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

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

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

DELIBERATIONS ON APPLICATION OF THE NEW MEXICO OIL CONSERVATION DIVISION FOR THE AMENDMENTS OF 19.15.14.8 AND 19.15.16 NMAC Case No. 14744

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COMMISSIONER HEARING

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

December 9, 2011
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission, JAMI BAILEY, Chairman, on Friday, December 9, 2011, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

REPORTED BY: Jacqueline R. Lujan, CCR #91
Paul Baca Professional Court Reporters
500 Fourth Street, N.W., Suite 105

A P P E A R A N C E S

FOR THE OIL CONSERVATION COMMISSION:

Cheryl Bada, Esq.
Assistant General Counsel
1220 S. St. Francis Drive
Santa Fe, New Mexico 87504

FOR AGAVE ENERGY COMPANY:

Hinkle, Hensley, Shanor & Martin, LLP
Gary W. Larson
P.O. Box 2068
Santa Fe, New Mexico 87504

FOR KAISER-FRANCIS OIL COMPANY:

James Bruce, Esq.
P.O. Box 1056
Santa Fe, New Mexico 87504

ALSO PRESENT:

Florene Davidson

CHAIRMAN BAILEY: Good morning this is the continuation of Case 14720. Today is Friday, December the 9th. All three Commissioners are here, and so there is a quorum.

And I believe we need to pick up with the cross-examination.

MR. BRUCE: Madam Chair, there was one question I forgot to ask Mr. Wakefield, and I'd ask permission to do so.

CHAIRMAN BAILEY: All right. You may finish your direct examination.

MR. BRUCE: I'm handing you something. It's what Mr. Wakefield will be stating, but again, it's a demonstrative exhibit.

JAMES WAKEFIELD

CONTINUED DIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Wakefield, I forgot to ask you yesterday. You have looked at the C-108 also for this project?

A. Yes, I have.

Q. There were questions regarding the wells in the area of review. Have you reviewed the data on those wells?

A. Yes.

Q. Could you discuss your opinion of the data on the wells in the area of review?

A. The C-108 has a several appendices, one of which is Appendix B. Appendix B has a plat similar to the one that I passed out, which has a one-mile -- actually it's a two-mile radius drawn on it. Within that two miles, there's a number of wells that exist, and that's Figure B1.

Figure B2 of the appendix has a one-mile circle showing the wells that exist within one mile of the acid injection gas well.

And then starting on -- two pages after that, it's not numbered, there's a wellbore diagram for the JL Holland, et al., Number 1 Well located 1,980 feet from the north line and 660 from the east line of Section 14, 24 South, 33 East. This was a Bell Canyon test drilled to a depth of 5,425 feet, which does not penetrate the Cherry Canyon.

They didn't find any productive sands. It was a pure dry hole. They set no casing to TD. The only casing in the well is an 8 5/8 casing set at 365 feet. They filled the hole with heavy mud, and there's unknown -- well, I guess there's a 15-sack cement plug at 5,375 to 5,425, and 20 sacks at 5,175 to 5,240, and a 20-sack plug at 1,375 to 1,425 feet. And then across the shoe of the 8 5/8, there's a 20-sack plug at 340 to 390 feet, and there's a five-sack plug at the surface. This was in March of 1961.

The next well that's in the C-108 in Appendix B is the Simms Number 1, which is drilled 140 feet to the west of the Holland, et al., Number 1, or essentially a twin well that's drilled 1,980 feet from the north line and 800 feet from the east line of Section 13, 24 South, 33 East.

And that well was a Morrow test that produced and then was plugged in 1989. When the well was drilled -- and I'll refer to the handout. It's the second well down in the listing of wells, the Simms 1-13. They set 9 5/8 in a 12 1/4 inch hole at 12,479 feet, and they cemented the casing with 850 sacks of cement.

In the diagram for the wellbore in the C-108, they don't show any top of cement. They show it as being at the surface, as if they cemented it all the way to the surface. There's no record of a DV tool on the report that they filed, and there's no indication of any subsequent cementing behind the 9 5/8.

And Kaiser-Francis, we looked at a number of these kinds of wells, and we looked at our own wells, as far as that matter, toward the top of the cement would be by calculations method. And we looked at two different cases, and that's toward the top of handout.

The first thing we did, we took a look at a hole enlargement of 25 percent over whatever the bit size was. Whatever the volume calculates, we'll add 25 percent to make sure we put enough cement in to get the top of cement where we want.

We usually assume one of two things when we don't know anything else: That the cement was either all high strength, which has a 1.15 cubic foot per sack yield, or a tail-in with high-strength cement. And the rest of it ahead of that is low strength, high-yield cement, which is 1.88 cubic feet per sack.

Going through those calculations, you find that on the Simms 1-13, if you use 100 sacks of high strength, you need 1,250 sacks of low strength, high-yield, or 1,357 sacks total to get to 16,000 feet, whereas the 850 sacks that they used yields a minimum top of cement of 9,979 feet or a maximum top of cement of 8,584 feet. Obviously, this meant they didn't cover the Cherry Canyon Zone with cement.

So in our opinion, the Simms 1-13 well does not have cement behind pipe at the Cherry Canyon Zone versus what is shown on the C-108.

They did set, in the P&A of that well, a 45-sack plug in December 2007 from 8,904 to 9,034 feet, and they did set a cement plug across the shoe of the 13 3/8 casing at 5,343 feet with a cement plug of 90 sacks, being 5,101 to 5,392.

Obviously, with the Simms Number 1 having no cement behind the pipe in the Cherry Canyon Zone and being only 1,700 feet -- around 1,750 feet from the acid gas injection well, there's a high risk that the acid gas injection, once it reaches this wellbore, will travel behind the casing, into the zones, all the way up to the Bell Canyon and risk communicating to the JL Holland Number 1 Well which was drilled to 5,425 feet below the shoe of the intermediate casing on the Simms Number 1.

