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

ORIGINAL

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

APPLICATION OF DAVID H. ARRINGTON OIL & GAS, INC., FOR COMPULSORY POOLING, LEA COUNTY, NEW MEXICO — Case No. 14497

Consolidated with:

APPLICATION OF MARSHALL & WINSTON, INC., TO CANCEL OPERATOR'S AUTHORITY, TERMINATE A SPACING UNIT, AND APPROVE A CHANGE OF OPERATOR, LEA COUNTY, NEW MEXICO — Case No. 14538

APPLICATION OF AGAVE ENERGY COMPANY FOR AUTHORITY TO INJECT, LEA COUNTY, NEW MEXICO — Case No. 14720

REPORTER'S TRANSCRIPT OF PROCEEDINGS
COMMISSIONER HEARING

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BEFORE: JAMI BAILEY, Chairman
DR. ROBERT BALCH, Commissioner
SCOTT DAWSON, Commissioner

December 8, 2011
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission, JAMI BAILEY, Chairman, on Thursday, December 8, 2011, 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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CHAIRMAN BAILEY: This is the meeting of the Oil Conservation Commission on December 8th, 2011, in Santa Fe, in Porter Hall.

To my left is Dr. Robert Balch, designee of the Secretary of Energy and Minerals and Natural Resources. To my right is Scott Dawson, designee of the Commissioner of Public Lands.

All three Commissioners are here, and so there is a quorum. Commissioners, have you had a chance to look at the minutes of the previous hearing?

COMMISSIONER DAWSON: I have.

COMMISSIONER BALCH: I have.

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

COMMISSIONER DAWSON: I'll motion.

COMMISSIONER BALCH: Second.

CHAIRMAN BAILEY: All those in favor say aye.

Then I will sign on behalf of the Commission and transmit them to the Commission Secretary.

On the docket we have several cases and deliberation of rulemaking concerning horizontal well rules. We have agreed to have the deliberations on the rulemaking to follow after we hear all three cases. So those of you who are here only to hear the deliberations for the horizontal well rule, it will be at least a full day, probably, or into the afternoon to hear the cases. So you may be excused, if you want to, and come back when you want to.

On the docket we have Cases 14497, which is the Application of David H. Arrington Oil & Gas for compulsory pooling in Lea County, New Mexico; and Application of Marshall & Winston, Inc., to cancel an operator's authority and terminate a spacing unit, and approve a change of operator, in Lea County, New Mexico. These cases will be consolidated for purposes of this hearing, and one order will be issued for both cases.

Do I have appearances for these cases?

MR. CARR: May it please the Commission? My name is William F. Carr, with the Santa Fe office of Holland & Hart. We represent David H. Arrington Oil & Gas, Inc., in these consolidated cases.

With me is my partner Larry Montano, who will assist me in the presentation of the evidence. We have four witnesses.

MR. BRUCE: Madam Chair, Jim Bruce of Santa Fe representing Marshall & Winston, Inc. I have two witnesses.

CHAIRMAN BAILEY: Shall we take the David Arrington case first? Have your first witness called.

MR. CARR: The 23rd

CHAIRMAN BAILEY: That concludes this case.

Shall we go off the record?

(A discussion was held off the record.)

CHAIRMAN BAILEY: The next case to be called is Case 14720, Application of Agave Energy Company for authority to inject, in Lea County, New Mexico.

Call for appearances

MR. LARSON: Gary Larson of the Santa Fe office of Hinkle, Hensley, Shanor & Martin, for the applicant, Agave Energy Company. I have three witnesses

MR. BRUCE: Madam Chair, Jim Bruce of Santa Fe, representing Kaiser-Francis Oil Company. I will have one witness.

CHAIRMAN BAILEY: Do you have opening statements?

MR. LARSON: I do.

MR. BRUCE: I don't, but I might respond to Mr. Larson's.

MR. LARSON: I will be brief, rather than short.

Madam Chair, Commissioners, Agave Energy requests the Commission's authorization to inject CO2 and H2S into Agave's proposed Red Hills AGI Number 1 well.

Agave is currently in the process of constructing a state-of-the-art gas processing plant to service and anticipate an increase in gas production in the area including the Avalon Shale. And Agave proposes to inject CO2 and H2S derived from the sour gas that it will process at the plant.

I have three witnesses to present today. The first is Ivan Villa, who's an operations engineer, who will discuss the Red Hills gas processing plant and gathering system. The second witness is Jennifer Knowlton, an environmental engineer, who will discuss air quality and H2S contingency plan matters. And our third witness is Alberto Gutierrez, a professional geologist who conducted an evaluation of the injection zone, aided Agave in the design of the well, and will address Agave's ability to safely sequester CO2 and H2S.

Mr. Gutierrez, who has extensive experience in evaluating potential reservoirs for CO2 and H2S sequestration, will demonstrate that he has identified an injection zone that is ideal for sequestering CO2 and H2S.

Agave's proposed injection will result in economic benefits, including relieving operators in the field from the financial burden of having to treat H2S at the well head. There will also be environmental benefits, as sequestering CO_2 will eliminate a significant amount of air emission, as Agave will have to vent the CO_2 at the plant if it's not authorized to inject it.

And Agave's application, the presentation we'll make today will establish that. Given the geologic elements and the design of the proposed well, Agave can safely inject CO_2 and H_2S as proposed in its application in a manner that will protect all water bearing and oil and gas producing zones.

CHAIRMAN BAILEY: Mr. Bruce?

MR. BRUCE: Very briefly, Kaiser-Francis has concerns about -- first of all. I'll take a step back. Injection is going to be into the Cherry Canyon zone of the Delaware Formation. There is ongoing development in this area that almost always requires drilling through the Cherry Canyon Formation. And Kaiser-Francis has concerns about not only the -- how the injected acid gas will migrate, but the size of the plume. And it is concerned about its future development, how it might affect wells that are drilled through the Cherry Canyon. And we will address those with our witness, Jim Wakefield, who will be here shortly.

CHAIRMAN BAILEY: Mr. Larson, would you call your first witness?

MR. LARSON: Certainly. Mr. Villa.

IVAN VILLA

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LARSON:

Q. Mr. Villa, will you state your full name for the record?

A. Ivan via.

Q. And where do you reside?

A. Artesia, New Mexico.

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

A. I am the engineering manager for Agave Energy Company.

Q. What are your responsibilities in that position?

A. Overseeing engineering and construction departments. I've also got some input on the day-to-day activities for Agave Energy Company.

Q. Would you briefly summarize your educational and professional background?

A. I have a degree in Mechanical Engineering from Texas Tech University. I was employed with Agave immediately thereafter. Been engineering manager for Agave since 2006.

Q. Have you previously testified in a Commission or Division hearing?

A. I have.

Q. Was that a Division hearing?

A. Yes, sir.

Q. And did the Hearing Examiner qualify you as an expert engineer?

A. He did.

MR. LARSON: Madam Chair, based on Mr. Villa's education and professional background, I move that he be qualified as an expert engineer.

MR. BRUCE: No objection?

CHAIRMAN BAILEY: He's so qualified.

Q. Would you familiarize the Commission with Agave Energy's business activities?

A. Yes. Agave Energy is a growing midstream company specializing in gathering, treating and processing and also marketing of natural gas in Southeast New Mexico. We currently operate about 2,000 miles of gathering pipeline, about 50,000 horsepower of gathering compression, and also operate five small processing plants in Southeast New Mexico.

Q. And do you have managerial responsibility for those processing plants?

A. I do.

Q. In the Division hearing in which you

previously testified, did that also include an application for approval of an acid gas injection well?
A. Yes. That was the Metropolis injection well in Eddy County.
Q. Was that application approved?
A. It was.
Q. Is Agave currently injecting into that well?
A. No, we are not. We are processing sweet gas at our David Draw facilities, so we're not required to inject at this time. But we are making preparations, including working over the injection well for future H2S that may be introduced into the plant.
Q. That involved the re-completion of the well?
A. Correct.
Q. Did that well recently appear on the Division's inactive well list?
A. Yes.
Q. Has Agave resolved the resulting Rule 5.9 compliance issue?
A. Yes, sir, there's an inactive well compliance order in place.
Q. And Daniel Sanchez has signed off on that?
A. Correct.
Q. Who prepared Agave's application in this case?
A. Geolex.

Q. Why did Agave select Geolex to prepare the application?

A. We had good work history with Alberto and Geolex. They provided all the consultant services for the work that was done on our Metropolis injection well. We felt comfortable, once we approached Alberto for the work on the Red Hills project.

Q. Did Geolex perform its work at your direction?

A. Yes.

Q. And did you delegate to Geolex responsibility for providing notice of the filing of the application and today's hearing?

A. Yes.

Q. Why is Agave requesting the Commission's approval to inject acid gas into the proposed Red Hills well?

A. As you mentioned earlier, we are currently under construction on the Red Hills facility. As soon as Agave decided to build the plant, we knew there was potential for H2S production in the area. So with tht, we proceeded to contact Geolex and move forward with the geologic survey and also the permitting of the Red Hills injection well.

MR. LARSON: At this point, Madam Chair, I'd ask the Commission's indulgence. We have a

PowerPoint presentation that we would have set up if we would have gotten back sooner from lunch. Could we have a couple of minutes to set that up?

CHAIRMAN BAILEY: We'll take a 5- or 6-minute break.

MR. LARSON: Thank you.

(A recess was taken.)

Q. (By Mr. Larson) Mr. Villa, we're back on the record.

Could you go to Slide Number 4?

A. (Witness complies.)

Q. Go back one.

A. (Witness complies.)

Q. There you go.

Why is Agave Energy requesting the Commission's approval to inject CO2 into the proposed Red Hills AGI well?

A. For the potential for H2S delivery into the Red Hills facility.

Q. That will come at the point that the plant starts accepting sour gas?

A. Correct.

Q. Where is the Red Hills gas plant located?

A. In Section 13 of 24 South, 33 East. It's approximately 20 miles west of Jal, New Mexico, State

Road 128.

Q. And is the plant located on property owned by Agave Energy?

A. It is. We acquired 80 acres of property for purposes of construction of the facility.

Q. And is the proposed AGI well also on the same property?

A. It is.

Q. Why did Agave Energy make the business decision to construct the Red Hills processing plant?

A. With the increased activity in the Avalon Shale play, our parent company Yates Petroleum, along with some third-party producers that we provided services for in the past, have had some pretty successful completions of wells in that area.

We also felt there was a shortage of processing and treating capacity in this area, so we elected to move forward with construction of the plant.

Q. Would it be fair to say that Agave Energy wanted to get ahead of the curve of increased gas production in the area?

A. Yes.

Q. What is the current status of the plant?

A. The plant is currently under construction. We expect to have it online approximately March 2012.

Q. Is Agave constructing the plant and pipeline to the proposed well in accordance with the best available practices?
A. Yes. We have a standing EPC contract with BCCK Engineering out of Midland for construction of the facility and have also talked to multiple engineering firms that specialize in above-ground facilities for acid gas injection.
Q. And what's the initial design capacity of the plant?
A. 60 million cubic feet a day.
Q. When do you believe it will become operational?
A. March 2012.
Q. And what type of gas will the plant initially receive from the field?
A. Initially it will be a sweet gas stream with relatively high amounts of CO_2.
Q. How will you dispose of that CO_2 initially?
A. It will be vented to the atmosphere.
Q. Could you move on to the next slide, please?
A. Um-hum.
Q. Using this diagram could you briefly describe the process Agave will use to treat the sweet gas that it initially receives?

A. We've got a high pressure gut line, if you may, feeding the inlet side of the plant. We'll go through a pre-process stage to eliminate some of the heavier hydrocarbon components to increase the operability on our aiming system. But then the gas stream will be directed to the aiming area, where the aiming will then remove the CO2.

At that point, as we region the aiming, the CO2 will be vented to the atmosphere.

Q. Could you move to the next slide, please? When does Agave Energy expect to begin receiving sour gas from the field?

A. We've got a few wells that have been drilled in the vicinity of this facility. The issue we have right now is that those wells are located in areas where Agave does not operate any gas gathering pipelines. So we feel, as the drilling program ramps up and we extend our infrastructure, we estimate that probably within the next year to four years we'd be accepting H2S into the plant.

Q. If you could backtrack to the previous slide, please? Could you explain how the sour gas will be treated?

A. Sour gas is basically the same process, except for now the aiming will remove the H2S along with the

CO_2. We will then have a treated acid gas stream that we would look at injecting into the acid gas well.

Q. Is the pipeline from the plant to the well being constructed currently?

A. It is not. That would be the second phase of the project.

Q. If you'll move forward, please? When the Red Hills Plant goes online what volume of sweet gas do you anticipate receiving initially?

A. We estimate about 30 million cubic feet a day.

Q. Do you anticipate that amount will ramp up over time?

A. Yes. As the drilling program increases and we increase our infrastructure, we see that number ramping significantly.

Q. Does Agave currently have a plan to expand the plant's capacity in the future?

A. Yes, we do. As I mentioned before, we have 80 acres basically laid out to accept a second processing train, a second 60 million cubic feet a day processing train. And also our gathering pipeline to the inlet side of the plant has been designed for 120 million cubic feet a day.

Q. So the ultimate maximum design capacity will be 120 million cubic feet?

A. Correct.

Q. Is the maximum daily injection rate of 13 million mcfs stated in the application based on the ultimate 120 million cubic feet design?

