diagram in the red square is the area of the plant, and we purchased 3-D seismic all the way around for a two square mile area around the plant. We then had synthetic seismic profiles done from the sonic logs of this well here, this well here, and this well here, and then subsequently, actually, another well that is located in this area that is plugged, the Baish well. So we -- we were able to get very good depth control using this synthetic seismic profiles that we constructed with those wells.

This next diagram shows the -- that same area, and it shows this Baish Well, which is relatively close by that we also did a seismic -- synthetic seismic on. And then these two wells that are here outside of the area are the two saltwater disposal wells in the Wolfcamp that we were talking about. So one of the things we wanted to see is, what did our Wolfcamp Reservoir in the area of the plant look like compared to these wells because we have some very good injection data on these wells that was very encouraging to us, but we wanted to understand how that related to the potential for injection in our area.

So if you will notice on here, on this, there is a black line that goes like this through this Baish Well, and that is a -- the next slide is a seismic section along that line, and there is a couple of interesting features I would like to point out on here. You can see that down deep below the Cisco and into the Strawn, there is a little bit of a structural discontinuity here, probably a fault, but that fault peters out quite a ways below our zone, the Wolfcamp here.

This area here that you see in the Wolfcamp -- the plant, by the way, in this cross section, the area of the plan would be approximately in this area just north of where this Baish well is. This kind of appearance is, typically, it shows some degree of porosity development and secondary porosity associated with maybe some fracturing in the Wolfcamp, probably depositional kinds of features. But as you can see further to the north, we don't really have that kind of an effect.

But one of the things that we do have is -- and that we look for -- is a significant contrast between in the amplitude of the response, seismic response, which indicates porosity development, and we saw that here within the Lower Wolfcamp and then in a couple of zones here in the Lower Leonard.

So the next thing we did was take this, and I can't say that I did this with colored pencils, although it seems like I might have, but what we did was do an enhancement of this vertical section which just takes the different amplitudes and shows them in different colors. Essentially the warmer colors, like the reds, and then where there is significant contrast between those and the up -- overlying or underlying zones, those typically indicate porosity development unlike if you see, for example, here, a very continuous long one, that typically is more indicative of a shale, but where you have these kinds of isolated features, they are more indicative of a better porosity, and that agreed quite well with the data that we saw in the well logs for the site.

So one of the next things we did, which was a really -- was a very interesting exercise was we took what is called a time slice map of the 3-D seismic. One of the great advantages of this 3-D seismic is that you are not restricted to just a cross sectional view; you can really take a look and slice it any way you want.

And so one of the things that we did was take our zone in the Lower Wolfcamp, our primary target for injection, and took a time slice of the porosity development in that zone, and what we basically saw is that this is, again, this little white square is where the plant is, and this is -- the warmer, the red tones going into yellow basically are the porosity development in that zone, so you can see that what we are looking at is really a fairly confined reservoir that is -- the geometry of that indicates that it's probably a debris apron of kind of carbonaceous and sandy material that was built on the -- on the boundary of that Shelf margin. But what it allowed us to do was to identify essentially what the lateral extent of that reservoir is, and that allowed us then to calculate what the capacity, based on the porosity that we developed from the logs and wells that penetrated that area, it allowed us to develop a good idea of what the porosity and permeability are.

And the interesting thing is that -- and I have highlighted it in the box -- that while this zone isn't laterally connected to the wells that are outside that one mile area of review that either produced -- there is some wells that produced from the Wolfcamp outside of this area miles away, they really don't anymore, but there still are some down here at the -- off of the section down here, there is a couple of wells that are saltwater injection wells into the Wolfcamp, and we can see this reservoir is not connected to those wells, but it's probably in a very similar kind of geologic feature.

Q. Mr. Gutierrez, did you also evaluate seismic data for the two secondary injection zones that are identified in the application?

A. I did, but one last slide, this one shows another cross section that I would like to just show you where that is, because what we did is then after we did this time slice, we took a cross section this way across the entire width of the reservoir to look at what it looks like in a cross section, and you can see the plant is located here, and you can see that porosity development here. Here is a very good porosity development in the area of the plant. It peters out to the west, and then again peters out here to the east.

And then, as you mentioned, we -- we then, after doing that for this zone, this is a structure map which overlays that area, and you can see, again, that we have just a gently dipping zone to the south and east here. And here is our -- the outline of our reservoir.