So it is not an unreasonable to assume that by injecting the acid gas injection well, that you would be able to communicate uphole from the Cherry Canyon at the Simms Number 1 Well and communicate to the JL Holland, et al., Number 1, and then have acid gas injection potentially to the surface at the JL Holland Number 1.

Q. Did you use similar calculations on the other wells?

A. Yes. The three wells, like I testified yesterday, that I'm most concerned with are those wells to the north and east of the acid gas injection well.

The next closest well to the acid gas injection well will be the Government L Com Number 2, which is the next page in the figures, Exhibit B. And similar to the Simms Number 1, I laid out there the number of sacks required. It was at drilled and had 7 5/8 casing set. It's got a 9 7/8 hole.

At 12,800 feet, the minimum top of cement would be 10,100. The maximum top of cement would be 8,662 feet. Due to the 630 sacks of cement they put in the hole, they'd need 954 sacks to get the cement to 6,000 feet. Obviously on this well, we do not believe it's covered with cement, even though they showed it that way on their C-108 application.

The next well in the list of exhibits is the Government L Com Number 1. And this is both the L Com 2 and the L Com 1 in Section 18. The Simms was in Section 13.

The Government L Com 1-18, they set 10 3/4 inch casing in a 12 1/4 hole at 13,000 feet with 500 sacks of cement. They said on the report filed with the State of New Mexico that the calculated top of cement by the operator was 9,900 feet. That equates to using high-strength cement with a 1.15 cubic feet per sack yield for the 500 sacks. So we wouldn't dispute that that's the top of cement.

We said there could be a range of top of cement as high as 9,315 feet. Since they didn't do a temperature survey and it's just calculated, it could be higher. It still won't be high enough to cover the Cherry Canyon. In fact, I calculate that Cherry Canyon would require 933 sacks to be covered.

In the two wells to the south, the Smith Federal 1-19 and the Madera Ridge 1-24, the Madera Ridge 1-24 is an example of the kind of cementing volume you need to get coverage across the Cherry Canyon. They put 3,100 sacks of cement in that well, and they only got the top of cement to be 4,150 feet, which is up inside the intermediate casing, which is 13 3/8 set at 5,202 feet. Now, it was actually 13 3/8 casing set at 5,112 feet in Madera 1-24.

There was a question yesterday on the Smith Federal Number 1 about whether or not the cement squeezes that were conducted were adequate to cover the Cherry Canyon. In our opinion, that's not true. They probably were not.

The highest squeeze, indicating that they did not get coverage from the initial cement job of 560 sacks of the 13 1/4 casing -- pardon me, 9 5/8 casing set at 12,400 feet, we calculate top of cement at no more than 9,900 feet.

But the last squeeze that they conducted in the P&A was at 6,900 feet with 100 sacks that has a yield that should generate 367 feet of lift, which puts you at 6,535 feet below the Cherry Canyon Zone marked on their figure, the base of which is 6,515 feet.

So in all, there's only one well out of the group that they've shown inside their one-mile radius that will have cement across the Cherry Canyon Zone of injection, which is another reason why Kaiser-Francis wants the well not to be approved, because we feel that there will be communication to other zones through the life of the acid gas injection.

Q. Now, I understand that Kaiser-Francis doesn't want the well approved. If the Commission does approve the well, would you like conditions of approval?

A. Yes, we would.

Q. Could you specify some of those for the Commission?

A. We feel that Agave should furnish -- and Yates, whoever is going to drill the acid gas injection well -- should furnish the offset operators daily reports during the drilling and completion of the well, copies of the logs, the cores, any drill stem tests.

And further, I think they're already set up by virtue of some regulations to file with the State or the federal government reports on the volumes and the pressures, and we would want copies of that each month.

And then if there's any subsequent workover, we'd want to have copies of those.

Q. Do you think there should be an annual shut-in buildup pressure test?

A. Yeah. I think it would -- I think it's already been said that there would have to be MIT tests. In conjunction with that, we think there ought to be a calculation of the bottomhole pressure from the surface measurements.

Q. And should the five wells that you just identified be re-entered, be properly plugged and abandoned?

A. I think that would be imperative.

MR. BRUCE: Thank you. That's all the questions I have, Madam Chair.

CHAIRMAN BAILEY: Do you have cross-examination?

MR. LARSON: I do. I have a preliminary matter.

Yesterday the Commission took administrative notice of the filing of the application. I wanted to make you aware that I brought extra copies with me this morning, if you'd like me to distribute them for your reference.

MR. BRUCE: I have no objection.

CHAIRMAN BAILEY: Yes. We would like to have them, please.

CROSS-EXAMINATION

BY MR. LARSON:

Q. You mentioned yesterday during your testimony that injection by Agave would put a cloud on South Bell Lake Unit property. What did you mean by the term, "cloud"?

A. I think anyone who examines the South Bell Lake Unit and future potential, or if we were to drill wells around the south edge, would also see the threat of acid gas injection as being a problem in the future.

Q. When you say, "cloud," does that mean cloud to the title document?

A. Cloud in terms of a risk that needs to be associated with the purchase price. There's a reduction in value. I misspoke as far as title. It was just a generalized expression.

Q. Thank you for clarifying that.

Is it possible that a potential buyer would view the proximity of the gas plant and the ability to send sour gas to the plant without having to treat it at the wellhead as a positive, as a benefit, in terms of purchasing the property?