A. That is correct.

Q. But initially the plant will not be accepting anywhere near that amount of gas?

A. No. Based on current data, we estimate about 8 million cubic feet a day, average, over a 30-year period.

Q. If the Commission does not authorize Agave to inject the CO2 and H2S derived from processing sour gas, how will Agave dispose of that acid gas stream?

A. The CO2 we would continue to vent to the atmosphere. The H2S would be a separate issue. We would then have to make a business decision on whether or not we want to accept H2S at this facility.

If so, we would require to producer to treat the H2S at the well head, which is, in our mind, not a very good or economical solution. With the amount of H2S that we see coming off some of these wells, it's just not profitable or economic to treat at the well head.

Q. In your experience, could that cost of treating the H2S in the field be prohibitive for operators?

A. Yes.

Q. In your professional opinion, will the injection of CO2 and H2S into the proposed Agave well result in a more efficient operation of Agave's gathering system in the Red Hills Plant?

A. Yes, without a doubt. From a safety and operational standpoint, we feel that treating for H2S and sequestering H2S at the Red Hills facility is much safer than going out and treating at each individual well head throughout the system.

Q. And will there also be economic efficiencies realized by the operators?

A. Yes. As I mentioned before, it can get pretty cost prohibitive to treat at the well head.

Q. In your opinion, will the proposed injection be protective of correlative rights, public health and the environment?

A. Yes.

MR. LARSON: I'll pass the witness, Madam Chair.

CHAIRMAN BAILEY: Mr. Bruce?

MR. BRUCE: Just a few questions.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Villa, if this is one of your other witnesses' area, please let me no know.

A. Okay.

Q. Now, you said the plant capacity will be 120 million a day; correct?

A. That would be the ultimate capacity, correct.

Q. Do you have any time frame on when that might be reached?

A. There's several variables. Right now all I can say is we're basically still monitoring to see what the drilling program is doing and just playing it year by year.

Q. That's the key factor, the rate of development of the reservoirs around this site?

A. Correct.

Q. Now, insofar as the approval of the building of the plant and the air quality permit, is that somebody else's job?

A. Correct. I'll defer to Jennifer for that.

Q. On this line here where you say, "Sour gas anticipated beginning in approximately one to four years," is that one year from now or one year from plant completion?

A. We would -- I would probably say one year from now.

Q. And so the carbon dioxide will initially be vented?

A. Correct.

Q. For how long a period of time after plant completion?

A. Until we begin accepting H2S into the plant.

Q. And that's indefinite at this point?

A. Correct.

Q. You mentioned economics or treating the H2S at the well head. Do you have any idea of the cost to an operator of treating the H2S at the well head?

A. Not at this time. We've looked at several different scenarios. That's going to vary based on H2S concentration and volume on the well.

Q. What's the range of that?

A. The range as far as?

Q. The cost of treating at the well head.

A. Really, I'm not prepared to give a number at this time.

Q. Have you estimated the cost of simply treating the H2S at the plant and just venting the CO2?

A. No, we have not.

MR. BRUCE: That's all I have, Madam Chair.

CHAIRMAN BAILEY: Mr. Dawson?

COMMISSIONER DAWSON: I don't have any

questions at this time. Thanks.

CHAIRMAN BAILEY: Commissioner Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. If you're qualified to address this, what's your anticipated client base? How many operators are affected by this plant?

A. Currently we've been talking to four to five operators, but we expect that number to increase as soon as the plant is online.

Q. Do you have any idea of the magnitude?

A. I don't at this time.

COMMISSIONER BALCH: That's all I have.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. Do you have an idea of the magnitude of the CO_2 that you intend to vent to the atmosphere?

A. I think that question would probably be answered by Jennifer, our next witness.

CHAIRMAN BAILEY: Then I have no other questions.

THE WITNESS: Okay. Thank you.

CHAIRMAN BAILEY: Redirect?

MR. LARSON: Nothing further, Madam Chair.

CHAIRMAN BAILEY: Okay. Your witness may

be excused.

MR. LARSON: Next I'll call Jennifer Knowlton.

JENNIFER KNOWLTON

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LARSON:

Q. Please state your full name for the record.
A. Jennifer Knowlton.
Q. And where do you reside?
A. Artesia, New Mexico.
Q. By whom are you employed and in what capacity?
A. I'm the environmental manager at Agave Energy Company.
Q. Could you please briefly summarize your educational and professional background?
A. I have a Bachelor's and Master's in Environmental Engineering. I have worked in the oil and gas industry for over 10 years. I'm a professional registered engineer in Wyoming and New Mexico.
Q. Where did you earn your degrees?
A. New Mexico Tech.
Q. Have you previously testified at a Division or Commission hearing?
A. Division hearing, yes, sir.

Q. And was that the hearing on Agave's application for the Metropolis AGI well?

A. Yes, it was.

Q. Were you qualified as an expert in environmental engineering by the Hearing Examiner in that case?

A. Yes, I was.

Q. And you've testified in other New Mexico administrative proceedings, haven't you?

A. I have testified several times in front of the Environmental Improvement Board.

Q. Including this morning?

A. Yes, sir.

Q. Were you qualified as an expert engineer in that case?

A. Yes, I was.

MR. LARSON: Madam Chair, I move for the qualification of Ms. Knowlton as an expert in environmental engineering.

CHAIRMAN BAILEY: Any objection?

MR. BRUCE: No objection.

CHAIRMAN BAILEY: She's so qualified.

MR. LARSON: Thank you.

Q. (By Mr. Larson) Does Agave currently have an air permit for the Red Hills Plant issued by the Air

Quality Bureau of NMED?

A. Yes.

Q. What does that cover?

A. We have an NOI, a notice of intent. The permit covers VOC sources and a small amount of nox and CO which is from the process here to be on location.

Q. And Mr. Villa testified at the initial stage of plant operations, any CO2 from the processed sweet gas will be vented. Are there any regulatory requirements addressing the venting of CO2?

A. At this time, there are no federal or state requirements addressing the volume of CO2. If we increase the volume significantly, we will have to apply for a federal permit per the tailoring rule, which is a permit for CO2. But at this time, it would be a shell permit. There's not going to be any requirements other than monitoring on it.

Q. Can you assist the Commission in understanding what the word "tailoring" means?

A. The Clean Air Act requires a PSD permit for any sources that are over 250 tons per year. When Massachusetts sued the EPA to require CO2 be a pollutant from motor vehicles, it kind of triggered some things happening under the Clean Air Act.

So CO2, if you have a facility where you have over 250 tons of CO2, you would have had to get a PSD permit. That basically means with CO2 that every single facility in the United States, including your car, would have to have a PSD permit. The states and EPA don't have the personnel to manage that many permits. So EPA passed the tailoring rule which adjusts those PSD thresholds for greenhouse gases, specifically for CO2.

Right now they're at 75,000 metric tons a year. Projected, I think, in 2014, to go down to 50,000 metric tons per year. But unlike other permits that have controls associated with them, there are no commercially available controls for CO2. So it would just be a permit that required monitoring of your CO2 concentration and reporting of that volume that you're -- and mass that you're submitting to the atmosphere to EPA and probably your state agency.

Q. And if the plant begins accepting sour gas with -- I'm sorry, H2S, would that implicate other air quality regulations?

A. Yes. There will be a significant number of state and federal rules, which then we would have to comply with, and before that happened, to get a new air quality permit that addressed those new regulations.

Q. And if Agave is not authorized to inject H2S derived from the processing of sour gas, how would it dispose of the H2S?

A. There are a couple of other control technologies available that I would not recommend as a business practice to Agave. We could probably process very small amounts that we could flare, but it wouldn't really be economical to process that small amount of sour gas. So we probably wouldn't process sour gas at this plant.

Q. So the onerous would go back to the operator in the field?

A. Yes, sir.

Q. If you were to pursue the flaring option, would there be limits on the amount you could flare?

A. There are limits on what we could flare. Even once we have an acid gas injection well, we would still have flaring as an alternative if there were to be a mechanical issue with the acid gas compressor or something like that. But New Mexico 20.2.35 limits the amount of sulfur that you can release into the atmosphere based on the amount of sulfur coming into your plant. It's basically 10 percent.

So we would only be allowed to flare basically 10 percent of the sulfur that we would release in a day. So there would still be limits, but we would be significantly curtailed in the amount of flaring that we could do.

Q. And in your opinion, will there be environmental benefits if Agave is authorized to inject the CO_2 and H_2S from processing sour gas?

A. Very much so. At 60 million standard cubic feet a day, which is what our plant is designed for, and that's what we will probably hold initially, 6 percent CO_2, which is what the engineers tell me our average is expected to be, that's approximately 68,000 to 69,000 metric tons of CO_2, so we would be able to inject that instead of venting it.

At 60 million standard cubic feet a day at 1,000 parts per million H_2S, which is what we have designed the plant for the blended gas at the inlet, that's approximately 422 pounds per hour of SO_2. If we were to flare all of that, which we couldn't do under the Air Quality Bureau rules, but that would be an equivalent of 1,850 tons per year of SO_2. And instead of putting that into the atmosphere, we would be injecting or sequestering that.

Q. The figure of 68,000 tons, is that per year?

A. Yes, that's per year.

Q. Will Agave Energy be in a position to obtain emission credits in the event that a cap in trade or similar greenhouse gas program is implemented in New

Mexico?

A. We would certainly advocate so. At this point, the Air Quality Bureau does not have written protocols for this. But I would expect that Agave would be at the table when those protocols are written, and we would certainly advocate for that.

Q. With regard to Agave Energy's existing Dagger Draw plant and the associated Metropolis AGI well, were you responsible for preparing and implementing the H2S contingency plan for the plant and the well?

A. Yes, I was.

Q. And has Agave submitted an H2S contingency plan to the OCD Environmental Bureau for Red Hills Plant and the proposed AGI well?

A. Not at this time.

Q. Has anybody spoken to the environmental bureau on behalf of Agave regarding the timing of submitting the plan?

A. Mr. Gutierrez has spoken to the Environmental Bureau about the timing of the submittal of H2S contingency plan, and it wouldn't be submitted until we were a lot closer to having a date where we could accept sour gas into the plant.

Q. Do you anticipate that the plan for the Red Hills Plant and well will be similar to the plan for the

Dagger Draw plant?

A. Yes, sir. It took us about nine months to come to an agreement with the bureau on the H2S contingency plan for the Metropolis. But they have approved, and it's a very good template. So we would be using that plan as a template for the Red Hills, adjusting, of course, for location a different area of influence for concentration, things like that. But the bones of the contingency plan would be the same.

Q. And it's somewhat different in the sense that the Metropolis well is on a different property than the Dagger Draw?

A. That's correct. It's on a state lease. There's about a half a mile of pipeline in between the plant that goes under the county road to the Metropolis injection well. Whereas at Red Hills, it is all on the same location.

Q. Will Agave obtain Environmental Bureau approval of the plan before it would inject any H2S into the proposed well?

A. Yes, we would.

Q. Is Agave agreeable to making that a condition of Commission approval of the application?

A. Yes, we would.

Q. And in your opinion, will Agave's proposed injection of CO2 and H2S be protective of human health and the environment?

A. Yes, it will

MR. LARSON: Pass the witness.

CHAIRMAN BAILEY: Mr. Bruce?

MR. BRUCE: Just a few questions.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. I want to confirm whether it was the approvals to construct the plant or the air quality permit, there's absolutely no qualification in those approvals regarding venting of CO2?

A. That's correct.

Q. And if I have these figures wrong, please correct me. But you're talking about 68,000 tons per year of H2S?

A. 68,000 metric tons of CO2.

Q. Of CO2?

A. Yes, sir.

Q. Is that at the maximum plant capacity?

A. No. That's at the 60 million capacity. You would double that, for 120 million.

Q. And I didn't catch Mr. Larson's -- one of his last questions to you. But you said for H2S injection, you need NMED approval?

A. For sour gas processing, I would need NMED approval.

Q. Did you do any economics for treating H2S only at the plant in combination with venting of CO2?

A. In general, it's not economically feasible. But in this instance, we did not do an economic analysis to separate those two components in the acid gas stream.

Q. And finally, regarding cap and trade, are you aware of any pending legislation in the United States Congress regarding cap and trade?

A. There's several bills that are in committee in the United States Congress.

Q. What are the chances of those passing?

A. You're asking my personal opinion, and I prefer not to answer that.

Q. Well, with the current makeup of Congress, don't you think it's highly unlikely that anything like that is going to pass?

A. One would hope. But there's two rules in front of the Environmental Improvement Board which address New Mexico only cap and trade. Those are a far more imminent concern to our company.

MR. BRUCE: I think that's all I have, Madam Chair.

CHAIRMAN BAILEY: Mr. Dawson?

COMMISSIONER DAWSON: I do have a few questions.

EXAMINATION

BY COMMISSIONER DAWSON:

Q. Your Dagger Draw and Metropolis injection well now, what are the rates that you're injecting into that well now; do you know or is it in operation?

A. Currently the well is not in -- we're not injecting. As Mr. Villa stated, we're doing some workover work on that well, and we anticipate injection in mid February.

Q. Does your plant at the Dagger Draw -- have you pretty much completed your plant, building your plant there?

A. That was an existing plant that we purchased in 2002. I'm sorry, it was the 2003/2004 time frame that we purchased that plant. We made some improvements and modifications. And actually we're currently investigating the economics of expanding that plant.