We also identified, as you mentioned, a couple of what we call secondary targets above the Wolfcamp. At the time when we did this analysis, there -- we had not, Frontier -- we had not yet developed a recommendation. Frontier had not yet decided whether we would complete the well on the plant site, and we also had evaluated the possibility of using the existing Baish wellbore, which was located to the south and west of the plant site as a potential well to use for AGI. We decided that that was not a good idea because it just was not in the most favorable location in terms of reservoir development.

As you can see, these Lower Leonard zones, there is one piece of one right here in the area where the well is slated, but most of the porosity development is to the west of the plant in this zone, and similarly in this other zone in the Lower Leonard. So we don't really know whether those -- those zones are both smaller reservoirs, we don't really know how good they are going to be, but we are going to test them when we drill the well.

We did the same kind of analysis for each of those zones. You can see them here in the Lower Leonard, the development, and you can see it's generally to the west of the plant site, although there may be a little bit here. And then similarly here in the lower portion of the Lower Leonard, you see a little development under the plant site and a little bit to the west.

So we did the same kind of analysis for those zones and wound up with having this kind of an outline for the primary reservoir in the first one in the Lower Leonard and then the second one in the Lower Leonard. And generally they were west of the plant, but we would still like to test those zones when we drill the well.

So when you overlay all of those zones, what you see shown in green here is the outline of the primary injection target which is where our well would be located in this approximate location, and then the secondary targets, which we may or may not encounter when we drill that well. We then calculated what was the total porosity for each of those zones in terms of capacity for injection of acid gas. And what we started to do in response to the Division's request -- and, in fact, in a hearing sometime earlier, Hearing Examiner Mr. Jones was wanting to look at reservoirs in a little more sophisticated manner than just a kind of plug flow model, and so one of the things that we have done to address that is to look at the irreducible water saturation within the reservoir and reduce the available porosity by taking that irreducible water saturation into account, and that's what we have done here.

The irreducible water in this zone is about point 45 or 45 percent, so we really only have about 55 percent of the available porosity to us for injection, and we took that into account. And so what we see is that we've got a capacity of injection in this reservoir of about 24 million barrels for the primary zone and then 9 and 3.8 million in the secondary zones, which we may or may not encounter when we drill the well.

Q. Over what time frame will or -- sorry -- has Frontier proposed to inject the AGI well?

A. Well, we have conservatively estimated that Frontier would be injecting over 30 years into this reservoir, and to be conservative, again, we calculated the injection based on the maximum of 2 million cubic feet of TAG a day for 30 years in anticipation that, at some point, probably several years after the initial injection happens, they will -- which would be at about a million cubic feet a day, they will go up to 2 million cubic feet a day.

So what we did was estimated as if it was injecting 2 million cubic feet a day from day one. And we took into account -- we have some software now that allows us to look at the reservoir pressure and temperature conditions and what volume of -- of the reservoir that TAG under those pressures, specific pressure and temperature conditions and under the specific make up of that TAG, in other words, 88 percent CO2 and 12 percent H2S, how much space that is going to occupy in the reservoir over a 30-year time period.

And what we found is that for the -- for this particular case, over 30 years we will have about 9.3 million barrels of TAG introduced into the reservoir, and the calculated reservoir volume, and that is taking into account the irreducible water, was 24 million, so we would be using just under 39 percent of the available capacity of that reservoir for this injection project.

If you do that calculation in terms of just a radial area, it would be about 73 acres and a little less than two-tenths of a mile of -- of area that that plume would encompass.

Q. And does the next slide graphically show the area that --

A. Yes. The next slide shows several things. One is the purple circle that you see out here, that is the one mile area of review, and it shows all the wells that lie within that or adjacent to that one mile area of review. Then we have outlined on the map kind of the outline of the primary injection reservoir in the Wolfcamp, and this is essentially what that outline is. And then within that, what we have done is take the 79 acres and not really have a plug model that would show two-tenths of a mile radius all the way around the well, it would be little smaller than what you see, but, instead, this blue line takes that radius and accommodates it to what we know the limits of the reservoir are. So this is about what we anticipate the plume to look like after 30 years within that Lower Wolfcamp if we are injecting solely into that zone.

Q. Excuse me. And what is the maximum injection pressure that Frontier is requesting approval for?

A. Based on the -- the calculations using the specific gravity of this TAG and the formula that is provided in OCD guidance, we have calculated a maximum allowable injection pressure of about 29 hundred and 73 PSI.

Q. And how does that compare to the fracking pressure?

A. It -- that formula is specifically designed to provide a significant safety margin below the fracking pressure of that formation.