A. I suppose.

Q. Has Kaiser-Francis Anadarko ever developed an acid gas injection well?
A. No, we have not.
Q. Have you personally been involved in the development of an AGI well?
A. No, I have not.
Q. And does Kaiser-Francis Anadarko have an in-house geologist?
A. I'm basically the in-house geologist.
Q. Did you consult with a third-party geologist with AGI experience regarding Agave's application?
A. Restate the last part. I'm not quite sure what you --
Q. Did you consult with a third-party geologist with experience in AGI wells regarding the application?
A. No.
Q. Do you have any basis to dispute Mr. Gutierrez's use of the methodology for determining the impact of the injection zone that is generally applied by professional geologists?
A. I think it's a generalization that Mr. Gutierrez was referring to. We, all over the United States, typically draw circles around wells to express either recovery to date or injection volumes to date or in the future. It doesn't make them right.

We've been -- I have been involved in a number of projects, waterflooding and, in some cases, some gas flooding, and obviously things are not either circular or elliptical. They typically, in sandstone, are more linear. And typically, you found things happening from the injection at producing wells or response wells that were unanticipated because of the differences in reservoir quality, and seldom was it ever circular.

Q. In evaluating Agave Energy's application, did you review any current studies addressing the impact of acid gas injection on saline water?

A. I read a few articles. And basically it mirrored what Mr. Gutierrez said, that it stays as a plume, and the mixing front happens at just that, the mixing front. It doesn't become dispersed, like you would with carbonated water in a bottle. It becomes a front. And what he's correctly stated is that you don't move all the water. You just move the movable water.

Q. Do you recall the names of those studies?

A. One was in Craft and Hawkins, and there was one put out about the Yates waterflood or Yates gas injection. I think there's also some about the Snyder gas injection.

Q. Was that a Geolex paper you read?

A. No. I don't think I'd ever even heard of

Geolex until Mr. Gutierrez mailed this application.
Q. And did you review any current studies addressing the effect of acid gas on producing wells?
A. I know it is extremely corrosive. I've read a little bit about that. We do have a corrosion engineer in house who confirmed that.
Q. So you conferred with your corrosion engineer. Does your corrosion engineer have any experience with acid gas wells?
A. No. We just have -- and I've done a lot of corrosion work, too, as a production engineer. I worked as a production engineer for many years, for the first 10, 12 years of my career, and we dealt with corrosion from carbon dioxide all the time.
In Oklahoma we have a little bit of carbon dioxide in nearly all the formations, and we are experiencing severe casing and tubing erosion in all of those wells. We're having to either plug them or repair them.
Q. I believe you testified yesterday that you made calculations regarding the mobility of the plume. Could you share those calculations with us?
A. I'm not sure what that was about. Mobility? Define what you're saying.
Q. The migration of the plume.

A. In terms of what?

Q. Well, I'm just referring to the calculations you made.

A. I'm trying to remember what specific statement I made that you're referring to.

Q. Without reviewing the transcript, I couldn't tell you the specific statement.

A. I can't refer to it without you doing that.

Q. Fair enough.

Would it be fair to say that your testimony regarding the displacement of the saline water in the injection zone and the migration of the plume is based on your experience with produced water injection?

A. Some. And it's also based upon the fact that I've looked at and read some of the literature. At Skelly Oil Company, we conducted the Vess Unit, which was a gas injection project. And we injected gas in the top of the formation, and then we injected water at the base to squeeze the oil zone.

And we did some of the same things -- I looked at some projects in the Michigan Basin. The same type of situation, where you had vertical segregation. You inject gas into the top of the zone and you inject water into the base to squeeze the oil column. And you're working on the difference in residual oil saturation to gas and water to accomplish your end.

Q. Were those tertiary recovery projects?

A. They were in conjunction with each other.

Q. And was there a component of H2S in the gas that was injected?

A. Not that I remember.

Q. And does Kaiser-Francis Anadarko produce any sour gas in Southeast New Mexico?

A. Yes, we do.

Q. And do you treat the H2S at the wellhead?

A. We did a couple of times, and we found -- Conoco operated one we have an interest in, and we took over operations. In the meantime, Conoco changed the gas purchaser from a sweet purchaser to a sour and dismantled the aiming unit. But we've had our own aiming units on a couple of wells and produced them to economic limit.

Q. What was your experience with the operational quality of the aiming units?

A. We didn't have much trouble.

Q. Did it increase the cost of the --

A. Of course. You had to buy a machine.

Q. And then there were ongoing operating costs, as well?

A. Sure.

Q. And what processing plants does Kaiser-Francis

Anadarko use for processing its sour gas?

A. Our gas market handles that. I don't necessarily have the names of all the people we sell gas to. In the Bell Lake Unit we sell gas to DCP from the low pressure side. On the Devonian gas well, which is sour, it has changed hands. And it used to be -- you know, I just don't remember the name. But there is a line that we use for that.

Q. And are you aware that there's several DCP processing plants in Southeast New Mexico that use acid gas injection?

A. I have no idea.

MR. BRUCE: I'll pass the witness.

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

COMMISSIONER DAWSON: I have no questions.

CHAIRMAN BAILEY: Commissioner Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. Mr. Wakefield --

A. Could you speak up a little bit? I'm very hard of hearing.

Q. I'm a very soft speaker, so we have a bad combination.

A. I know.

Q. You infer that CO_2 would not stay in the injection layers, that it would migrate all the way to the top-most layer through the intervening Caprock?

A. That's not exactly what I said. I'm not sure which time you're talking about.

Initially I had conversations, I believe, with Mr. Gutierrez. And we were talking about the 177 feet of pay and the weakness of the interval capping of each individual sand unit, that it would tend to trend all the way to the top and track along the top of the zone.