Q. So there is current processing ongoing on that plant?

A. Yes, sir. We're currently processing about 40 million of sweet gas through that plant right now.

Q. So the stream coming from the plant, what are you currently doing with the stream from the plant from the Dagger Draw?

A. The CO2 concentration at that plant is much less. It's about one- to one-and-a-half percent CO2, and that's being vented.

COMMISSIONER DAWSON: No further questions.

EXAMINATION

BY COMMISSIONER BALCH:

Q. Besides Dagger Draw and this proposed site, how many other facilities does Agave operate?

A. We have a total of five processing plants. The Dagger Draw is one of them. We just brought online a new processing plant called Paladuro, which is south of Loving. We have processing near Roswell, east of Artesia and near Lovington. And then we operate -- Agave owns and operates 25 compressor stations, and Yates owns six compressor stations in Dagger Draw of which Agave is the operator.

Q. Do you have an estimate of how much sour gas is processed in total?

A. I do not. Right now, Dagger Draw, there's sour gas in that system but that's being treated at the well head. So when we have our injection well operational in mid February, we will be taking sour gas at Dagger Draw. That will be 40 million standard cubic feet, but it will probably be around 300 to 350 parts per million H2S. We've got 7 to 10 million sour gas that's currently being treated at the Marathon Gas Plant. I do not know how much other sour gas that Marathon treats.

Q. I haven't been paying much attention to the EPA's greenhouse gas reporting requirement for the last few years, so I presume that you have. Are they still aggregating emissions by operator by basin?

A. They are for EMP locations. Now, gas processing, we're lucky in that our facilities are continued to be treated as individual facilities. So each of our facilities has to meet the threshold. But EMP is being aggregated by basin.

COMMISSIONER BALCH: That's all.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. As you know MIT tests are required for acid gas injection wells every two years. As the environmental manager, are you involved in developing training requirements on safety requirements for the testing of those wells every two years?

A. That would be our engineering staff and safety personnel.

Q. So you are not involved?

A. No, I am not involved. I may verify that

that's submitted just as a reporting requirement that it gets to the OCD in a proper time frame, but I would not be personally involved in developing the safety procedures for that test.

CHAIRMAN BAILEY: I have no questions.

Any redirect?

MR. LARSON: Just a couple of questions.

REDIRECT EXAMINATION

BY MR. LARSON:

Q. Mr. Bruce asked about NMED approval once the plant starts accepting sour gas. What would that approval involve?

A. The approval, the way that I would prefer to structure the permit, it would probably be about a nine-month process. So I would have to apply for the permission to treat sour gas and the associated emissions nine months before we anticipated doing that.

It would be a major permit revision. It would also throw us into a Title V, which means we have over 100 tons per year. So it would be a major undertaking to get the proper permits from NMED before we started processing sour gas there.

Q. Once you see a point down the road where you'll be accepting sour inlet gas, you would get that process going with the Air Quality Bureau?

A. I would hopefully in enough time frame that the engineers aren't waiting on me and my permits so they could start processing sour gas when they wanted to.

MR. LARSON: That's all I have, Madam Chair.

CHAIRMAN BAILEY: You may be excused.

MR. LARSON: I call my third witness, Mr. Gutierrez.

ALBERTO GUTIERREZ

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LARSON:

Q. Sir, could you please state your full name?

A. Alberto A. Gutierrez.

Q. And where do you live, sir?

A. I live in Albuquerque.

Q. What is the name of your company?

A. Geolex.

Q. And in what capacity do you serve with Geolex?

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

Q. Are you a registered professional geologist?

A. I am.

Q. In what state?

A. I'm a registered professional geologist in about 20 states.

Q. Did you prepare the application that we're addressing at this hearing?

A. Yes, my company and I did prepare it.

Q. Have you prepared other applications for Division or Commission approval to inject acid gas?

A. Yes, both.

Q. And specific to New Mexico, how many applications have you prepared?

A. Approximately eight.

Q. And have you prepared any in other jurisdictions?

A. Yes. In Texas, as well.

Q. And the applications you prepared in New Mexico, were they approved by the Commission or by a hearing examiner?

A. Both. Some were approve by hearing examiners and some were approved by this Commission.

Q. And were they all approved?

A. Yes, they were.

Q. And in the hearings on those applications, were you qualified as an expert petroleum geologist and hydrogeologist?

A. Yes, sir.

MR. LARSON: Madam Chair, I move for the

qualification of Mr. Gutierrez as an expert in petroleum geology and hydrogeology.

MR. BRUCE: No objection.

CHAIRMAN BAILEY: He's admitted.

MR. LARSON: Thank you.

Q. (By Mr. Larson) What authorizations is Agave requesting in its application?

A. As Jennifer and Ivan testified, basically Agave is requesting the authority to inject acid gas into the Cherry Canyon formation from a depth of approximately 6,200 to 6,530 feet.

That gas is anticipated to have a variable composition. As Mr. Villa stated initially, it will be essentially -- that TAG would be 100 percent CO2. But when the plant begins to see the likelihood of accepting H2S, that would be the time when they envision initiating injection as opposed to venting. At that time it's anticipated that that concentration would be 95 percent CO2, 5 percent H2S.

And we're asking a maximum rate of 13 million cubic feet a day. That would be at the 120 million cubic feet capacity for the plant. And that maximum operating pressure that we've calculated would be 2,085 pounds.

Q. Mr. Villa has testified that it will take, at this time, an undetermined amount of time to reach that capacity of 128 million per day. But yet you based your daily maximum injection rate on the maximum capacity?

A. We did. When we prepared the application, we took essentially the worst case, if you will, and that was assuming that the plant was at 120 million capacity from day one, injecting 13 million cubic feet a day of acid gas.

Q. Why have you included a maximum injection pressure of 2,085 psi in the application?

A. As part of the routine process for preparing an injection application, one of the requirements is to calculate what would be the appropriate maximum allowable operating pressure for injection into the well. And that is done basically using a very prescribed formula from the Division that we'll see later in the presentation, and that's the value that that formula yielded. But it protects the formation from being unintentionally fracked.

Q. And based on the fact that the injection rates would be ramped up over time, what do you anticipate will be the actual average injection pressure over the 30-year period covered by the application?

A. Well, the average injection pressure that we've anticipated would probably be based on all the reservoir data that we have. We anticipate a well head pressure of somewhere in the 1,200 to 1,600 psi range.

Q. So if I'm hearing you correctly, the 2,085 is well below fracking pressure?

A. Yes. By design, that's what the formula is intended to accomplish.

Q. Okay. And were you tasked with providing personal notice to all the individuals and entities entitled to receive notice of the filing of the application and the Commission hearing?

A. Yes, sir.

Q. And who identified the names and addresses of those individuals and entities?

A. We retained MLB Land Services, in Roswell, to do that work for us. And they identified both the surface owners as well as lessees and operators in the area.

Q. And what did you define as the area of review for purposes of determining who should receive personal notice?

A. Based on the policy of the Division and the Commission in reviewing these applications, we selected a one-mile area of review.

Q. Are lists of the names and addresses of the persons and entities entitled to personal notice included in the application?

A. Yes, in Appendix D.

Q. If I refer your attention to Exhibit Number 1, would you identify that exhibit for the Commissioners?

Q. Exhibit 1 contains copies of all of the notice letters that were sent out in August of -- August 30th, 2011, to both the operators, the lessees and the surface owners within the one-mile area of review. And it also contains the return receipt cards which were received from all of the people who were noticed, with the exception of one which we did not receive from Kaiser-Francis. But there is a copy of the confirmation from the U.S. Postal Service that it was indeed delivered on September 1st.

Q. Was notice of the filing of the application and the hearing also published?

A. It was. It was published in the Lovington Leader.

Q. Could you identify Exhibit Number 2?

A. That is the affidavit of publication of that notice of the original hearing. This was for the hearing -- this hearing, which was originally scheduled in September.

Q. And is that a true and correct copy of the affidavit you received from the Commission's clerk?

A. Yes.

Q. And I next direct your attention to Exhibit Number 3.
A. Yes.
Q. Could you identify that?
A. Exhibit 3 is a hard copy of the presentation that we are looking at today.
Q. The same PowerPoint slides we're seeing on the screen?
A. Yes, sir.
Q. Did you personally prepare the PowerPoint slides?
A. I did.
MR. LARSON: Madam Chair, I move the admission of Agave Exhibits 1, 2 and 3.
CHAIRMAN BAILEY: Any objection?
MR. BRUCE: No, ma'am.
CHAIRMAN BAILEY: They are so admitted.
(Agave Exhibits 1, 2 and 3 were admitted.)
MR. LARSON: Thank you.
Q. (By Mr. Larson) If you could move on to the next slide, please?
A. (Witness complies.)
Q. In the process of preparing Agave's application, did you take the injection fluid volume and composition and operating pressure into consideration?

A. We did. As we mentioned initially, the plant is going to be a 60 million capacity. But in fact, it probably will not -- when the switch is turned on, so to speak, the plant probably won't be getting but somewhere in the neighborhood of maybe 30 million a day, based on the estimates that we received from Agave's engineering group.

And so consequently, the design involves an initial injection of -- the slide says 2 to 5 million, but it's probably going to be more like 1 to 5 million cubic feet a day of CO2, only with the eventual introduction of H2S.

Now, it is likely that there won't be any injection until -- as Mr. Villa and Ms. Knowlton mentioned, there probably will not be any injection until there is H2S that is passing through the plant, so this initial CO2 only stream would be vented.

But it is anticipated that when the injection of CO2 and H2S begins, that it will have some variable composition from about zero to 5 percent H2S and 95 to 100 percent CO2. That's one of the big reasons why the acid gas injection well is such an important part of this plant, is because given the nature of the developing play in the Avalon that would be providing inlet gas to this plant, it's not really well known exactly how those wells are going to evolve in terms of CO2 and H2S.

So having the AGI gives a significant flexibility to the plant to be able to treat -- to be able to inject varying concentrations of H2S. Because an injection well isn't really sensitive to those changes in the way that other processing facilities would be. So that's what we anticipate.

The injected fluid, we looked at the compatibility of that TAG with the existing formation water, and we found that that's quite compatible .it's similar to what we've done and are doing in a number of other AGIs in the Permian Basin.

And lastly, we calculated the maximum operating pressure using the NMOCD guideline, and that calculation yielded the maximum pressure that we're requesting of 2,085.

Q. Could you explain what the acronym TAG means?

A. Treated acid gas.

Q. If you'd move to the next slide, please?

What criteria do you use for evaluating a potential reservoir for sequestering CO2 and H2S?

A. The first criteria really are -- I mean there's a whole series of criteria that we utilize that are weighed equally, but it's an iterative process.

The first thing we need to do is find a zone or a target that would allow the injected TAG to remain in a supercritical phase and that would allow for the injection of the anticipated volume of TAG at a pressure that would be consistent with safe operating practice.

Once we've identified those zones -- and in many cases there are numerous geologic units that may well meet that criteria. But then the problem is, are those units either currently or potentially productive in the area, and is the proposed injection going to interfere with either actual or potential future production? So we evaluate that and we try to rule and we do rule out zones that, in our estimation, could be possibly affected in a negative way that are either potentially productive or currently productive.

Q. Did you also look at existing wells within the one-mile area of review?

A. Absolutely. That's a critical component of that evaluation. We look at all of the wells -- actually, we start with a two-mile area of review. We look at all of the wells in that area, and then we focus down on the one-mile area of review. And in this area, there are only six wells in that area of review, one active and four plugged deep wells, and the one plugged dry hole in the Delaware.

And then what we do, once we've identified a zone that makes sense, we look at what portion of that reservoir and how is that reservoir going to be affected by the injection of the acid gas, and we calculate what is the best reasonable scientific analysis of that footprint.

And in this case, if we calculate based on the maximum case of 13 million a day for a period of 30 years, we got a radius of approximately half a mile at that maximum rate and about 520 or 530 acres that would be affected.

If we look at the actual ramp up of the anticipated inlet gas that was developed by Agave, what we actually are seeing is closer to a little under 8 million cubic feet a day over 30 years, as an average, and that results in about just under four-tenths of a mile radius.

Q. And in terms of this criteria that you evaluated, in your opinion are all these criteria satisfied with respect to the proposed AGI well?

A. Absolutely, yeah. And this slide is a summary of those criteria that we've been discussing.

Q. Could you briefly describe the methodology you used for determining what the footprint of the plume will be over a 30-year period?

A. Certainly. It's the same methodology that we have consistently used. Actually, it has evolved somewhat in the last seven or eight years of doing these kinds of applications.

But basically it is a cylindrical injection model that takes into account a conservative estimate for the residual water in the reservoir. Because obviously, the gas cannot displace that residual water. So effectively, the volume that is available to be injected into, is not simply a function of the porosity, but a function of the porosity and irreducible water concentration.

So we take that into account. We then calculate what the available volume is in the reservoir, and then we calculate what the total volume injected over that time period is going to be, and we determine what the radius is on that basis.

Q. And is that considered to be an accepted methodology among professional geologists?

A. Absolutely. Everyone understands that there are vagaries in the way in which a plume will actually develop in the subsurface when you do the injection. But given the data that are available when you do these kinds of applications and predictions, it's really the most defensible quantitative method for identifying what that extent is going to be.