Also, I just want to mention that the saltwater disposal wells that are located down here, this is one of them, and another is actually off the map, that are in the Wolfcamp, they are not within this same unit, but they are in probably a similar -- these same kind of little reservoirs exist all along that trend of the Shelf margin in the

Wolfcamp.

And the good thing is that this well, for example, down here is taking in excess of 5,000 barrels a day of saltwater at a pressure of approximately 12 hundred pounds, so it's a pretty low injection pressure which gives us some good confidence about what we will be able to -- that we will be able to stay well beneath the allowable injection pressure for our zone.

Q. And what design elements will be incorporated into the proposed injection well?

A. I know that the Hearing Examiner asked earlier about the design of the well, and, in fact, Geolex has already designed the well. We haven't done the extremely detailed design, but we have done sufficient number of these that we've got a pretty good design, and basically these are the primary elements.

The well is going to be comprised of three strings of casings, surface casing down to about 550 feet, which is about 390 feet below the lowest fresh water zone that is in that area, and then an intermediate string down to about 4200 feet which is a requirement by the Division, locally they want to go all the way through the salt in that intermediate string, so that would take us well through that zone, and then the production casing down to the total depth of 10,000 feet.

Within the well itself we would have a packer that is set -- it's an inkaloid packer. It's set, and it will be set in a corrosion resistant joint, two joints, typically corrosion-resistant joints that we set the packer in. The production casing would be perforated below those two joints.

And then stabbed into that packer would be corrosion resistant L-80 flush joint special threaded tubing. It would not be lined because this is a dry injection well, so it would just be corrosion resistant L-80 tubing with an automated subsurface safety valve set at approximately 250 feet below the surface of the well, and then having again a corrosion resistant Christmas tree on the well.

And we are, in this well, we're likely to include a choke in the packer because we, if we find that the reservoir pressures are relatively, you know, low in terms of for the rate that we intend to inject, we want to make sure that that gas stays in super critical all the way down, so we want to maintain the injection pressure at least 14 hundred pounds in that tubing all the way down. And we may not have to use one, but we have a provision for that in the design.

And then we also will have a -- a pressure regulation system at the top of the well that will allow us to make sure that the MAOP is not exceeded. And, of course, there will be meters that will continuously record the pressures and volumes of injected gas.

And then one thing I failed to mention is that the annulus between the casing and the tubing will be loaded with an inert fluid. We typically have used diesel, and we like that because it prevents corrosion, but we've run into a bit of a problem over the last few months in terms of trying to find people that can pump diesel.

Now there is a lot of people that are concerned about pumping diesel because of -- of the low flash point, and they just, from a safety perspective, they are concerned about the actual pumping of the diesel, not having it in the well. So we may look at another kind of inert fluid just depending on whether we have problems with that, but we think we still will be able to use it and find someone that can do it.

But, in either case, there will be an inert fluid that would be between the tubing and the casing, and that will be -- the pressure -- that will be a sealed system, and the pressure is monitored in that annulus continuously and recorded and sent back to the PLC of the plant so that if that pressure rises, we know, we have a potential tubing leak. If that pressure drops, we know we have a potential casing leak. So that's another safety system that's incorporated into the well.

Q. And have you prepared a schematic of the proposed well for Frontier?

A. Yes, I prepared two, a general schematic of the AGI system, this is shown on this slide. You can see essentially that they will come off, as John mentioned in his testimony, they will be coming off of the line, the already existing pipeline that goes to the flare and teeing off that line and going just immediately south of where the flare is, southwest of it to the compression facility, and that's where the acid gas will be compressed, and then approximately 120 to 150 feet away there will be the -- the actual well itself from the compressor.

So we have the compression, and then an automatic safety valve, and then the high pressure line that goes to the well, and then that connects to the Christmas tree and then down hole through the automatic safety valve into a retrievable production packer that would be set at about 9750 for the primary zone in the Wolfcamp of 98 to 10,000.

You know, if in the future we decided to use the these upper zones, then that packer could be moved up and -- and what we might do in the event that those zones look promising is we probably would set a couple of corrosion resistant joints further up the casing in the area where we would move the packer up to, if we were going to use those zones later. But this is, more likely than not, this is the way the well would be completed with probably a provision for that future use of those above zones.

This is a more detailed diagram of the well itself. As I mentioned, we've got this first set of casing 13 and 3/8 to about 550 feet. We then have an 8 and 5/8 set down to 4200 feet, and we then have 7 inch casing all the way down to the proposed injection zone primary target from 9800 to 10,000 feet with the packer set at 9750. We also would then have the -- the tubing, as I described here, stabbed into that packer. Down here would be the choke and one-way valve in the packer, and then up here is the subsurface safety valve.