But I changed my mind and agreed with Mr. Gutierrez that there's actually enough barrier at the top of each sand interval he's going to perforate that I think now what will happen is that you'll have that segregation in each sand. It will not all go up to the top. It will go to the top part of each individual sand.

So like the bottom of the top few feet would have it, the next sand, the top few feet. So they would go all the way through the reservoir that way, unless there's a break in the caps for each individual sand. But it's fairly continuous. But it's less likely that it will all go to one zone. It's more likely that it will stay within those zones.

Q. Within a zone, if the CO_2 is migrating to the top part of the zone, wouldn't that affect the injection pressure?

A. I don't think it will affect injection pressure just because of that. The injection pressure is going to increase with time due to the fact that you're increasing the amount of volume you're putting into a reservoir at virgin pressure. You're going to see an increase in time because it's going to be a back pressure effect.

You have to force another molecule down the line or into the formation for each one you push in. So as time goes on, you're extending it further and further away, and that pressure gets reflected back to the wellbore. That's absent any additional issues from scaling or plugging of the formation or face or anything like that.

Q. So you would perhaps infer instead that the acid plume migrates away from the wellbore, the CO_2 well taper towards the top of the individual layers?

A. Yes, right.

Q. I think that that would limit the amount of reservoir that the injectate is seeing, and that would rapidly increase pressure.

A. It could. I'm not saying it won't. I just haven't made those calculations. There's a way to do that. I thought there was more overriding problems than that.

We talked about it being a virgin pressure. With the difference -- when you're injecting water -- I tried to say this yesterday. When you're injecting water, there's enough column or pressure from the water that you don't need much pressure absent, you know, friction effects or scale effects or formation damage, to get water into the formation initially.

But with carbon dioxide, if you have 2,600 pounds of bottomhole pressure, you're still going to have 5- or 600 pounds of surface pressure before you start pumping the first mcf in the ground or the first barrel in the ground just because of the difference in columnar weight.

Q. A lot of the new deep development is horizontal?

A. It's nearly all horizontal. There's virtually no vertical wells being drilled.

Q. And if you have a plume that has a maximum diameter of a mile, going with the idea that it is a plume, I don't think that any of that development might be restricted, since you could enter and drill underneath the Cherry Canyon?

A. It's possible. But the problem with all of that drilling is you need to have your sump or your pilot hole on the downdip side. And the downdip side of your lateral for us at Kaiser-Francis is going to be along our south boundary, drilling north, to take advantage of dip because dip will make a difference.

It will drain -- in a horizontal wellbore, we're going to drain from the highest point to the lowest. So we want the sump to be along the south boundary.

Q. You spoke of extra costs associated with drilling through a formation that would have an acid gas in it, H2S. Could you give a very broad estimate of what it would be per well going through a formation as thick as the Cherry Canyon in this area?

A. I wish I checked on the cost. It's probably two to three times the cost of conventional casing.

Q. But you're only viewing that special casing in a --

A. 500 feet or so. I think he set up 330 or 40 feet of zone. We'd want to be below that and above it.

Q. You're talking a difference between steel casing and stainless casing of 500 feet?

A. 500 feet. It shouldn't be a huge expense.

Q. Anything that changes in the surface when you're drilling?

A. You'd have to prepare for and have heavier mud in the hole, in case you encountered it. You wouldn't do that today. It would be down the road. The casing would be immediately.

Q. On the volumetrics of CO2 injection compared to injecting water, I presume you're aware that liquid CO2 is compressible, where water is not?

A. True.

Q. I was noting that liquid CO2, supercritical CO2, is compressible, whereas water is not. And more liquid CO2 could be put into a reservoir than water if you're injecting water at the same rate.

A. You're stating that as time goes on?

Q. Right.

A. That the increase in reservoir pressure won't necessarily increase the volume of -- to be -- you're suggesting, and I don't disagree, that the 5.615 conversion factor for a barrel would change with pressure?

Q. Time and pressure, and also specific gravity would change.

A. Specific gravity will change. They estimated .84 specific gravity in the reservoir at the operating pressure and temperature.

Q. If the acid density of the CO2 increased over time, what would the impact on the specific gravity be, in your opinion?

A. If it increased, it would not have -- if it increased to 1, it would not have any gravity effects.

Q. So it would lose some of the buoyancy over time?

A. If that was true, yes.

Q. All of these models that people use for these injections do not incorporate geochemistry. Are you aware of geochemical tracking mechanisms that would impact the size of the plume?

A. You mean the dissolution of carbon dioxide?

Q. Dissolution, residual trapping, mineralization.

A. Mineralization, as long as your pH stays below 5, I don't think you have much of that.

Q. Mineralization takes a long time, 1,000 years, 2,000 years, to be significant?

A. Yeah. And we're talking about a fairly acidic environment which minimizes the formation of scales by the combination of water and the CO2. What it will do is dissolve calcium carbonate or limestone or dolomite formations.

Q. My understanding, and this was brought up in a few of the direct questions on some cross-examination, was that you believe perhaps that the CO2 plume will stay as a pure CO2 plume at the front as it moves away from the injection wellbore.

But I do believe that geochemically, you will have dissolution of CO2 and you will have residual trapping of CO2 as that CO2 passes through the water on the way to the front. So at the front, wouldn't you have a more diffuse CO2 than you would have at the beginning of injection?

A. What you have at the leading edge is a mixing, which matches what you're saying, I think. And as time goes on, you move that mixing front forward. And behind it, you'll have a plume. But at the front, you're going to have a mixture. It isn't a very large front. It tends to be a fairly sharp front.

And that's why, with CO2 injection and oil, that you do CO2 injection and then water injection in order to sweep out the CO2 that's not contacting and bringing in a new group of CO2 or a new batch of CO2 or a plume that then will be able to contact. You alternate back and forth to create more mixture and diffusion.