Now, as you'll see in my presentation a little bit later, in some cases we qualitatively look at the reservoir and have an understanding that perhaps there are areas of higher porosity and permeability where the acid gas may extend more in those areas, or there might be some structural elements in terms of the formation that would affect also how that gas may -- and so sometimes qualitatively we will take that quantitative model and adjust it. But really that's the best approach that we have.

Q. I notice on your next slide you've listed five factors in your AGI evaluation. Yes, sir.

Q. Could you move on to the next one and tell us what your evaluation of land and mineral ownership and nearby development revealed?

A. Yes. As we mentioned, Agave purchased the 80-acre plant site which they are currently constructing the Red Hills Plant on. That 80 acres is located in Section 13 of 33 East and 18 South, and that location is where the plant is currently being constructed and where the well will be completed.

And then what we did was look at the surface ownership within a one-mile area. We have five private owners in this area. The bulk of the land is owned by the Madera Trust, and there are two small tracts within that one-mile area of review that are owned by the BLM. There's also one very small tract, just a couple of acres, that is a substation right adjacent to Highway 128 in the corner of the plant area.

Q. Could you go to the next slide, which is a more graphic representation of what you're explaining there?

A. Yes, this is the surface ownership. And as I mentioned, here is the location of the 80-acre tract that Agave has purchased for the plant. You can see in the northeast corner is where we located the injection well.

If we you went back to that other slide that Mr. Villa showed earlier, you could see most of the processing of the gas is taking place in this kind of west central portion of the plant, and then the pipeline for the acid gas goes along the north boundary and then over to the proposed injection well in the northeast corner.

All of these purple tracts here are owned by the Robert Madera Trust and, in fact, the bulk of the land surface is owned by them. There is this tiny little spot here adjacent to the plant site that is owned by Southwestern Public Service, and that is the substation.

Q. Has Agave received any feedback from the trustee or another representative of the trust regarding this application?

A. Yes. They're very supportive of the application. In fact, they have been working with Agave and providing aggregate and other materials for the construction of the plant.

Q. And could you point out to the Commissioners the boundary of the South Bell Lake Unit operated by Kaiser-Francis?

A. It's not shown all on this map, but the southern boundary would be along the base of Section 12, and then 7 and 8 here.

Q. And what did your evaluation of existing and potential production in the vicinity of the well reveal?

A. What we found is that there are basically several deep reservoirs that are either currently producing or anticipated to be producing in the vicinity, the general vicinity, I would say, of the plant.

Those are the Wolfcamp, the Bone Springs and the Atoka Morrow. Most of the deep activity is in the immediate vicinity of the plant, even though there really isn't -- there's only one active deep well within the one-mile area of review, that's a Morrow well. The remainder of the wells are all plugged, and most of those were also either Morrow or Atoka wells. And then there is one dry hole that was drilled back in the '60s for the

Delaware that never even penetrated this injection zone.

Then there are some wells to the south in the Bone Springs that are beginning to be developed, the so-called Avalon shale play, and those are down in this area. That's part of the reason for the construction of this plant, is to respond to that production.

Also shown on this map is the one-mile area of review, and the smaller solid circle represents the anticipated extent of the TAG if you were to calculate it at the maximum rate over 30 years.

When we kind of zoom in to the area of review, the one-mile area of review, as I mentioned, there are six wells within the one-mile area of review: Three are plugged Morrow wells, one is plugged Bone Springs well, and one is a plugged Delaware sand well.

The one active Morrow well is located just on the edge. I think it's actually .97 miles actually from the well, downdip of the -- located right here in the southern portion of that area of review.

Q. Did you analyze the plugging records for the plugged Morrow and Bone Springs well?

A. Yes.

Q. Have they been adequately plugged?

A. Yes. Those wells -- the plugging diagrams were included in the original application.

Q. Could you move to the next slide, please?

A. Sure. The next factor that we needed to evaluate was what is the local stratigraphy and the hydrocarbon production in the area.

Q. Excuse me. We've lost the --

A. No. That's part of my clever presentation -- not so clever.

Basically what I was wanting to say was that initially, this is the general stratigraphic section in that area. We basically have below the salt, which is the Castile Formation. We have the Bell Canyon Unit, which is the shallow Delaware production. Then we have the Cherry Canyon and Brushy Canyon. Below that we have the Bone Spring, the Wolfcamp, and then the Cisco, Pennsylvanian section that goes from Cisco to Morrow. And below that the deeper Mississippi and Devonian Units.

When you look at the production in this area within -- and I would say -- when we say "local production," we're talking about four to five miles away from the plant. Because as I mentioned, there's only the one Morrow well that is producing within the one-mile area of review.

But generally the areas that produce here are the Delaware sands or the Bell Canyon sands. We have some production in the Avalon, which is in this portion of the Bone Spring and the Wolfcamp there. There is some deeper production in the Atoka and Morrow. And then there are a few Devonian wells also in the area.

The reservoir that we selected is -- we kind of are sandwiching in in between this production into a zone in the Cherry Canyon below -- well below the productive units that are in the Bell Canyon. But that zone that we are looking at is roughly between 6,050 to about 6,500 feet.

Q. The third factor that you looked at in your AGI evaluation, did that involve the reservoir geology and the Caprock integrity?

A. Yes. Clearly -- I mean the whole idea of injecting this acid gas and CO2 is sequestering it so it stays where you put it. And so it's very important to characterize not only the reservoir itself in terms of its depth, its thickness, its porosity, its permeability and its structure, in order to determine whether it's capable of safely taking the fluids. But then also it's important to analyze the Caprock of that associated with that reservoir and the ability of the rock below and above that unit to contain that gas. And we did that in this unit, and I'll go into that in a little more detail shortly.

We also -- and that is a key part of

demonstrating the protection of producing zones or potential producing zones and groundwater, is the geology, the structure and the integrity of the Caprock. Also, as we'll get into, the other factor is the design of the well. But those things work together to make sure you have safe injection.

Then we look at the estimated footprint based on the approval we discussed earlier which, in this case, the footprint is really estimated to be based on an injection rate of under 8 million standard cubic feet over 30 years.

Q. Could you next move on to your stratigraphic analysis which is part of your geologic evaluation?

A. Certainly. This is a well log where you can see the same stratigraphy that we were talking about earlier. Here is the top of the Rustler, the Salado, and then here is the Castile. And then right here at the bottom is the top of the Delaware, and you can see it's the very top of this Delaware sand that is the productive unit.

Then we have the top of the Cherry Canyon at approximately 6,050 feet, and top of the Brushy Canyon at about 7,400 feet. And the zone we're looking at injecting into is in this portion of Cherry Canyon, which is separated from the production above by almost 950 feet of interbedded tight siltstones and limey silts and some sandstones.

And then we get into these five discrete units within the Cherry Canyon that comprise our injection reservoir, and then below that, we also have some relatively low porosity and permeability zones, all the way through the Brushy Canyon, long before you get to the Bone Spring potential play and actual wells that exist in the Bone Spring here in the Avalon.

In order to look at the protection of the shallow production, I want to emphasize if you look at this section of the Cherry Canyon, the yellow is the area where we anticipate injecting into our injection reservoir. This zone above it is a zone that is characterized by a series of interbedded siltstones and limestones and shales with some sand, but it's over 900 feet thick between there and the production, which is immediately under the top of the Delaware there.

There is no Delaware sand production within one mile. As a matter of fact, there's been a well drilled not very far from the existing -- where our proposed location is, and that well was dry in the Delaware. It was a dry hole.

CHAIRMAN BAILEY: Is this a good stopping point?

MR. LARSON: I believe it is, yes.

CHAIRMAN BAILEY: Shall we take 10 minutes?

MR. LARSON: Sure.

(A recess was taken.)

CHAIRMAN BAILEY: Back on the record.

Q. (By Mr. Larson) Mr. Gutierrez, could you continue with the specifics of your evaluation of the Cherry Canyon?

A. Yes. I'll try to keep it as brief as possible, because all this information is detailed in the application.

But this is a blowup of the closest well log that identifies the zones that we anticipate injecting into. There are five clean sands with an average porosity of about 19 percent. And there's some good data to map these across the site, and I can show you how we've done that a little bit.

As I've mentioned, we take the residual water into consideration using this equation. We determined that the residual water in that area is approximately .54. And based on that, we've got an available -- even though we've got about 18.9 porosity, we have only available a little less than 9 percent porosity in the injection zone itself.

The next thing that we look at is the structure in the area. You can see from this map, which is a structure map on top of the Cherry Canyon, that it's essentially flat across the area. Three are 20-foot structure contours, and you can see that it's essentially flat across the area.

Q. Quick question. In your opinion, is there any evidence of faulting in the area?

A. There is none. This is an east/west cross-section across the area. You can see the sands are fairly -- you can map them across. Although it is clear from the depositional environment that they may vary somewhat in terms of their porosity and permeability, but generally they're able to be mapped across the site.

And similarly here in the north/south cross-section, I know that it looks steeper than it is, but remember we have a vertically exaggerated cross-section. Otherwise, this thing would look flat as a pancake. You can see this is -- the only area where there is Cherry Canyon production is 250 miles away from this well, and it is in this area.

There are -- in our evaluation of the Caprock, there are multiple confining beds both within the injection zones, these green zones, and then quite a few above them. I haven't shown the full height above them.

This is just to show the immediate ones within the injection zones.

When we calculate, what we do is we take a look at all of the wells in the area where we can get pressure information from. I have to apologize. In the application there was -- these same figures are shown in the application. Unfortunately, we got the captions reversed. The one that says, "Estimated temperature," it's actually the pressure graph. It's got the correct axes on there, but just make a note of that in the application itself.

Basically we take the pressure information that we have from drill stem tests, from production records in the area, and we look at what that is likely to look at so that we can determine approximately what kind of pressure we would see in the reservoir where we are in the zone that we are completing.

Similarly, we do the same kind of thing for bottomhole temperature, because these are two factors that are critical in determining how much space in effect that TAG is going to occupy once it gets into the reservoir. In this case, we have a pressure of approximately 2,600 psi from the earlier graph, and a temperature in the range of 110 to 115 degrees that we anticipate in the reservoir at this location.

Q. Mr. Gutierrez, what conclusion did you draw regarding the net porosity of the proposed injection well?

A. Just under 9 percent in terms of effective porosity that we could use.

Q. You've already testified regarding the methodology you've utilized for calculating the total area to be affected by acid gas injection. How did you apply that methodology specifically to the proposed Red Hills AGI well?

A. As I mentioned, we have temperature and pressure that we got from the data that I just showed you. We looked at the ramp-up rate versus the maximum rates, so that we calculated both the maximum extent -- and that's what we included in the application. And subsequent to that, in response to some of the concerns expressed by Kaiser-Francis, we also looked at trying to show what the most realistic picture would be in terms of an actual injection rate over time.

We then looked at the irreducible water. We used this model of cylindrical distribution. As I mentioned, the very shallow dip results in very little opportunity for updip migration of the TAG plume.

And what we then calculate is we calculated what would be the amount of volume of the reservoir that would have to be filled in order for the plume to arrive at the southern boundary of Kaiser-Francis Bell Lake Unit. And when you do that, you basically see that after 30 years of injection, we've only used up about 35 percent of that aquifer -- reservoir volume. And consequently, we wind up with a safety factor of about 200 percent, just to even get to the boundary of that unit.

Q. The 200 percent, does that mean 65 percent of the reservoir is not going to have a plume?

A. That's correct. This map here is a map of the thickness of the injection zone. So what we know is that these sands get a little thicker in a kind of north/south trend. They've got these little pods that you can see just east of the proposed injection well.

And really we anticipate that in general, based on the behavior of the Cherry Canyon sands, that where, as the porosity increases, so does the permeability. So one of the things that we look at in terms of our qualitative assessment of what might happen to the shape of that plume is that in the direction of increased porosity, we probably have some increased permeability and, consequently, in this case, we've probably got some deflection that will happen to the east and slightly northeast.

Q. I was just going to say could you describe your calculations to arrive at the total area affected first by the maximum injection rates stated in the application?

A. Yes. That's what these four upcoming slides are going to show. This summarizes the data, the input into calculating what amount of the reservoir would be occupied and the radius that would be occupied.

Here we take a look at the conditions we were talking about of a reservoir temperature of about 112. We took kind of the middle number of the data that we saw, and the same thing for the pressure, about 2,600 in the reservoir, the average thickness, the average porosity, the irreducible water saturation, and then the net porosity in terms of number of feet.

Based on that, with a TAG that would be a 95.5 percent mixture, we would wind up with roughly 350 million cubic feet injected over the 30-year time period in terms of the volume that that TAG would occupy in the reservoir. That translates to about 520 acres and a radius of approximately a half a mile from the well. This is shown graphically on this slide, where here is the proposed well, and then this is essentially a half-mile circle around the well that would indicate that maximum area of injection.

Q. Did you also calculate the affected area based on Mr. Villa's testimony about the ramping up of plant production over a period of time?

A. We did. That's shown on this slide here. Basically, you'll note all of the other parameters are exactly the same, the TAG gravity, all of these reservoir parameters. The only thing that's different is the injection rate, the average injection rate.

So here at a little less than 8 million cubic feet a day, we wind up with a total volume in the reservoir of a little over 200 million, 210 million to be exact, occupying about 313 acres, and with a radius of about .39 miles.

One thing that's very important to remember, as is the case with all of these -- I mean it's a simple mathematical issue. But as the radius away from the well increases, for the same distance of increased radius, you have a much larger volume of reservoir available. It's just a function of the geometry of a cylinder.