Obviously we would be conducting an MIT upon completion of the casing of the well, and then as routine practice, we would be conducting MITs every two years thereafter.

Q. And will all of the final design elements be included in the modified H2S Plan that will be submitted to the Environmental Bureau?

A. Yes. As I mentioned, in effect -- and this is what I have discussed with Glen and Leonard -- that the addition to the plan basically will be to deal with the sensors associated with the compression facility because they already have H2S sensors in the vicinity of the flare, but there will be some added due to the compression facility and then around the well itself. And once we have those design elements incorporated, it will be very easy to incorporate those into the -- the existing Rule 11 Plan.

And, I think, just to save time and effort, I think the Division was comfortable enough with the Rule 11 Plan that has been submitted for the facility already that they are going -- that my understanding is that they intend to delay their basically detailed review of that plan until we submit the modified plan that incorporates the AGI, and then we would sit down with them and make sure that it meets all of the requirements.

Q. Are there any water wells within the one-mile area of review that you analyzed?

A. Yes, there is one water well. It's located within the one-mile area. It is this well that's called Reliant Processing, and it is a well -- I'm not sure, based on the State Engineer Records, whether the well is still being used or not, however, it doesn't appear to be plugged. Anyway, the total depth is 158 feet, and that's pretty much the base of what is really fresh water in that area. There is some very low quality, probably 10- to 11,000 TDS water in the Rustler in this area, but in terms of actual water wells, this is the only one.

Q. In your opinion, will the proposed well as designed adequately protect ground water?

A. Yes. The conductor casing is set over 390 feet below the deepest fresh water in the area, and it will be obviously cemented to the surface, and then within that we will have an intermediate string set to about 4200 feet. It's below all of the potential fresh water in the -- in the Rustler, even though most of the water in this area in the Rustler is -- I think it's a stretch to call it fresh water, but that will also case off all of those shallow productive units in the Delaware Sands and in those units.

And then below that we'll have the full production string. And then the tubing design and all of the components that we discussed earlier, all of those act to protect both the fresh water resources in the area, as well as other production.

Q. Could you briefly summarize the well design factors that you believe will assure the safety and integrity of the injection well?

A. Yeah. Basically I think I've gone through those just now. I will mention, however, like I said, the tubing design and subsurface safety valve and the monitoring of that annular space is crucial, and then also the fact that we have an experience with now eight similar installations in New Mexico and Texas that have this design and are working well.

Q. Could you also briefly summarize the geologic features that you believe will assure the safety and integrity of the well?

A. Yes, combined with the -- with the well design itself, we've got a very favorable geologic environment that will assure that, one, we don't have any -- and we have a high degree of confidence in this. With traditional geologic tools you can have a pretty good degree of confidence, but when you have that 3-D seismic, it helps nail it down that we don't have any faults or structural pathways in the area of review that affect the injection zone.

The Caprock is a low porosity and permeable rock which is an effective barrier both above and below the injection zone. The injection zone is deeper than most of the adjacent production. All of the freshwater zones are going to be isolated by the conductor casing. The proposed injection pressure and anticipated injection pressure is way below the fracture pressure of both reservoir and Caprock. And then, as I mentioned, and as you can see from the earlier slide, that 3-D seismic data gives us a very good sense that we are dealing with a closed system.

Q. And could you go to the next slide, please. These next two slides summarize what you have deemed to be the key elements of Frontier's application. Is there anything you would like to add to the bullet points in the two slides?

A. No, that's fine. I think these slides basically summarize what are the key elements. One is that this AGI project has a substantial environmental benefit because it reduces greenhouse gas releases due to the sequestration of

CO2 that would otherwise be released, as well it eliminates -- it doesn't reduce, it essentially eliminates all SO2 air emissions because we don't flare that acid gas anymore, except, as John mentioned, in an upset situation or during a workover or something like that.

Nearby oil and gas wells and nearby water wells are protected both by the well design and the geologic factors in the area. The 3-D seismic has given us a good ability to understand the reservoir, and its relationship to the surrounding wells. And then the C-108, I think, contains all the -- all of the information and details that the Division will need to be able to evaluate this application.

The contingency plan, as we mentioned, was submitted on May 10 for approval, and an updated plan will be submitted for review and approval prior to the initiation of injection. Adjacent operators and the BLM support the project, and all the operators and surface owners and affected parties have been noticed, and there are no objections to the project.