Q. I find generally the comparison of CO2 for EOR purposes is not a good comparison for CO2 into aquifers primarily because miscibility of wells adds up --

A. That's why they aren't doing that. I'm not suggesting they do that here. It's not important.

Q. The chemistry in the interactions of the CO_2 and the water change significantly in the absence of hydrocarbons. The general effect is you have higher dissolution and greater residual trapping of the CO_2. That's why they're --

A. So you're going to leave more behind?

Q. You're going to leave more behind as you go through.

A. So your affected area becomes more carbonated in terms of water being carbonated, like a soda pop, and behind the front, is you what you're saying?

Q. Right. So what do you think the impact on that over a generic, purely volumetric CO_2 point would be?

A. I'd put it halfway between my case and their case.

Q. So a smaller plume?

A. Yes.

COMMISSIONER BALCH: Those are all my questions. Thank you.

CHAIRMAN BAILEY: I have no questions.

Do you have any redirect?

MR. BRUCE: No, I do not,

CHAIRMAN BAILEY: Then are you through with your presentation?

MR. BRUCE: I am through.

CHAIRMAN BAILEY: Then it's time for closing statements?

MR. LARSON: Madam Chair, I have some brief focus rebuttal testimony.

CHAIRMAN BAILEY: All right.

MR. LARSON: I'd first like to call Mr. Villa.

IVAN VILLA

REBUTTAL EXAMINATION

BY MR. LARSON:

Q. Good morning, Mr. Villa. You realize you're still under oath?

A. Yes, sir. Good morning.

Q. In today's environment, is injection of CO2 and H2S removed while processing sour gas generally accepted as the best available practice?

A. Yes, it is.

Q. And in designing the Red Hills Plant, did Agave Energy consider any alternatives to injecting the acid gas?

A. Yes.

Q. And what were those alternatives?

A. Alternatives to the acid gas injection were a couple. We looked at the chemical scavenger at the wellhead, and we also took a look at the sulfur recovery unit at the plant.

Q. What's involved in chemical scavenging at the wellhead?

A. Chemical scavenging in this case would require vessels. We also -- in order to basically protect our system, we would look at installing slam valves at the meter and also monitoring equipment to assure that we did not receive H_2S into the gathering system.

Q. And what would be involved in installing a SUR? I assume you mean sulfur recovery unit?

A. Yes, sir.

Q. What would be involved in installing a SUR unit at the plant?

A. The problem with this at this facility is we're hampered by the amount of H_2S in our inlet feed stream to this unit.

If you remember correctly, our TAG is going to consist of about 95 percent CO_2, 5 percent H_2S. Typically, to achieve the 98 percent sulfur recovery that we would require for the permit, we would need somewhere in the vicinity of 15 to 25 percent H_2S in the incoming stream to the sulfur unit.

In order to get over -- or in order to solve that issue, what you would have to do is add more catalytic stages to the design. We felt that was going to drive the capital costs up and also significantly increase our annual operating costs for the facility. Also, we really felt that was going to hamper our operational reliability for the plant itself.

Q. So if the SUR unit goes down, you have to shut down the entire plant?

A. We would be allowed to flare for a certain period of time. But if there was any major malfunctions, yes, the field would go down.

Q. So the operators couldn't transport gas to the plant?

A. That's correct.

Q. And the permit you just mentioned, is that an air permit?

A. That is, yes, sir.

Q. And Ms. Knowlton will address that?

A. Yes, sir.

Q. What issues do operators confront when they treat H2S at the wellhead?

A. Well, in this case, you know, we were talking about chemical scavenger. This process is extremely sensitive to pressure swings in the system. As I mentioned before, we would require a slam valve on location.

So typically, the wells that we are used to dealing with in this area are mainly oil producers. So what happens is when our slam valve goes shut, the producer typically likes to keep producing the well. So there's a strong possibility that there should be a significant amount of flaring at the wellsite.

Q. There would be flaring at the actual wellsite?

A. Correct.

Q. Would that come under Agave's air permit, or would the operator have to have an air permit?

A. That would be something the operator would have to deal with.

MR. LARSON: Pass the witness.

REBUTTAL CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Villa, would you confirm what you said yesterday, which was that you did not do any economics for treating the H2S at the plant in combination with flaring?

A. That's correct. We didn't really have any detailed information, but we knew as a -- I guess a ratio of what it would cost us to operate an acid gas injection system. We felt comfortable in providing that information.

Q. And of course, treating it at the plant, that's factored into the costs you would pay a producer?

A. That's correct.

MR. BRUCE: Thank you.

CHAIRMAN BAILEY: Commissioner Dawson?

EXAMINATION

BY COMMISSIONER DAWSON:

Q. Do you roughly know how much SUR units cost?

A. You know, I'd feel uncomfortable throwing a number out there. We've got some past information with SUR units that have been installed in the past. I could probably say that we were somewhere in the neighborhood of four times the cost of operating an acid gas injection well.

Q. When an operator signs a contract with Agave to remove the acid gas from their well or from their gas stream, do you -- you guys charge them on the basis of -- is it -- how do you charge them? Is it a thousand cubic feet or --

A. Usually what happens is the producer would see a treating fee, a cost per mcf, to remove H2S and the CO2, in this case, from the gas, from their gas.

Q. What does that usually cost an operator?

A. It just varies by the technology you use.

Q. The percentages?

A. Yeah. Usually that fee is -- I would be guessing. But we're probably in the realm of 7 to 12 cents per mcf for treatment.

COMMISSIONER DAWSON: No further questions. Thanks.