So consequently, to go from a radius of say a tenth of a mile to two-tenths of a mile, you have a lot less volume that you have to fill than to go from say four-tenths of a mile to five-tenths of a mile. So that clearly affects the extent of the plume.

This, as I mentioned, you know, it is my opinion that the dip is not going to affect the geometry of the plume very much in this area, because over the area, the dip is nearly flat. And so what we feel is more likely to happen is that as you have a little more permeability towards the east in these thicker more porous and permeable sands, that we may get some elongation of that plume in that direction. But how far, it's very difficult to say. And I believe that the circular or cylindrical representation is the most defensible approach, given the data that we have.

Q. After Agave became aware that Kaiser-Francis had concerns about migration northward into the South Bell Lake Unit, did you specifically analyze the potential for a northward migration?

A. We did. As I mentioned, it's my opinion that the dip is not sufficiently steep there to make an appreciable difference in that migration in an updip direction. And in fact, as I mentioned, I think, if anything, we're going to have some elongation on an east/west trend.

But also, as I mentioned earlier, this is how we calculated that safety factor. We've got, like I said, the 210 million cubic feet of TAG in the reservoir over 30 years. That's another thing to emphasize. This is not like where it's going to go on day one. This would be ultimate size or volume in the reservoir after 30 years.

If you look at the volume in a .67 mile radius, and that .67 miles is the distance from the proposed well to the southern boundary of the Bell Lake Unit, you've got about 617 million cubic feet in that cylinder. Of that we're going to only use 209 million cubic feet, which is about 35 percent. And therefore, we have about a 200 percent safety factor there.

Q. In your opinion, is there any data suggesting that acid gas, particularly H2S injected by Agave, could impact any production in the South Bell Lake Unit?

A. No, either current or potential. This summarizes the data we were just talking about, so --

Q. In your analysis, did you also look at potential migration to water-bearing zones?

A. Yes. We always evaluate the potential effect on groundwater, as well as any surface water. There is clearly no surface water in the area of review, and actually for quite a while, except for maybe some isolated internally small lakes or stock ponds.

Then if we look at -- the only fresh water there we have is really in the Ogalalla and Dockum. And it gets progressively more saline as you get deeper, so a lot of this Dockum water is not very good. But certainly by the time you get into the Rustler, you're essentially in water that's greater than 10,000 TDS.

There are no water wells within a mile of the proposed well. This shows all the water wells within five miles. As I mentioned, as you'll see from the design of the well, we have multiple strings of casing that protect the groundwater in this area.

Q. In your professional opinion, will there be any impacts to groundwater by the proposed injection of acid gas?

A. Absolutely not.

Q. At this point, could you summarize the results of your analysis?

A. Yes. Essentially, we've got about 15 feet of net volume of reservoir that, after considering the irreducible water in the vicinity of the well, we've got good permeability that's anticipated in those zones. We've got a very good Caprock integrity, over 900 feet of these interbedded sands, tight shales and siltstones. We have no evidence of faulting.

The injection zone does not have any hydrocarbon shows. It has been tested in the area. It doesn't produce. There's only one deep active well in the area, four deep plugged and one shallow plugged well within the area of review. And most of those wells are outside of the anticipated acid gas plume after 30 years.

Q. Could you next address the well design for the proposed AGI well?

A. Yes. The design that was originally presented in the application was modified by an August 30th submission. And the only modification was really to actually increase the size of the production casing and the tubing, and also to increase the bore hole diameter, so that we could ensure a better cement seal between the casing and the bore hole, and also so that we could accommodate up to 13 million cubic feet a day of TAG.

So typically we use two and seven-eighths inch tubing and five-and-three-quarter inch casing. In this case, we're using seven-inch casing and three-and-a-half inch tubing. The tree and packer will both be Inconel on all of the bearing surfaces, all the acid gas exposed surfaces.

We will also have a subsurface safety valve set at 250 feet, also Inconel, and that is a slam valve that essentially -- like a flapper valve that will completely close in the event of any damage to the -- or catastrophic failure of the well head and, therefore, would not allow any of the acid gas that is in the well to come back up.

Also, we may use a choke in the packer to control the injection pressure. Because one of the things that we've seen is there are some saltwater injection wells several miles away, but in the Cherry Canyon in very similar units, that have injected very, very large volumes of saltwater under vacuum.

So one of the concerns that we have is the possibility that we would have to maintain a certain pressure in the tubing to keep the TAG in a supercritical phase. We won't know that until we drill the well and look at what we really see in terms of the unit, but we'll have that possibility and we may have to use that choke.

We also have the packer set in a corrosion-resistant casing joint, and from that casing joint, we will use cement, which is a special, very expensive corrosion-resistant cement, up to a level of about 3,000 feet, so that we isolate all of the productive units above that with that corrosion-resistant cement, and then we will use standard cement above that.

This is the diagram of the wellbore. You can see the upper casing here is essentially -- we'll have some surface casing to the top of the Rustler Formation to protect groundwater cemented to the surface. That's 20-inch casing in a 26-inch hole, followed by a 17-and-a-half-inch hole, where we will set an intermediate string that goes all the way to 5,190 feet, that will be into the Solado Formation to fully isolate all of those producing zones and all of the shallower zones in that. That will be cemented to the surface as well.

And then inside of that, we will have our production string, seven-inch casing, down to TD of 6,550 feet, with the packer set at approximately 6,170 feet. And then each of those sands we would individually perforate below that level.

As I mentioned -- I think I mentioned most of these already, but let me use this next diagram to show the general design of the AGI system. As Ivan showed on his map earlier, the AGI compression facility will be located in the northern area of the -- I mean the central western area of the 80-acre site. Then there would be a pipeline across the northern part.

This is just a schematic that would show where you have your aiming unit, you have an emergency automatic safety valve. You also have one on the upstream side of the compressor. Then you have downstream side of the compressor. You have this two-inch stainless steel line, which would be capable of -- would be rated for sour service and would be rated significantly above the maximum pressure that we would anticipate coming out of the compression facility.

And the tree itself will have surface pressure regulating equipment that would ensure that the well does not go above the maximum allowable operating pressure, and we have the subsurface safety valve at 250 feet. The tubing of the well is stabbed into the packer which is set in the corrosion-resistant joint, and we have the injection into Cherry Canyon.

Also important to note, we have the annular space filled with an inert fluid, diesel fuel or similar fluid, so that if there were tubing leaks, we could safely shut down the well and repair those.

Q. In your opinion, will the proposed well, as designed, protect all water bearing zones and oil and gas producing zones --

A. Yes.

Q. -- through the depth of the well?

A. Yes, sir.

Q. Could you next summarize the geologic and well design factors that you believe will ensure the integrity and safety of the proposed AGI well and the injection plume?

A. Yes. The geologic factors, we've discussed them all, but I'll review them. There are no faults or structural pathways identified in the area of review.

The Caprock is a thick -- 900 feet thick, an excess interbedded sequence of low permeability rocks, which will form a significant barrier above the injection zone. Similarly, we have that below the injection zone for almost 2,000 feet, before we get into the potentially productive Avalon.

Then we have a proposed injection pressure that's well below the maximum fracture pressure -- or the minimum fracture pressure of the reservoir and the Caprock. That's the geologic factors.

The well design itself, which we just went through the casing, will be set to protect surface water and potential production in the Delaware group. The safety features I've gone through, so I won't repeat all of those again.

But importantly. we have constructed quite a few of these wells in New Mexico, in Texas, and there are many others in Alberta, et cetera, that have been safely operating with this kind of design.

Q. In summation, could you summarize what you believe to be the key elements of Agave application.

A. Basically, I think the AGI project will have substantial economical and environmental benefits. The environmental benefit obviously due to the sequestration of CO2 that would otherwise be released to the atmosphere and of the elimination of the potential hazards and costs associated with treating H_2S at the individual well heads all over the area that would be served by the plant. So that's a primary environmental benefit.

The other significant economic benefit is, depending on how much H_2S is produced by these wells, it may even -- if the H_2S had to be treated at the well head, you could envision situations where a well that would otherwise be economically productive would not be economically productive if you had to treat that H_2S individually, the operator, at the well head, so that eliminates that potential opportunity.

It gives the plant an ability to handle varying concentrations of CO_2 and H_2S safely and allows for the maximum development of the potential resource in the area. That would result in some additional economic benefits to the state through additional royalties from production, employment and taxes associated with all of the activities associated with that production, development and the treating at the plant.

Also, the operators and all of the surface owners in the area of review have received timely and proper notice and, as I mentioned, the surface owners are very supportive of the project.

Also, to deal with the technical issues of the reservoir, the adequacy of the injection reservoir I think has been clearly demonstrated by the analysis and review of the available data. I think our application provides all the information necessary to evaluate and approve the installation of the AGI.

As was mentioned earlier, there is no H2S contingency plan yet, because it is anticipated that the plant will first be getting only sweet gas. Actually, it's not even a requirement of the AGI well itself. But really before the plant can even accept sour gas, the plant itself has to have this H2S contingency plan, Rule 11 plan and, consequently, the Rule 11 plan will be completed and submitted and we would obtain approval long before any proposed injection.

Furthermore, because the minerals -- this is unlike a number of the other applications that we've done up to this date. Because in this case, the minerals in the area where we are injecting are owned by BLM. So consequently, we have had to submit a parallel APD application to the BLM for this well, and that application has been deemed complete and approvable and is just in line with a bunch of other applications to be approved, we hope by the end of this year, by the BLM.

And lastly, I think we feel that the Bell Lake Unit is well protected because of the geologic and design factors and the extent to which the TAG will affect the reservoir.

Q. Based on all this testimony, Mr. Gutierrez, is it your opinion that the proposed injection will be protective of correlative rights, human health and the environment?

A. Yes.

MR. LARSON: Pass the witness.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Gutierrez, first question -- turn to page 10 of your Exhibit 3, just a couple quick questions.

The top of the Cherry -- I think you said the top of the Cherry Canyon is maybe a little above 6,200, but you will be injecting starting at 6,200 feet?

A. That is correct. We anticipate setting the packer at 6,170.

Q. Does the Division's limitation of .2 psi per foot of depth apply to the acid gas injection well initially?

A. Yes.

Q. So initially you wouldn't be injecting at anymore than 1,240 psi?

A. No. Because you have to calculate it based on the specific gravity of the TAG, and there is a correction to that formula that would be based on the specific gravity of the TAG. So actually the maximum allowable injection pressure is 2,085 based on that.

Q. What is the specific gravity of the TAG?

A. .79.

Q. This plant is being built because of the potential for future oil and gas development in this area, is it not?

A. Yes.

Q. It's the reason for the plant?

A. That is my understanding, yes, sir.

Q. Looking at your exhibit, page 17, you show some Avalon wells about roughly five miles, four miles, south of the plant?

A. That's correct.

Q. If you turn over to the next page, page 18, there's actually some closer wells, are there not?

A. There are. There are some -- these are -- I'm not sure whether these are wells that are yet complete or whether they're wells that are proposed. But yes, there are some Avalon wells closer.

Q. Okay. Those numbers next to them are the API numbers?

A. That's correct.

Q. So wells are being drilled closer than what you show on page 17? As a matter of fact, wells could be drilled up to the boundary of the plant, could they not?

A. Absolutely.

Q. If you turn to your pages 33 and 35, first page 33 of Exhibit 3, down at bottom, the volume you have, have you calculated how many barrels of fluid equivalent those numbers are --

A. No.

Q. -- for the 30 years of the life of the plant?

A. No, I haven't. It's a little difficult to do that, because you don't really have a sense of how the immediate area around the wellbore -- how quickly the temperature changes as you commence injection. So we found it better to calculate it in terms of the volume in mcf. But I mean you could approximate the barrels.

Q. I'm sure you have, I believe I've sat in on hearings with you, have you worked on regular saltwater disposal wells?

A. Yes.

Q. What is the typical final injection amounts into a saltwater disposal well? Are they 5 million barrels, 8 million barrels?

A. It goes all across the board. For example, in some of the wells that are injecting into the Cherry Canyon within, say, 10 miles of this area, there are some that are injecting 6-, 7,000 barrels a day of saltwater, and it just depends how long they run those wells.

Q. In this reservoir is there any danger of overpressuring the reservoir cue to these large injection amounts?

A. I don't believe so, not based on the maximum allowable injection pressure that we have calculated.

Q. Well you talked about well design. What type of treatment of the perforations will be done in the AGI well?

A. Typically, what we anticipate is that -- and what we have done in the past when completing these wells, is we just perforate, and then typically we do an acid -- we hit them with maybe 500 barrels of 15 percent hydrochloric acid to kind of clean off the skin from around the perforations. We don't always do that, but sometimes we do.

Q. But you would anticipate there would be some treatment?

A. I would anticipate at most there would be a slight acid job, yes.

Q. When you're talking about the injection, and there's -- on your page 23 you have five different injection zones in the Cherry Canyon. You highlight six zones, but you're only showing five for injection; is that correct?

A. Well, if you'll notice, they're labeled CC1, 2, 3 and 4 going up. That CC3 includes both of those little sands.

Q. Okay. Do you know what the permeability of these zones is?

A. We don't. I mean part of our program of drilling and testing will involve coring these, and we would take direct measurements of the permeability.