Q. And do you agree with Mr. Prentiss that there will be economic benefits realized if Frontier's application is approved?

A. Clearly there will be because it will allow them to take gas that they are not being able to take now, even within their existing permitted throughput rate, they are not able to take that gas because they can't go above 5 tons per day flaring. And then with the added need, obviously the operators in the area are going to bring another 90 million cubic feet on line in the next year. The ability for them to get that gas to market will allow -- will provide an economic benefit as well, both to the state and to those producers.

Q. And, in your opinion, will the proposed injection of H_2S and CO_2 be protective of human health and the environment?

A. Yes. In fact, I want to reiterate, this has been a real pleasure working with Frontier, because even though, from a strictly economic point of view, while this is a good project, the Southern Ute Tribe which owns Frontier is very in tune to environmental concerns, and they are really committed to reducing greenhouse gas emissions, and this project is a part of that plan, really. So it will protect human health and the environment and enhance air quality.

MR. LARSON: At this point, Mr. Examiner, I move the admission of Frontier Exhibits 4 through 6.

EXAMINER JONES: Exhibits 4 through 6 will be admitted.

(Exhibits 4 through 6 admitted.)

MR. LARSON: And I will pass the witness to you.

EXAMINER JONES: I think we need to take about a ten-minute break.

EXAMINER BROOKS: Sounds like a real good idea.

THE WITNESS: Thank you.

(Recess taken.)

EXAMINER JONES: Let's go back on the record, and I'll make an announcement that is -- is --

EXAMINER BROOKS: He's not in the room, apparently.

EXAMINER JONES: Well, would it be okay with moving Number 17 and 18 to the end of the docket, also, Ocean?

MS. MUNDS-DRY: Sure.

EXAMINER JONES: We are going to take case 14642 before cases 14669 and 14667, but that's -- that's -- everybody knows that.

(Continued testimony of Alberto Gutierrez.)

EXAMINER JONES: Okay. So we are back on the record in Case 14664, and this is -- I appreciate what you showed, and it was very thorough, and I -- I like that. And I have just a few questions, and they'll probably be real easy for you to answer them.

THE WITNESS: Hopefully.

EXAMINER JONES: The guy you talked to in District 6 --

THE WITNESS: Yes?

EXAMINER JONES: -- who was that

THE WITNESS: James Yarbrough. And I can send you, after this, if you would like, Mr. Hearing Examiner, I can send you copies of that correspondence with them. But, you know, one of the things is they've got an FAQ on their GHG website, "Frequently Asked Questions," and after this question was raised by us in early May, I suggested to Mr. Yarbrough -- he is in charge of the whole GHG reporting for Region 6 -- and I suggested to him that he comment to headquarters that maybe they should put this question on the FAQ of what the status of Class 2 wells would be relative to those rules because I'm sure it's something that a lot of people are concerned about.

EXAMINER JONES: The reason I'm asking is because if we're going to be -- if quarterly reporting is going to be required, then Daniel Sanchez is our -- our coordinator for New Mexico, so I don't know if he knows about it yet. I'm sure he will be -- he will be told.

THE WITNESS: I think that the, you know, in terms of who that -- I think the reporting is going to go to Region 6, but I think that the Air Quality Bureau at ED has been kind of spearheading the whole GHG reporting rule because it doesn't just apply to these kinds of facilities, it applies to all kinds of facilities.

EXAMINER JONES: Okay. That might not be good for us. The 2 million a day for 30 years, is that connected in any way with NMED? In other words, do they want some kind of language like that in -- in this permit?

THE WITNESS: No. The 2 million a day is what

Frontier has determined to be the maximum amount of TAG that they would produce even under the plant expansion, but, as of right now, the plant is permitted through NMED for two kinds of maximums, one is a 60 million a day throughput, and then a 5 ton per day SO2 emission, and it's either/or, you know. So, in other words, the problem that Frontier is running into now is that because of the changing nature of that inlet gas, they would hit the 5 tons a day level and would hit it before they go to the 60 million that they are already capable of throughput. So they have had to ratchet back their throughput to about 54 million to stay under that number. But when the acid gas well replaces the flare, then that is no longer an issue, and they would be able to immediately go to their 60 million. And then, when they upgrade the plant for expansion, that would add another 50 million, and that's where the additional million of TAG would come from.

EXAMINER JONES: Okay. Thank you. And there's no -- there is no plans for including water in with the CO2 and H2S.

THE WITNESS: That's correct. This is a dry gas injection.