EXAMINATION

BY COMMISSIONER BALCH:

Q. I have just one question, and you may want to defer it. Questions were brought up about the cement status in the nearby wells, and this document was prepared by Geolex. But are you familiar with those wells? Did you look at those yourselves?

A. Yes, sir.

Q. Would you care to address the cement issues that were brought up?

A. I'd feel extremely uncomfortable addressing the cement issues.

COMMISSIONER BALCH: All right.

CHAIRMAN BAILEY: I have nothing. So do you have any redirect?

MR. LARSON: I have nothing further for Mr. Villa.

CHAIRMAN BAILEY: Then you may be excused.

MR. LARSON: I next call Ms. Knowlton.

JENNIFER KNOWLTON

REBUTTAL EXAMINATION

BY MR. LARSON:

Q. Good morning, Ms. Knowlton. As I told Mr. Villa, you recognize you're still under oath?

A. Yes.

Q. Mr. Wakefield referred several times to Yates Petroleum. This is not a Yates Petroleum project, is it?

A. No, sir. This is an Agave Energy project. Agave is a wholly-owned subsidiary of Yates Petroleum. But the Red Hills Gas Plant and the proposed Red Hills acid gas injection well would be an Agave only project.

Q. And Agave is a stand-alone corporation?

A. Agave is a stand-alone subsidiary of Yates.

Q. Mr. Villa addressed alternatives to injection for disposing of H2S and CO2. If Agave were to install a sulfur recovery unit at the Red Hills Plant, would that then involve the flaring of sulfur?

A. Most of the time, we would hope that the TAG stream would be treated by the SUR. But SURs are notorious for operational issues dealing with variability and concentration and pressure, so we would probably be flaring more with a SUR than we would be with an acid gas injection well.

Q. And would that involve additional permitting requirements by the Air Quality Bureau?

A. Significant, actually. There's an SPS, a new Source Performance Standard. This is an EPA rule, Subpart LLL, which is the standards of performance for onshore natural gas processing SO2 emissions. It is currently under review, and there were promulgations and changes to this rule on August 23rd, 2011.

This rule would require a 98 percent reduction in SO2 emissions at an onshore natural gas processing facility. A SUR would have difficulty meeting that 98 percent reduction efficiency.

In addition, the natural ambient air quality standard for SO2 on the short-term, a one-hour standard, a new standard was promulgated this summer which significantly lowered it which would also inhibit our ability to flare, which we would have problems doing with a SUR.

Q. If you did obtain an additional air permit for the sulfur flaring, what happens when you exceed the permit limitations?

A. We would have dire consequences with the Air Quality Bureau by doing so.

Q. Would it involve shutting down the plant?

A. Potentially, it would involve shutting down the plant while we fixed the problem. The Air Quality

Bureau has done that with other natural gas processing plants with SURs in the past.

Q. You would be required to report those exceedances?

A. Yes. We would be required to report those exceedances to the Air Quality Bureau and probably to the EPA. Because given the size of our facility and the potential for emissions, we would also have EPA permits.

MR. LARSON: That's all I have.

CHAIRMAN BAILEY: Any cross-examination?

MR. BRUCE: No questions.

CHAIRMAN BAILEY: Commissioner Dawson?

EXAMINATION

BY COMMISSIONER DAWSON:

Q. On the other acid gas injection wells that Agave operates, have you ever had to shut down due to air quality?

A. No, sir. We actually installed that acid gas injection well due to a compliance order, where we were just simply flaring our gas, and the Air Quality Bureau had issues with how we operated our facility. So in settlement of that compliance order, we installed our acid gas injection system.

And since then, we have had no air quality -- actual air quality violations. We've had some paperwork issues, but no actual air emission violations.

Q. Roughly how many acid gas injection wells did you say you guys operate?

A. We have just the one, the Metropolis at the Dagger Draw Gas Plant.

COMMISSIONER DAWSON: No further questions.

CHAIRMAN BAILEY: Commissioner Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. Barring CO2 emission regulations, is there anything to stop you from injecting less CO2 or H2S?

A. Once you have the two combined in a TAG stream, the separation of the two is difficult and expensive. I'm not 100 percent certain how you would do that. I know there's membrane technology that you could use to separate the two, but I do not know for sure what that would entail and what those costs would entail.

COMMISSIONER BALCH: Thank you.

CHAIRMAN BAILEY: I have no questions. Redirect?

MR. LARSON: Nothing, Madam Chair.

CHAIRMAN BAILEY: You may be excused

MR. LARSON: Next I call Mr. Gutierrez.

ALBERTO GUTIERREZ

REBUTTAL EXAMINATION

BY MR. LARSON:

Q. Good morning, Mr. Gutierrez.

A. Good morning.

Q. You also remain under oath.

A. Yes, sir.

Q. Mr. Wakefield referred this morning to the offset well diagrams in the application.

A. Yes, sir.

Q. Where did you receive the information that's included in those diagrams?

A. These diagrams were developed based on the information that is included in the OCD files as an aggregate of all of the plugging reports for each of those wells. Since a number of these wells have had multiple events, it was quite a synthesis job to do that. And so that's how we derived that information.

Q. Mr. Wakefield also addressed the issue of horizontal wells. In the offset wells that you looked at, where is the location of the vertical hole?

A. Well, I mean Mr. Wakefield mentioned that the vertical hole is typically on the downdip side of the horizontal wellbore. However, when you look at even the map that he had yesterday, which actually is a larger scale, so it's easier to see, in fact, the majority of these have the vertical hole on the updip side, rather than the downdip side, with the exception of one Yates well in Section 25. And then there are some that just have it on strike. So really, it's all over the map.