But based on the saltwater injection wells which exist in the Cherry Canyon in the general vicinity, we believe that there's certainly sufficient permeability to accept the acid gas that we're looking at.

Q. But you don't have a specific number at this point?

A. I really don't. I mean --

Q. That's fine.

A. I really don't.

Q. On page 25, you don't -- you testified about this. The injection zone does have about a 1 degree dip to the south?

A. That's right.

Q. On your cross-sections, it shows that these zones are continuous north/south and east/west?

A. They can be mapped -- the sands look the same and they're correlated across those. Now, as I mentioned, I think it's quite possible that there will be variability in porosity and permeability across these sands. But yes, we can definitely map them.

Q. You don't see any discontinuity between the injection well and Kaiser-Francis' South Bell Lake Unit?

A. No. I think ultimately there are sands within the injection zone that go up as far as the Bell Lake Unit, yes.

Q. If you'd move to page 32 -- first of all, is there a general correlation between permeability and net pay?

A. Well, I guess the best way to answer that is just what I testified to earlier. Generally the zones that have higher porosity tend to have a little bit higher permeability, but that's not always the case.

Q. Is the trend of this Cherry Canyon reservoir north/south or north/northwest, south/southeast?

A. It's kind of --

Q. North/northeast. Excuse me.

A. Well, in general that's -- I wouldn't call it the trend of the reservoir. The whole -- the Cherry Canyon is -- you could be misled by all of these colors, because all I'm trying to do is show differences in thickness. It still is across this entire area, but it's much thinner in the purple and bluer tones, and in the warmer tones is thicker. You can see the actual measurements based on individual wells there.

Q. Where the well is placed on the 80-acre plant site, is it positioned to access the better reservoir?

A. It's positioned to access the -- frankly, no. It will access a good portion of that reservoir based on the thickness beneath the overall Agave site.

But the determining factor on the actual location of the well was a consideration of what would be the safest and most appropriate location relative to the rest of the plant operations. Because we don't think that it makes that much difference in terms of the ultimate performance of the reservoir whether we've got another foot or two difference.

Q. Moving on to page 36, your estimation is that the fluids would migrate toward the thicker reservoir and better perm, preferentially?

A. I think the -- it's my opinion that the area that you see circumscribed by that dashed line would be the rough approximation of the 30-year plume.

MR. BRUCE: I think that's it, Madam Chair.

CHAIRMAN BAILEY: Commissioner Dawson?

EXAMINATION

BY COMMISSIONER DAWSON:

Q. Going back to Slide 25 -- the cross-section that you prepared with the producing well on it I believe is Slide 27. On Slide 25 is that farthest north well, that's the closest Cherry Canyon producer?

A. That's correct.

Q. Then on Slide 34, those wells in Section 25 to the south with the solid blue line, are those horizontal Bone Spring wells?

A. Yes, sir.

Q. Do you know what the production is on those?

A. I don't. I don't even know if those wells have actually already been drilled or if they're proposed wells.

Q. You're not sure whether that blue dot on top there -- is that the surface or bottomhole location; do you know?

A. That would be the surface location.

Q. So if those are fairly productive wells, wouldn't you assume an oil and gas operator or oil and gas lessee would maybe move to the north of Section 24 and drill a horizontal Bone Spring well on that section?

A. It's certainly possible.

Q. If they drilled a well on the north line of

24, which would be the south line of Section 13 where your proposed well is, and their surface hole location was on the north line, you wouldn't assume that that would affect that surface whole location going down into the Cherry Canyon, drilling through the Cherry Canyon?

A. It depends on when it was drilled versus when -- this area that is shown is only after 30 years of injection. So you could -- let's say that you drilled a well there tomorrow and operated it for 10 or 15 years, you might plug it even before the acid gas got there. So it just depends on the relative timing.

Q. On the exhibits with the receipts from the certified letters that you sent, as I look through those receipts, those green receipts for certified letters, did Kaiser-Francis not send one back? Because I don't see their name on there.

A. That's correct. If you look at that last -- that's what I was mentioning. There is a printout from the U.S. Post Office right after all of those green cards, and that is a track and confirm that shows that it was delivered to them on September 1st.

MR. BRUCE: Commissioner, we don't dispute that we received notice.

COMMISSIONER DAWSON: Okay.

Q. (By Commissioner Dawson) Did you do -- you looked at all the plugging records of the wells within the radius of the TAG?

A. Yes, sir.

Q. And did they have several plugs in them or did you look at --

A. Yes. And most of them had cement across the Cherry Canyon.

Q. And you looked at the cement bond logs?

A. Well, where there were ones, we did.

Q. And they had good integrity on the cement bond?

A. Yes.

Q. The well in Section 24 to the south, the south half of 24, is that a Morrow well?

A. Yes, sir.

Q. Is that still producing or do you know?

A. Let me see which one. I answered too quickly. I should have looked and saw which one you were asking about. Is it the one in the middle of Section 24.

Q. Yeah, in the southeast quarter.

A. Yes, sir, that is a Morrow well, and it is still producing.

Q. Okay.

A. That Morrow well is .97 miles away from our proposed location.

And just so that you have the clear -- we have provided a diagram of that well in our appendix to the C-108, along with the rest of the plugging diagrams, and that well is -- I can give you the specifics on it. It is -- I'm sorry, that well is an active Bone Springs well. It is not an inactive Morrow well.

Q. That's a vertical Bone Spring well?

A. Yes, sir. It is active. It's a gas producer. I don't know what kind of production it has. It's operated by EOG Resources, and -- you know, I'm not sure what zone it is producing out of currently, because it was drilled to a total depth of 15,600. And it started out as a Morrow well, so it may be producing strictly from the Morrow. But I noticed that -- I'd have to go back and look at the records to make sure.

Q. Okay. The proposed Agave AGI well, is that -- your 80-acre tract, or 79.69-acre tract, is that the southeast quarter of that section?

A. It's not the southeast quarter. It is -- I don't know. I don't have in my head the legal description. But my sense is that it is not quite the entire north/south distance of the southeast quarter, and it extends into the southwest quarter to some extent.

Q. Does it extend up into the northeast quarter of the southeast quarter?

A. I think it does, yes.

Q. It must, because the well location is 1,600 feet from the south line.

A. That's right. Yes, sir, it does.

COMMISSIONER DAWSON: No further questions.

THE WITNESS: I'm sorry. Just to go back, I just looked up this information which is in the C-108.

That well that we were discussing is operated by EOG Resources currently. It was originally drilled by Meridian. It produced from the Atoka 704 barrels of oil, 107,000 mcf of gas from '84 to '95, and it has produced a total of 54,480 barrels of oil from the Bone Springs and 107,000 mcf from the Bone Springs.

Q. (By Commissioner Dawson) It's currently producing from the Bone Spring?

A. The last records we saw were 2010, yes, sir.

COMMISSIONER DAWSON: No further questions.

COMMISSIONER BALCH: I have a couple of questions as well.

EXAMINATION

BY COMMISSIONER BALCH:

Q. What's your best estimate for the

supercritical pressure of CO2 at that temperature and depth to the best of your knowledge? I know there's no well there yet. What do you estimate that critical pressure to be?

A. With this TAG mixture, we'd have to be over about 1,200 psi to keep it supercritical.

Q. Do you have a sense of what the chemistry of the residual water in the Cherry Canyon is there?

A. I do. There is an analysis from a reasonably close by well that is included in our Appendix A of the C-108, and that is -- it was from an AGI -- I mean saltwater disposal well about six miles away. That was the closest that we had. The analysis is shown in the last page of Appendix A of the application.

Q. What's the approximate salinity?

A. The chloride is about 180,000, sulphate 1,240, hardness, 45,000.

Q. From what I can tell, your plume dimensions are based purely on volumetrics, just putting CO2 into empty space in the reservoir; is that correct?

A. They're based on displacing the displaceable water.

Q. The geochemical interaction of CO2 with saline water will have what impact on the plume, in your opinion?

A. Well, you know, if you look at the current research on acid gas injection, there's been -- we presented a paper just not too long ago in Calgary at the internal symposium. And there's been a lot of data and a lot work done on that chemical interaction. Obviously, it form as highly corrosive carbonic case acid and sulfuric acid if you've got H2S.

But what I find is that, in most of these injection situations, the actual mixing or chemical interaction that takes place, takes place at the front of that plume, and it's relatively limited, that most of the action is really just a pure displacement of that as a separate phase.

Q. I was considering trapping mechanisms, actually.

A. You're absolutely correct. One of the things that's been determined is that as you get into finer-grained rocks, you tend to have a more effective trapping of that injected CO2 than you do in more porous environments. So typically, this is one of the ideal kinds of environments for -- minimizing the migration is a situation where you have these interbedded sands and silts.

Q. When you do your testing, when you drill the well and test the Caprock formations, you do porosity permeability, do you also do capillary pressure and then further modeling of the simulation?

A. Yes, sir, we do. We typically would core both the Caprock and the reservoir, and we would do direct measurements of the residual water. We would also do both gas and water permeability. And based on that -- and porosity. And based on that, we would update our prediction.

COMMISSIONER BALCH: Those are all the questions.

CHAIRMAN BAILEY: I have several.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. I neglected to write down the page number where you refer to the water situation in the area. It's somewhere after page 11, I know that. But you refer to fresh water and 10,000 TDS?

A. In the Rustler formation.

Q. Yes.

A. Above that, in the Ogalalla, we have actual fresh water. The Rustler formation has -- in some places it has fresh water. In this area, it tends to be closer to over 10,000 TDS in the Rustler.

Q. Page 22 is probably an area -- but there is a large difference between fresh water and protectable water, isn't there, under state law?

A. Yes. I mean the water that is protectable would be water that would be less than 10,000 TDS.

Q. And that can be found as low as what, 1,900 feet in this particular area, a depth of 1,900 --

A. No. About 600 feet is the maximum depth of water that is below 10,000 TDS. The water in the Rustler in this area has been all over 10,000 TDS. Where we have fresh -- what we would consider protectable fresh water is really restricted to the Dockum group, the red beds and the Ogalalla overlying it.

Q. Which brings up the questions concerning the wells in the area of review. The first question is, the C-108 application, was that given to OCD, BLM? We don't have that here as part of our records at the Commission. You kept referring to an application.

A. Yes, ma'am. The C-108 application, as a matter of fact, was addressed to you as the Director of OCD.

CHAIRMAN BAILEY: So you only sent one copy and not six as exhibits for the Commission hearing; is that correct?

MS. DAVIDSON: I did not get six.

A. We've sent two copies. That's what we've always done. We'd be happy to send more in the future.

Q. If they're to be used for reference in exhibits, then the Commission is at a disadvantage not being able to refer to that.

A. Absolutely. I'm sorry, Madam Chair. If I'd been aware that you didn't have it, I would have provided additional copies.

Q. Looking at some of the wells in the area of review, you did not go into any detail here during the hearing so that the Commissioners could understand the situation for those -- particularly four wells that appear to be inadequately plugged.

The Simms Number 1, the cement top is 2- to 3,000 feet below the proposed disposal interval, and only internal cement plugs were placed so the annulus is exposed from approximate depths of 8,900 feet to the surface. The Government L Com Number 2 has unprotected open hole from 7,834 up to 5,500. That exposes almost the entire Delaware to the acid gas.

A. The plugging records show that the perforations in -- which well were you just referring to? Because I have them all in the appendix that --

Q. That we don't have. The Simms Number 1.

A. The Simms Number 1 has concrete -- I mean cement all the way through the Cherry Canyon Zone. I'd be happy to show you the plugging diagram which is in

Appendix B of the C-108 application.

MR. LARSON: Madam Chair, can I interject? I have another copy of the C-108. I believe what happened, when the application was submitted, that was before we knew the Commission was going to be doing the hearing. I think we assumed it was going to be a Division hearing. That's why we didn't submit six copies at the time. That's an oversight on our part. But I do have an extra copy.

MR. BRUCE: I would object to it. They should have submitted those for the hearing.

MR. LARSON: We assumed it was part of the administrative record.

THE WITNESS: It always has been, up until this point. We always sent them to the Division, and we've never put them back in as exhibits because they were always available before. I mean this one was sent directly to you, as the Division Director. I'm very sorry that we didn't send additional copies.

Q. (By Chairman Bailey) Because it was docketed for the Commission back in what, October, September?

A. Yes, ma'am. But this application was submitted in July.

Q. Yes. But you were aware back in September and October that it would be before the Commission?

A. Absolutely.

Q. So I will ask my questions concerning these four wells that are of particular concern to me.

The Simms Number 1, where the pipe was not recovered during the plugging of this well recently by Bobco, so the annulus is exposed from 8,900 feet to the surface?

A. Our plugging diagram, which we got from all of the cement records, shows that there is cement all the way -- from the Wolfcamp, all the way to the second string of casing, which is into the Delaware and all the way to the surface from there. And the details are -- I can certainly go through them all, if you like, on this particular well.

There is cement that was squeezed into -- starting at the bottom of the well from perforations at 14,750 to 17,770 feet in the Morrow, and that cement extended to the top of that zone. And there is a cast-iron bridge-plug within the well immediately above that zone.

In the next string of casing, it was perforated at 14,329 to 14,582, and cement was squeezed all the way into the subsequent casing that is at a depth of 12,228 feet. The zone above that, there was cement squeezed, and that was up to a total of 3,800 sacks of cement, all the way to the surface in that string. And then the other strings were the original cement that was in the intermediate and surface casing.