EXAMINER JONES: Okay. It looks like the notice was worked out beforehand and no unleased minerals, and MBH stated that, and they noticed all of the -- all of the lessees, surface owners, business owners, and that's all in

Appendix D.

THE WITNESS: It is. And just the one to add to that, even though it's duplicative, is, of course, the operators were noticed as well, although, obviously, the two operators in the area are also leaseholders, so --

EXAMINER JONES: Okay. Those -- the depths of the Lower Wolfcamp, you just stated they were 9800 to 10,000. Is that correct?

THE WITNESS: Yes, sir. Approximately.

EXAMINER JONES: Approximately. So the word, "Approximately," needs to be in there.

THE WITNESS: Absolutely, because we haven't drilled the well yet.

EXAMINER JONES: Okay. Those two -- when you did the 3-D seismic, the two wells that you said tested wet in the Wolfcamp --

THE WITNESS: Yes.

EXAMINER JONES: -- were they Upper Wolfcamp, Lower Bone Spring Wells that tested, or were they in this algal mound.

THE WITNESS: They were in the algal mound area, the Wolfcamp area, and the immediate vicinity of the plant. Let me tell you specifically which two of those -- which are those two wells because you can find the information in Appendix C for those two wells, but let's see, I've got them -- and also it's in a table in the -- okay.

If you look at Table 3 in the C-108, I don't know if you have that, but Table 3 on Page 15, it shows the two wells are the Queen Bee 36, which is one that is actually within that -- that very corner of the reservoir that we were looking at. Let me go back to this map, and I will show you exactly where that well is. That's this one here. This is one of the ones that tested wet, and it's in this same reservoir that we are looking at. It is plugged. It was a dry hole, in effect, in the Wolfcamp. And then the other one is the Baish B Federal 02, which is right here just outside of that, and that also tested wet in the Wolfcamp, and that's a plugged and abandoned well as well.

EXAMINER JONES: Wouldn't those be a bit downhill of where you're going to drill?

THE WITNESS: This -- this one right here is pretty much on strike with where we are going to drill. This one is downdip, yes.

EXAMINER JONES: Okay. Okay. There's no -- there is no relation to what you see here in Dagger Draw, is there? In other words, is there any -- Dagger Draw, I think you would test those as almost wet, also, but you produce enough water you get some -- some -- so how --

THE WITNESS: This is a different --

EXAMINER JONES: How would this relate to that?

THE WITNESS: This is a different kind of reservoir than what we saw in Dagger Draw, but even though a lot of these wells that are in the area, only these two specific ones did we see drill stem tests and where they drilled to see if they could get production out of the Wolfcamp. But the rest of these wells that are in the area that penetrated the Wolfcamp, we have the logs, and there was no cross over and no indication of any hydrocarbons there.

But I'm certain that -- well, I'm not certain -- but in every case that we have had a concern that there is potential hydrocarbons and there have been BLM minerals involved, the BLM has requested that we -- when we get the drilling permit, the BLM has requested a copy of the logs so that they themselves can satisfy themselves there is no recoverable hydrocarbons in that zone, and we would anticipate doing that same thing here.

EXAMINER JONES: Now, this green outline, is that closure of a structure?

THE WITNESS: It's not a structure. What it is, it's essentially a depositional feature. I mean, it's like a debris apron, and then what happens is outside of that green line what you get is essentially a loss of that porosity. You basically get a very impermeable, finer grain, kind of micritic mud that envelopes that debris apron.

EXAMINER JONES: So you can see it?

THE WITNESS: Yes. Absolutely.

EXAMINER JONES: But as you go up -- are these two wells wet because of the no closure updip? Is that correct? I mean, is that what you would say? Or, why are they wet?

THE WITNESS: Well, I -- my sense is that they are wet because there's basically no significant -- in that immediate vicinity of that reservoir, there is no significant source rock that would be providing hydrocarbons to that zone, and they are, you know, even though the porosity and permeability decline away from where that green line is, you still -- there isn't any, you know, fixed closure that is a structural closure of any kind.

EXAMINER JONES: So there is no closure, and there may not be adequate source rocks.

THE WITNESS: That's right.

EXAMINER JONES: Okay. What depths would be the top and bottom of the salt out there? Do you have an idea on that?

THE WITNESS: Yes, sir.

EXAMINER JONES: Or should I --

THE WITNESS: I have it in the application. I don't know it off the top of my head, but --

EXAMINER JONES: If it's in there, that's fine, I can find it.