Q. Agave has not received any feedback from Yates regarding the well you just identified?

A. No, or from EOG. EOG has quite a few. I mean the bulk of the leases in this area south of the Bell Lake Unit are held by EOG and Yates, and they're actively drilling this play. And they were both notified of the proposal and didn't have any concerns.

Q. When you and Geolex were retained by Agave to prepare the application, did you assume that Agave would not want to put any of the offsite wells in the area in danger of corrosion from acid gas?

A. Absolutely. The last thing Agave wants is to have this acid gas get out of the injection zone and wind up in someone else's production well or, God forbid, get to the surface, which I think is a virtual impossibility.

Q. Do you have your PowerPoint up?

A. I can, or we could just refer to the hard copy.

Q. That's fine. I'm going to refer you to page 23 of what was marked as Exhibit Number 3. I'll refer to that in just a moment.

What do the recent geologic studies show regarding the buoyancy effect of acid gas in a saline reservoir?

A. You know, I brought a whole stack of papers that I spent some time reviewing last night that are kind of the regular papers that we work with in this AGI business. And really quite a bit of the recent research, including some of the major studies done by Qanbari and Bachu in 2011, indicate that in fact the buoyancy affect is relatively small in the injection of these CO2 plumes and that in fact the migration is largely controlled by the relationship of the mobility ratio between the injected gas and the formation water. And that's especially true in a discrete layered reservoir similar to what we're doing here in the Cherry Canyon.

I think it's very important to note that the reason why we selected a number of these different zones is not because we need all of these zones to put the gas away, but in effect because we're trying to distribute the gas over a significant portion of that Cherry Canyon while staying away from the production above and below, but to break it up and enhance the ability of that gas plume to be relatively smaller in overall extent and to reduce this whole buoyancy effect.

Q. Looking at your Exhibit Number 23 there, what would be the dispersion within those sands there?

A. I think that while there may be some -- what all of the studies show and what our experience has shown is that while there may be some buoyancy effect immediately in the vicinity of the wellbore, as you get farther and farther away from the wellbore and you have other both geochemical and physical factors operating, you tend not to have a "gas cap" sitting at the top. So that you don't have -- that the buoyancy effect is relatively small.

Q. Would the gas be dispersed between the layers indicated on your exhibit there?

A. It would be. And I think one of the other things that really affects the extent that we haven't talked about -- and it's because, you know, a lot of these reactions that take place within a saline reservoir when you inject acid gas are not that easy to quantify and to understand in terms of exactly what impact they have on the overall extent of the plume.

So what we try to do is to use the most conservative kind of model. I mean the model that we use -- for example, if you look at the literature with Qanbari and a number of others that have done a lot of work, you know, the bulk of this acid gas injection has been going on for the longest period of time in Canada, in Alberta. So a lot of the work with saline reservoirs that have been taking acid gas for in excess of, say, 15 to 20 years, is up in Canada. So a lot of the work is done up there.

And what they found is that frankly, you reduce the ultimate extent of the gas plume by as much as 10 to 20 percent due to, for example, the formation of hydrates and the geochemical complexing of that CO2 within the saline aquifer.

We don't take any of that into account, because what we're trying to do is do the most conservative look at what that potential extent would be. Because our client is more concerned than anybody else about the potential for keeping that acid gas in the reservoir.

Q. And what do the recent studies show with regard to the formation of hydrates within saline reservoirs?

A. Well, the studies like the one that I just referred to show that you can have up to 10 to 15 percent, in some cases up to 20 percent, of that injected fluid that winds up as a permanently complex -- either hydrates or other geochemical reactions in that saline aquifer.

Q. Taking that factor into consideration, would that effectively increase the safety factor that you testified about yesterday?
A. Yes. I think that the way we looked at it was a very conservative way.
Q. So in what you discussed yesterday, you hadn't taken this phenomenon of hydrate formation into account in generating your safety factor?
A. That's correct.
Q. How many barrels of CO_2 and H_2S would Agave have to inject in order for the plume to reach the southern boundary of the South Bell Lake Unit?
A. Approximately 110 million barrels.
Q. And what's going to be the actual injection over a 30-year period?
A. About 37 million barrels.
Q. In light of those numbers, are we still at your 200 percent safety factor?
A. Yeah. It doesn't matter whether you calculate it in barrels. I know the numbers may sound large. But it doesn't matter if you calculate it in barrels or cubic feet or anything else. Volume is volume.
Q. I'll refer you now to page 25 of Agave Exhibit 3. Do you agree with Mr. Wakefield that the difference in elevation between the top of the Cherry Canyon at the

southern boundary of this unit and the location of the well is 400 feet?

A. No. If you look at our map, the contour interval on this structure contour map is 25 feet. If you look where our well is and the edge of the South Bell Lake Unit, the difference in elevation is about 65 feet, so it is quite flat.

Q. And again referring to the recent geologic studies, what do those studies reveal in terms of corrosive effect of acid gas on producing wells?

A. It's interesting, because API has done some work recently. And what is shown -- and actually, also there's been quite a bit of work done in the EOR community. Because if you think about it, EOR is a tertiary recovery mechanism, so it ends up getting used in fields that have a lot of old wells. So that is a clear concern.

But what some of this work that API and others have done indicates that if you have a cement sheath around the casing, that you end up having geochemical reactions that take place with the outside of the cement that is in contact with the CO_2 and formation water, and that those reactions tend to pretty well seal off that cement. And that's not with particularly corrosive-resistant cement, just with normal cement. And that you don't get a significant penetration of that cement sheath into the casing.

Q. Mr. Wakefield indicated this morning that he believes that Agave will see an increase in pressure over time with its injection. How does that comport with your experience with acid gas injection wells?