Q. The question is, is the annulus exposed from approximately 8,900 feet to the surface?

A. No, not to the best of our knowledge, based on the plugging records.

Q. Let's look at Government L Com Number 2. The question is, is there unprotected openhole from 7,834 up to 5,500 feet?

A. No. The bore is cemented from 12,800 feet to the surface in that bore, and it is cemented across the Cherry Canyon.

Q. Let's look at Government L Com Number 1. Is there unprotected annulus from 7,000 feet up to 5,450?

A. Yes. It appears that there is spotty cement from approximately 6,800 feet to about 5,400 feet.

Q. Let's look at the Smith Federal Number 1. Is there unprotected annulus from 6,450 up to 5,300 feet?

A. It's hard to tell. The information shows that there was cement squeezed at 6,900 feet with a 100 sacks, and then there was also cement spotted at 5,300 feet. I'm not sure exactly how far up that cement went.

Q. Change gears, separate question. You're not asking to dispose of produced water along with the CO2 and H2S, are you?

A. No.

Q. Has an API number been assigned to this well?

A. It cannot have an API number until the BLM approves the APD. When you have a well on BLM land, the State will not assign API number until the APD is approved. So we have submitted that and we're waiting approval.

Because when you do the APD process, you submit the C-102 to the State, but the State does not act on it because they've got an agreement with the BLM that they don't act on them until after an APD has been issued.

Q. And you do understand that we require MIT tests every two years?

A. Absolutely. That's the standard practice now in all of our AGI wells.

Q. You did discuss a subsurface automatic safety valve in the well construction?

A. Yes, Madam Chair. We included that in all of the AGI wells that we have ever designed and completed.

Q. On page 36, who is the mineral owner to the east?

A. The mineral owners to the east -- in fact, all of the minerals generally in the area are owned by the

BLM.

CHAIRMAN BAILEY: Those are all the questions I have.

Do you have redirect based on the questions that have been asked?

MR. LARSON: I have no redirect.

I would move the Commission to take administrative notice of the fact that the application was filed by Mr. Gutierrez with the Division clerk and, therefore, should be part of the administrative record in this case.

CHAIRMAN BAILEY: Any objection to that?

MR. BRUCE: Yep, I'd object to that. They should have presented it at the hearing. They should have presented it to us a week ago, according to Commission rules.

(A discussion was held off the record.)

CHAIRMAN BAILEY: They will be part of the record.

MR. LARSON: Thank you, Madam Chair. I'm finished with my direct presentation. I'd reserve the right to call a rebuttal witness, if necessary.

CHAIRMAN BAILEY: Are you through with your case?

MR. LARSON: Yes.

MR. BRUCE: I'm ready to proceed.

CHAIRMAN BAILEY: All right.

MR. BRUCE: I call Mr. Wakefield to the stand.

Madam Chair, I submitted to you what's been marked Kaiser-Francis Exhibit 1, which Mr. Wakefield brought yesterday. I don't need to submit it as an exhibit.

If you'd look at Agave Exhibit 3, page 17, there was a land plat showing wells in the area, and it's pretty compressed. And Mr. Wakefield prepared this. It covers basically the same area, and it just maybe gives us a better view of the entire area. And he may have a few comments on the plat. It does not contain any geological or engineering data.

MR. LARSON: I just received this copy from Mr. Bruce. I think if it's limited to being a demonstrative exhibit, I would not object to that use.

CHAIRMAN BAILEY: Only on that basis, as a demonstrative exhibit?

MR. BRUCE: That's correct.

JAMES WAKEFIELD

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence for the record?

A. James T. Wakefield. I live in Tulsa, Oklahoma.

Q. Who do you work for?

A. Kaiser-Francis Anadarko, LLC, a subsidiary of Kaiser-Francis Oil Company.

Q. What is your job with Kaiser-Francis?

A. I'm, for lack of a better term, a reservoir engineering manager for the Permian Basin.

Q. So for the Permian Basin. So you would be in charge of reviewing applications such as the one filed by Agave?

A. Yes.

Q. Would you please summarize your educational and employment background for the Commissioners?

A. I graduated from the University of Tulsa in 1972 with a Bachelor of Science in Petroleum Engineering; subsequent worked for Gulf Oil in Odessa, Texas, as a production engineer, reservoir engineer; and then Skelly Oil Company for two and a half years in Duncan, Oklahoma, and then as a reservoir engineer; and then a year or so with Getty Oil Company in Drumright as an area engineer; and then three and a half years with Grace Petroleum as vice president of engineering; and then three years with Lee Keeley & Associates as a consulting engineer; and since 1985, with Kaiser-Francis.

Q. You said you were, more or less, the engineering manager for the Permian Basin, including Southeast New Mexico?

A. It primarily encompasses Southeast New Mexico, Lea and Eddy Counties.

Q. During that period -- I'm just looking at your engineering requirements -- have you had a chance to review and even prepare your own geologic interpretations of areas of interest for Kaiser-Francis?

A. Yes.

Q. And were you responsible for reviewing Agave's application in this case?

A. Yes, I was.

Q. And did you look at that and compare it with your engineering knowledge regarding Kaiser-Francis' properties in the area?

A. Yes.

MR. BRUCE: Madam Chair, I tender Mr. Wakefield as an expert petroleum engineer.

CHAIRMAN BAILEY: Any objection?

MR. LARSON: No objection to his qualifications as a petroleum engineer.

CHAIRMAN BAILEY: He's so qualified.

Q. (By Mr. Bruce) And we have, like I said, what I've marked Kaiser-Francis Exhibit 1. Could you just briefly identify it for the Commissioners and then identify that big yellow blob in the middle of the map?

A. This is a production plat that shows the outline of the South Bell Lake Unit, which is a major economic investment for Kaiser-Francis, and the offsetting wells in about a four- or five-township direction around it.

On the plat is shown in color code the completion interval for the various wells. For instance, the Morrow will be -- a particular section of the Morrow will be yellow, the yellow blob.

And we've split it into some other zones for the first through the fourth. There are Devonian producers, Atoka, orange; Strawn, red; Wolfcamp, green; Avalon Bone Spring in a teal color; Bone Springs in purple, Bone Spring Sands; Delaware in pink; Mobil and Medanos zones in a different kind of purple and light blue; Lower Brushy Canyon in black; and the Cherry Canyon in gray.

Shown beside the wells you'll see, if they're producing, red and green numbers. The green numbers will be oil, and red numbers will be gas, with the daily production on top and the cume production on the bottom.

So if you look at the Madera Ridge 24 1 in Section 24 that was discussed before, it shows it produced from two different zones, one of which currently is the Bone Springs. It shows it producing 7 barrels of oil a day with a 15,000 barrels of oil cume, and 11 mcf a day of 107 mmcf cume. And you can similarly go through the rest of the wells.

For plugged wells, for instance the Simms Number 1 shows it is inactive from the second Morrow.

Q. In what section is the Simms?

A. It's in 13, within a one-mile circle from the acid gas injection well. And it was plugged in 1989, after recovering 654 million cubic feet of gas.

You can do the same thing for the Government L2 and Government L1 that we've discussed a minute ago, to the wellbore configurations.

Q. Again, in the Kaiser-Francis South Bell Lake Unit, they are the operator of that unit?

A. Yes. And our south lease line in Sections 12, 7 and 8, the closest point would be 3,700 feet to the proposed acid gas injection well, which is in the southeast quarter of Section 13, to be drilled 150 feet from the east line of Section 13 and 1,600 feet from the south line.

I've drawn in there what the Red Hills Gas Plant area would encompass. It's approximately 2,000 feet east to west and about 1,750 feet north to south.

Q. Now, before we get into specifics, could you maybe briefly identify Kaiser-Francis' concerns about the proposed acid gas injection well?

A. Yes, on a couple of levels. Our initial concern when we saw the application was the zone of injection. The Cherry Canyon is a zone that we, as well as anyone else in the area, will drill through in order to test any of the deeper zones that are currently being drilled for other horizontal development. There are several of those.

In the immediate area in Section 25, Yates and EOG are drilling horizontal Avalon Bone Spring tests. In Section 25 in the east half of the west half, EOG has drilled in the south the Federal 21H, and it is producing at 131 barrels a day and 513 mcf per day. It's already recovered 48,000 barrels of oil and 187 mmcf of gas.

Yates has an application to drill the Red Raider BKS State 3H in the east half of the east half, and it has drilled the Red Raider BKS State 2H in the west half of the east half of Section 25. And that well has been completed, but it's not producing very much. I don't know if it's being held back or what the situation is, but it's only producing 27 barrels of oil a day and 46 mcf a day.

If you go to the north, in Section 2 of 24 South, 33 East, you'll see that Concho has drilled one well, Macho State 2H, in the south half/south half of the north half, which is making 529 barrels of oil per day and 259 mcf a day. And they are getting ready to drill the Macho State 1H in the north half of the north half of Section 2.

There is additional Bone Springs and Delaware horizontal tests being proposed and drilled in Sections 15, 22, 21, 27, 28, 33 and 34 of 23 South, 33 East. We are making plans to drill similar tests in the South Bell Lake Unit.

Q. All of these wells that are being drilled, they're proposed below the Cherry Canyon?

A. Right. The Cherry Canyon zone is a target for injection. It's one of the highest porosity and perm zones within the Cherry Canyon Zone that does not produce. We utilize it for SWD.

Our SWD well is the KFLC Bell Lake Unit 230 in the southeast of the southwest of Section 30 of 23 South, 34 East, just immediately north of the north extent of our South Bell Lake Unit. We put about 7 to 10 million barrels of water in there from the Devonian and other zones.

Q. When you're looking at the development in this area, of course, as Agave said, they wouldn't be building this plant if there wasn't the planned development, substantial planned development in this area?

A. There is a substantial planned development. I agree with them. And there is a need for a natural gas processing plant.

Q. Most of the prospective zones that you identified are below the Cherry Canyon?

A. Correct. Cherry Canyon is 6,200 to 6,500 that they target for injection. It's ubiquitous. It's everywhere. It's hydrologically connected to zones that I have mapped in South Bell Lake Unit into the surrounding wells. In fact, in a conversation with Mr. Gutierrez and Lee Mazolo, we discussed that. And we came to an agreement that our maps look pretty much alike.

Q. And due to current modern drilling and completion techniques, are a lot of the wells being drilled now or are planned now wells that wouldn't have been drilled say five years ago or even a couple of years ago?

A. That's correct. The horizontal Bone Springs drilling program is just now getting underway.

Q. Let's address some specifics. The reason I mentioned that you look at a lot of geology and even developed your own, if you could look at page 32 of Agave's Exhibit 3, which is their geologic interpretation of the Cherry Canyon injection zone, do you have a problem with their mapping?

A. No. What they have done, and I think was pretty adequately explained, is they summarized the overall interval into net pay. This is net pay isopach map of that generalized interval.

Q. And do you agree that the reservoir is, whatever you want to call it, but is trending north/northeast from the acid gas injection well?

A. Exactly. In fact -- and he's shown that it thins -- on this plat that we're talking about on page 32, there's a thin in Section 12 immediately north of Section 13 extending north into Section 1 and over to the east into basically the west half and northeast quarter of Section 6 and the west half of Section 7.

Similarly, there's a like thin mapped in Sections 3 and 4 and 9 and 10 of 24 South, 34 East, which bracket where the trend of sand is headed, from the south to north.

Q. And in your opinion, what would be the preferential migration of fluids, based solely on this trend?

A. In my experience, the permeability typically lines up parallel with the trend of the sand.

Q. And would you agree that the better part of the reservoir would also have the better permeability?

A. Yes. They've shown the better part of the reservoir as primarily being this yellow zone, which, if you had the C-108, would show it to be about a 200-foot -- 175-foot contour.

It is the contour line that goes immediately to the west of the proposed acid gas injection well in Section 13. So it's the light yellowish-green color on your plat, if you have it in color.

And the color in the middle of that is a 200-foot contour line that may not be on your plat, that's on the 108, and the center-most is about a 225 contour line. So it gets thinner from the west, thicker to the east.

Q. And then if you look at page 25 of Exhibit 3, do you agree with Mr. Gutierrez's structural representation of the Cherry Canyon?

A. It matches mine.

Q. It is updip to the South Bell Lake Unit; correct?

A. Right, updip to the north. There's about a 400-foot fall from the center of our production in the Section 6 area down to the acid gas injection well that's proposed in Section 13.

Q. What is -- based on your experience, what would be the trend of the migration, based on that dip?

A. The major axis is going to be updip along -- parallel to the sand deposition.

Q. So now you've got two factors which would lead to a preferential migration toward the South Bell Lake Unit. You've got the better reservoir and you've got the structure?

A. Yes.

Q. Could you comment on the specific gravity of the carbon dioxide and the injection fluid?

A. In the C-108, Mr. Gutierrez, I believe, or Geolex, indicated that the specific gravity at the temperature and pressure in the reservoir is going to be about a .84. And that compares to about a 1.05 to 1.1 specific gravity for the fluid that's in the reservoir.

The Delta P or the differential pressure, the difference in specific gravity will cause the carbon dioxide to overrun the water. Since you've got a contained reservoir that's at equilibrium, when you inject into it, it has to find some place to go.

It's not like a depleted reservoir, where you're going from a high-pressure event, which would be your injection well, to a low-pressure event, which would be a producing zone. You're actually injecting into a stable equilibrium, so there has to be somewhere for it to go.