THE WITNESS: It is in there. The anticipated --

the salt is actually shallower than 3800 feet. The San Andres top is at 3880, in that area, followed by the Glorieta, the Tubbs, the Abo, and then the Wolfcamp. And those are on Page 10 of the application.

EXAMINER JONES: okay. Is -- is this Lower Wolfcamp you are talking about, is this algal, is it a mound-type or is it lenticular?

THE WITNESS: It's probably more irregularly shaped. It's probably a combination of algal mound and debris shuffing off of that Shelf margin.

EXAMINER JONES: And this is going to be perforated -- as far as you said, you wanted to test the -- you are calling it the Leonard?

THE WITNESS: The Lower Leonard.

EXAMINER JONES: You are not calling that the Bone Spring Leonard?

THE WITNESS: No. I mean, the local terminology there has been the Lower Leonard. It's above the Wolfcamp.

EXAMINER JONES: How would you test it?

THE WITNESS: Basically by looking at the logs when we drill the well.

EXAMINER JONES: Okay. But not perf or try to inject?

THE WITNESS: No. No. Absolutely. If we looked at the logs and it looked particularly attractive, then we might consider injecting into their -- but that would be only if the Wolfcamp would not, for some reason, prove out to be as good as we think it's going to be. Because, frankly, for the amount of -- of gas that Frontier wants to put away, the Wolfcamp is more than adequate to deal with that.

EXAMINER JONES: The -- what would be the top of the Pennsylvanian?

THE WITNESS: The top of the Pennsylvanian would be at about 9550, and that would be -- well, no, I'm sorry. The top of the Pennsylvanian would be about 10,000. It's just below the Wolfcamp.

EXAMINER JONES: And so that debris field wouldn't -- wouldn't go down into the Pennsylvanian or --

THE WITNESS: Not from what we can see on the seismic or the logs. We would be TD'ing into the top of the Pennsylvania there or essentially right at the base of the Wolfcamp.

EXAMINER JONES: And the two closest other salt water disposal wells, they are both Wolfcamp?

THE WITNESS: They are.

EXAMINER JONES: That would be Lower Wolfcamp?

THE WITNESS: Yes, they are. And one of them is this Federal B1 which is just at the -- you can see it right here at the edge, southern edge of that one mile area of review, and then the other one is located just down here.

EXAMINER JONES: Okay. Those, the deeper wells in the area of review, are they production from those -- the six that are still active, are they -- is any of them in the Devonian?

THE WITNESS: Yes. Well, the active ones, there is one in the Devonian. That's the MC Federal 06 Well, which is -- let me see, 06 -- right in -- right here in this area right here, that's a Devonian well. And this information, by the way, is also on Table 3, Page 15, and that well is point 68 miles from the proposed well.

Then there is a -- the MCA Unit 382, which is point 7 miles away from the proposed well, and that reached a TD of 9600 feet, so it was basically into the top of the Wolfcamp, but it's plugged back to the San Andres, and there is a plug diagram for that.

And then there is the saltwater disposal well, which is the Federal B1 that I mentioned. And at the -- right at the bottom of that zone, and then there is a Paddock oil well, it would be the MC Federal 07, and then a gas well, the MC Com 01, and that's in the McKey formation, and then there is another oil well, the Baish 12, which is plugged back to the Abo.

EXAMINER JONES: So Devonian and McKey, they must be on a structure --

THE WITNESS: Yes.

EXAMINER JONES: -- of gas?

THE WITNESS: Yes. That's right.

EXAMINER JONES: But that structure doesn't extend up past the Devonian Age?

THE WITNESS: That's correct. That's correct.

EXAMINER JONES: Okay. Is this a loss circulation area, the lower -- that algal --

THE WITNESS: No, it hasn't been, although I was surprised, frankly, to see, given the injection records, I was surprised to see how low the pressures were in there, but it hasn't been -- there is no indication it was a loss circulation zone in any of the information that we saw from the drilling of all of those wells.

EXAMINER JONES: But as far as designing your injection casing, are you not anticipating the need for a DV 2.

THE WITNESS: No, we'll probably use a DV 2, absolutely.

EXAMINER JONES: Just to make sure?

THE WITNESS: Yeah. And you know, interestingly enough, you will see it when you look at the -- the well diagrams, they don't seem to have had any kind of problem cementing across those zones there, so we have some pretty good data on the cement in general that they have very good cement, and most of them are cemented up all the way into the

Abo.

EXAMINER JONES: How did you know that Rustler had water in it?