Initially, it will start out radially. But eventually the majority of it's going to go updip and it's going to go on strike with the sand trend.

Q. Then let's look at page 23 of Agave Exhibit 3 regarding these five Cherry Canyon zones. You don't disagree with Mr. Gutierrez on that, either, do you?

A. No, no. I think that each one of these sand lenses -- it's a cyclical deposition. You get a surge of sand because of the water level. The water level changes, and you get either a siltstone or a siltstone/limestone combination deposited on top, and then you get another change in water level, and you get sandstone delivered to the location and deposited, and it just repeats.

And this isn't a very -- on page 23 -- it isn't a very large document, so I may be misreading it. If you look at the very bottom lens, for instance, it's about 40-foot thick, with about a 40-foot-thick siltstone or siltstone/limestone combination above it. And then it's a much larger zone, a thinner zone, a thinner sand zone with another cap. So each one of them is capped. Rather than having 177 foot of pay in one cap, you have individual reservoirs, each with a cap.

The conversation with Mr. Gutierrez previously was that I was concerned that gas would overrun and congregate at the top. He assured me that was not going to happen because of these benches separating the various sand lenses.

But that raises the other problem. That due to them being each isolated, each one is going to have its own little gas cap created by gas injection or CO2 -- it's actually gas -- that's the wrong term -- carbon dioxide -- its supercritical condition is going to be a liquid.

But because of the gravity difference, it is going to be a plume, as Mr. Gutierrez testified. It's not going to have a lot of interaction. We've injected CO2 in reservoirs and we've drilled infilled MC wells, and we found that it stays pretty much as a plume with the contact interval being the point in time where you get mixing. And in the case of oil, it enriches it and pulls it out of the pore spaces.

When you're doing water, you're not going to have that same situation. It's going to stay mostly as a plume. And it's going to tend to start radially, and then it's going to tend to override -- rather than staying completely within the 40 or 60 foot of sand, it's going to go into the 40 foot of sand and then quickly, maybe 100 feet out or so, start coming up to then overriding and being congregated in the top 5 feet or so or maybe 10 foot of the sand.

So instead of having 177 feet of sand and having it all in the top 20 or 30 foot, you've got five or six lenses of sand, where each one of them is going to have a CO2 cap on it, a liquid CO2 cap on it, that's going to be concentrating the CO2.

What that does is it depreciates the calculation of net pay and enlarges the circle about which you're going to have your footprint. So I think that was my other concern about it when we talked to him, was that that the drawing of the circle and the geometry of defining a flow path based on the cylindrical model assumes many things that are not true with this reservoir.

The first thing it assumes is permeability is the same in all directions. Mr. Gutierrez admitted that it's going to be better to the east, where the thicker pay is at. So he admits it's going to be more football shaped than spherical.

In addition to that, the updip component, although only 1 degree, and Mr. Gutierrez characterized that as flat -- and I certainly agree it's flat. But if you'll notice in driving up here from Albuquerque or anywhere else you want to go, you'll notice the ground is typically flat. And all of a sudden then there will be a gash in the ground where water has found a low spot and started cutting through. And then offsetting it perpendicular to it are other little ravines coming in, and each one of those started out in a flat area. They're all finding the lowest point. Water seeks the lowest point to get to the lowest gradient.

The same thing is going to happen with the CO2. When it's injected, it's going to find the weakest path, and that is going to be vertical. And it's going to be updip, even if it's 1 degree. So maybe it isn't completely updip, but it's going to be substantially updip.

So I don't think you're going to see any problem with the wells to the south very much of this injection well. It's all going to be north and east. The south and west is not going to be an issue.

We've made a big case that it's a 30-year project to get to the amount of gas that we're talking about in the ground, and I don't disagree with that. I think it's going to take a long time to get there, but it's a lot of barrels.

With the maximum injection rate of 13 million a day, if we are as successful as I think we're going to be in the oil industry in drilling horizontal wells in this area, we're going to load the plant up. I've been involved in several of these kind of projects around different parts of the country, and we're always surprised by how fast we load the natural gas plant up. We build them, and we have to expand them. I think the same is going to be true here.

I think they're visionary in building the plant. My only issue is the zone they want to get rid of the acid gas in. It poses a problem for everybody who's going to drill around them, even in this lease. This particular lease is owned by someone. They're going to have to drill the wells.

As he said, as Mr. Gutierrez said, this is a very corrosive mixture. The carbonic acid that is formed by the mixture at the leading edge of the carbon dioxide plume in the water will be toxic and will be there forever. It's not going to go away.

If you drill into it -- and it's going to be pressured up more than the normal sands around it. It's about a .41 psi per foot gradient, based on his exhibit that showed the pressure versus depth, and I agree with that. And people typically drill through these zones with basically water, 8.33 pound per gallon, .433 psi per foot gradient. And it's going to take more than that to drill through these.

We have saltwater disposal wells in Oklahoma, Texas, New Mexico. We all know that when you drill around them, for some reason we didn't contain it into a cylindrical area, and we suddenly find a pressurized interval from it.

We found it at Bell Lake. We found that the water didn't go necessarily in a spherical area from our injection well. We found it in wells that are drilled a half a mile or more away, and it was a much less number of barrels than this.

The 7.8 million a day acid gas injection case for 30 years results, I think, in something like 27 million barrels -- 37 million barrels being injected. The maximum case is 62 million. That's a lot of CO2.

And we think, Kaiser-Francis, that being only 3,700 foot away from this well, the fact that we're updip and on strike with it in terms of sand deposition, that there's a high likelihood that somewhere down the road we're going to have to deal with this issue.

We are probably going to be drilling wells along our south periphery. And because we want to drill these wells as horizontal wells, we're going to want to go updip. And updip in this case means we'll put the wellbore at the southern edge of our lease and drill north. So we're going to be highly susceptible at 3,700 foot from the line to an acid gas injection possibility.

Q. If you have to drill in that situation, what extra costs would be incurred by Kaiser-Francis?

A. The first cost is going to be controlling the well. No one is going to want to drill through a CO2 zone and have it surface.

The second problem is going to be -- it's not going to be just the 50-foot or 30-foot zone that they're going to put a corrosion-resistant piece of casing in their injection up well. When you drill through this, you're going to have to put a 4- or 500-foot corrosion resistant casing in it to protect it after you get it drilled and use high-strain corrosion resistant cement in it.

Even if the gas plume isn't there yet, you're still going to have to do it because you know the horizontal well is going to last a long time. So you've got immediate costs, and then you've always got the risk of a casing leak.

Q. Okay. To summarize what you're saying, even though you're looking at page 23 and there's supposedly 177 feet of net pay, the acid gas injection, once you get a short distance from the wellbore, isn't going to be uniformly distributed through that 177 feet?

A. No.

Q. And that would lead to a much larger radius of injection plume?

A. Correct.

Q. In conjunction with being updip and the acid gas injection plume going upstream?

A. Yes.

Q. Let's move on to page 33 of Agave Exhibit Number 3. I think you touched on this. This is the maximum case scenario, and I think page 35 is what they project is the likelihood.

And you can pick either one, but did you do the calculation to determine what the cumulative barrels of injection would be in this zone?

A. I agree with Mr. Gutierrez. It's an esoteric calculation. We don't know the exact mixture and the exact number because of the variations in pressure and temperature.

But just utilizing the simple conversion that he did on this chart, where he has barrels of 5,692 and cubic foot of 31,957, that implies the standard 5.6144 cubic feet per barrel. Using that calculation, in 30 years of injection, you get 62,340,000 barrels.

Q. How would this compare with a normal saltwater disposal well? You mentioned some up in the South Bell Lake Unit.

A. We've had 30 years of injecting up there, and we've probably put in somewhere around 10 million barrels.

Q. So this would do substantially more injection?

A. Our injection pressure -- we have a new well up in our North Bell Lake Unit in Section 8 of 23 South, 34 East, which is off this map. It's a brand new well. It's not -- the reservoir is not pressured up, but our injection pressure typically runs 1,000 pounds for about 500 barrels of water a day.

Again, it's a situation where the zone is not being produced. It's at original pressure, which is about 26,000 pounds pressure. So to get water in the ground, we're actually injecting equivalent water so we don't have a gravity difference. So our water column is heavier than the water column for carbon dioxide.

And so our service injection pressures are going to be less for a given rate because of the difference in column pressure than it is for carbon dioxide. So the question was asked of Mr. Gutierrez earlier, and he correctly answered, that it may be 1,600 pounds. because he's going to have to add in the difference between water injection and carbon dioxide injection columns to get to the bottomhole.

And then it becomes the issue of rate versus what the reservoir can accept, and we don't know that yet. Mr. Gutierrez said he's going to -- his company, Agave, is going to -- and Yates are going to core it and find that out for us.

I would suggest that we take another look at what the injection pressures will be at the time he does that, because we may find the reservoir is tighter than we think, and you won't be able to get that much CO2 into the reservoir at the maximum calculated operating pressure, something like that.

So it could be they may run up against quickly if they get to this 7, 8, 10, 12, 13 million a day injection rate. As long as they're at the 1, 1-and-a-half, it's going to be no problem. They're going to be easily able to get rid of the water. It's when you get to the 5,000 barrel per day rate with 7.8 million a day to 13 million a day injection that you're going to run into problems with the injection pressure.

In which case, it begs the question of how the drilling of this well really helps them if they don't get enough injection rate that stays below the fracturing pressure for the zone of intent. So my concern is -- one of my concerns is staying within the fracture pressure limitations devised by the NMOCD, given the high rate of injection they're going to have.

Q. Would you request that the Commission deny approval of the acid gas injection well?

A. Yes, I would.

Q. Do you think they've shown that it's economically necessary?

A. No. The limited statement in the summary that the acid gas injection well would result in additional income through royalties being paid to the State of New Mexico and that it would employ additional people and taxes would be higher, all of that is related to the gas plant, not to the acid gas injection well. The acid gas plant has been approved.

The question is, for Agave and Yates -- and they didn't define it today. They didn't give us any information on costs. They didn't tell us what the injection well was going to cost. They didn't tell us what the cost was to treat small amounts of hydrogen sulfide at a well versus what it was going to cost for them to treat it at the plant, instead of injecting it, and how that cost comparison would result in even the need for an acid gas injection well.

And there was additional testimony by the end of the day that that final decision to drill the acid gas injection well has been made. But the final permit isn't going to be filed, and the well may be completely unnecessary if they don't get the volumes of H2S that they're expecting. I don't know what they're going to get in H2S. I can't tell you. It may be that the well never puts an mcf in the ground or a barrel in the ground.

But if things go the way they've stated, then I have a problem representing Kaiser-Francis over the next 30 years as to how that will affect us. And I'm concerned -- I don't know what this Commission is going to do or how they're going to see that. But I'm concerned that it's going to everybody who wants to drill around this well.

For instance, if we want to sell our interest in South Bell Lake and this is a cloud on our title, how do we deal with that? Do we get an indemnity from Agave and Yates that they're going to make up any difference or any problems with our wells?

We can promise, as Agave or Yates or

Kaiser-Francis, if we were making the application, I would probably make the same arguments he did. They're logical. Cylindrical is logical. The problem is that what's going to happen may be illogical, and we can't define it. Because we can't define it, it then affects everyone in the path of it.

And in our case, I think being updip, on strike and in the thick of the sand, we potentially are going to get there. You can make the argument that the thicker the sand, the smaller the radius is going to be. I don't quibble with that. I can make those calculations, and I have.

But there's still the opportunity to get there. And I've made calculations that would show that you can get there fairly easily with this kind of volumes.

But it comes down to the fact that not each one of us is going to know that answer. So we would want the Commission to look at it from the viewpoint, is the well necessary, number one?

Their permit isn't requiring it. It looks like they're doing it from a cash-flow standpoint to take advantage of the potential, which may never happen, of cap and trade, and I hope it never does.

So it may be a wasted expenditure, which waste is one of the things you're supposed to, in my opinion and I think in your charter, avoid. And the other is protection of correlative rights, which I think this threatens that.

MR. BRUCE: Thank you, Mr. Wakefield. I pass the witness.

CHAIRMAN BAILEY: It's 5:00. I think we should stop for the day and continue in the morning with cross-examination and questions of the witness. However, Commissioner Dawson won't be here until what, 10:00?

COMMISSIONER DAWSON: 10:00 or 10:30.

CHAIRMAN BAILEY: So we need to continue this case until 10:30 tomorrow morning.

MR. BRUCE: I don't have a problem with that. But let me talk with my witness for a minute, please.

CHAIRMAN BAILEY: Okay.

MR. BRUCE: That's fine. He did have some availability problems, but he'll change his schedule around for the Commission.

CHAIRMAN BAILEY: Mr. Larson, do you have major problems with that?

MR. LARSON: I'm conferring with my witnesses on their travel issues, scheduling issues.

(A discussion was held off the record.)

Madam Chair, that's fine with my witnesses in terms of their scheduling.

CHAIRMAN BAILEY: Okay. Then we will close it up for the night and reconvene and continue at 10:30 tomorrow morning.

REPORTER'S CERTIFICATE

I, JACQUELINE R. LUJAN, New Mexico CCR #91, DO HEREBY CERTIFY that on December 8, 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 21st day of December, 2011.

Jacqueline R. Lujan

Jacqueline R. Lujan, CCR #91
Expires: 12/31/2011