THE WITNESS: Well, because it's a general -- it's not specific to this area, but I mean, throughout this general area, the Rustler and Dockham group does tend to have some water in it, and it varies in quality. In some places it's probably as low as 6,000 TDS, but most of the time it's like in the 10- to 12,000. It's not water you would want to be drinking too much.

EXAMINER JONES: But it's perched aquifers.

THE WITNESS: It's basically -- the perched aquifers are more the alluvial aquifers above those zones, so there is connate water in that Rustler and Dockham group, but, you know, further east towards Eunice and in that area, the water quality gets a little bit better in that zone. So there are some wells in it much further east, but not in this area.

EXAMINER JONES: Did Cimarex and COG have -- did they see this 3-D seismic? Did you guys do the processing of it, or did you just buy the seismic and do the processing and pay for the processing yourself?

THE WITNESS: We did, we paid for the processing and purchased the seismic. Now, the -- in a -- you know, the licensing rules associated with buying that data allow us to use it in this kind of a fashion, but we can't really share the actual data.

EXAMINER JONES: Okay.

THE WITNESS: They like to sell that stuff over and over again.

EXAMINER JONES: The plugging methods and the date of the six wells that were plugged -- were plugged back across the zone, were they plugged in the 40s or were they plugged recently with modern plugging?

THE WITNESS: There is a combination. The wells -- the wells -- most of them, from what I see, were plugged in the 1980s to the 2000s. They weren't even drilled until the late 50s, mid 60s, originally, with the exception of one, which is that Queen Bee 36 Well, it was drilled in 1948, but it wasn't plugged until 2004.

EXAMINER JONES: Okay.

THE WITNESS: And the others were plugged in the 70s, one 1993, one 1996.

EXAMINER JONES: Okay. And the concept of which formations they would isolate with the plug, what would you say you saw from looking at the --

THE WITNESS: Most of them were plugged up through the Abo and cemented all the way down. And then -- as I said, the details are in all of those diagrams. And then some of them from the Abo up, they pulled the production casing.

EXAMINER JONES: But not below?

THE WITNESS: No. The lowest one that had production casing pulled was from about 5,000 feet or so.

EXAMINER JONES: David, do you have questions?

EXAMINER BROOKS: No questions.

EXAMINER JONES: Okay. I think, unless you guys have anything else.

MR. LARSON: Actually, I have one follow-up question and one exhibit matter.

EXAMINER JONES: Okay.

REDIRECT EXAMINATION

BY MR. LARSON:

Q. Mr. Gutierrez, is it your understanding that if the division approves Frontier's application, Frontier will go to NMED Air Quality Bureau to obtain a new permit to flare?

A. Yes.

Q. Is that because the flare will basically be only used for emergency purposes?

A. Yes, that is correct.

MR. LARSON: The administrative matters, Mr. Examiner, I noticed on Frontier's Exhibit 5 that I inadvertently left off the signed receipts for the certified mail notices, and I would request permission to supplement the record with copies of those signed returns?

EXAMINER JONES: I will leave that to David.

EXAMINER BROOKS: No problem.

MR. LARSON: Would it be acceptable if I call it Exhibit 5A?

EXAMINER BROOKS: 5 is what?

MR. LARSON: 5 is the notice letters and return receipts. I just neglected to add on the signed receipts.

THE WITNESS: In fact, I have them up on the screen here. We have them all. It's just that they didn't get added to that exhibit.

EXAMINER BROOKS: I guess I will let you put an "A" on your exhibit numbers since you don't have that many.

MR. LARSON: Or I could call it 7.

EXAMINER BROOKS: 5-A is fine.

EXAMINER JONES: And presumably at the next hearing or --

EXAMINER BROOKS: Yes. When do you think you will have these? I mean, you are waiting for return receipts.

MR. LARSON: No, we have them. It's just a matter of getting the copies in the record. I could supplement this afternoon.

EXAMINER BROOKS: You can get it by Monday, anyway?

MR. LARSON: Absolutely.

EXAMINER BROOKS: There is no point in continuing the case. We will let you supplement the record and --

EXAMINER JONES: Well, is that it?

MR. LARSON: That's all I have.

EXAMINER JONES: Thanks, Mr. Larson, and we will take Case 14664 under advisement with the stipulation of the supplemented affidavit.

* * * * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. ______, heard by me on ______________.

______________, Examiner
Oil Conservation Division

REPORTER'S CERTIFICATE

I, IRENE DELGADO, New Mexico CCR 253, DO HEREBY CERTIFY THAT ON June 23, 2011, 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 _________ day of July 2011.

Irene Delgado

Irene Delgado, CCR 253
Expires: 12-31-2011