A. Well, I think -- in fact, what we have seen ourselves with the eight wells that we have done and what the literature has indicated is that actually the injection pressures tends to go down over time as you inject into these reservoirs, rather than up.

Because while -- clearly the higher the rate that you inject at, you're going to have higher pressures. But for keeping injection at a constant rate, what we have seen is that actually over time, the reservoir becomes better at accepting that acid gas and in fact lowers -- the pressure decreases.

In a very similar environment in the Entrada Sandstone at the Anadarko acid gas injection well in the San Juan Basin, we've seen a pretty dramatic drop in just the first six months or so of operation.

At Southern Union, we have seen the same thing. At Lineham we've seen the same thing. At Artesia, which has a 10-year operating history, we've seen the same thing. So really, we haven't seen that problem of pressuring up the reservoir.

Q. Is there any reason to believe that the data you've seen on these existing wells would be any different from what Agave would expect to see with the Red Hills well?

A. No, sir.

MR. LARSON: I'll pass the witness.

CHAIRMAN BAILEY: Any cross?

MR. BRUCE: I think I just have one question.

REBUTTAL CROSS-EXAMINATION

BY MR. BRUCE:

Q. You talked about the buoyancy decreasing as you move away from the wellbore, I believe?

A. Yes, sir.

Q. How is that determined? Was there drilling of a monitor well or core studies done?

A. It's been done by a variety of different ways. One of them is by looking at 3D seismic shot at periodic times over the injection. So in other words, they'll compare the actual -- you can see the actual CO2 plume over time with a seismic base case and then subsequent seismic. That's one way.

The other way is that there's been quite a bit of modeling done to where there is detailed reservoir information, and it's the results of those models. So in both of those instances.

Q. But no type of monitor wells to monitor where the plume goes and at what date and what shape it forms?

A. No. What people -- the last thing people want to do is penetrate their injection reservoir with a monitor well. So typically, you use remote sensing or modeling techniques.

MR. BRUCE: I have nothing further, Madam Chair.

CHAIRMAN BAILEY: Mr. Dawson?

EXAMINATION

BY COMMISSIONER DAWSON:

Q. If the AGI plant is approved, do you guys intend on doing 3D seismic or modeling? What's your intention on that?

A. Commissioner, what our intent is is first to take a core of both the Caprock and the reservoir and then to have that core analyzed for both permeability to formation fluid, as well as to our injected TAG, and then to go back and feed that back into a model of the reservoir.

Q. Have you currently done any cores or modeling with the Cherry Canyon Reservoir intended injection zone?

A. We have not.

Q. Do you know if anyone else has?
A. No, sir. We have done it, however, with the Entrada, because we have taken core from there at the Anadarko well. And we have done it with the lower Bone Springs at the Lineham well.
Q. On the Entrada or the Lineham wells, are there other wells nearby that could have been impacted from the acid gas injection --
A. Yes, sir.
Q. -- like I mean plugged and abandoned wells or ones that did not have proper cement bond?
A. Absolutely. As a matter of fact, at the Anadarko situation, we not only have wells nearby, but we also have an underground coal mine literally within 100 yards of where the -- no, it's not 100 yards. It's probably more like 300 yards away from where the well has been drilled.
But really, the ones that -- AGI projects that we've done that have the closest wells that are potentially affected, I would say the target of AGI was probably the one that had a well that was very close. I mean we knew that that well would be within the 30-year plume, and we did go back in and re-plug that well.
But it was within -- I mean it was well within our calculated 30-year plume. And it penetrated the top

of the injection zone that we were going to inject into and had an improper plug at the base, so we clearly wanted to redo that.

Q. Did that well have cement behind casing in the injection zone?

A. No, it didn't. What it had, basically, was a -- it was a very old well. And it basically had essentially a cast-iron bridge-plug, some cement thrown in the hole and a bunch of steel wool dropped in the hole, as well.

Q. So you squeezed the casing and cemented it, or did you just put more plugs --

A. No, sir. We removed all of what was in the hole, which was -- because it was all at the base of the hole. And that was our concern, because that's what penetrated the injection zone.

So we removed all of that. We perforated the casing again, and then we squeezed and then we filled the entire bore hole with cement.

Q. Did you review the wells that he was talking about on the casing and find out that some of those wells indeed did not have a good cement bond behind the casing on it?

A. Yes, sir. As I discussed yesterday in response to Commissioner Bailey's question, we did review those, and they are presented in here.

Although while I would agree with Mr. Wakefield regarding the Holland Number 1 Well, which was not a concern to us because the TD on that well was 5,400 feet, which is way above our proposed injection zone, that well does not -- it was just a dry hole, and it was filled with heavy mud. It was not cased at all.

In the Simms Number 1 Well, we took and aggregated all of the information that was provided in the OCD records. And the reason why we stated what we did and the way we drew these is if you go back and look at the records, it does say that the long string in the Simms Number 1 was cemented to the surface. That was not our characterization. That came straight out of the OCD records. Similarly, the Government Com Number 2 showed that.

Now, I mean we can only go based on what we find in those records. But we felt they were reliable because there were extensive records. And that Simms Number 1 was plugged in 2007, so it wasn't that long ago that that well was plugged. And the Government Com Number 2 was plugged in 1990.

Q. What would your feelings be about going in and re-entering those wells and putting additional plugs in those wells if Kaiser-Francis wanted you to do so?

A. I would think that if we would go back and if we could verify that there isn't cement across there based on the plugging records, which is contrary to the information in the OCD records and what we saw, and the well is within that 30-year plume, then I would consider that that might be appropriate.

But I certainly wouldn't consider it appropriate for wells that are outside of that plume, because we've calculated that to be the maximum extent, without taking into account factors which we believe really are operative out there, that would reduce the ultimate size of that plume.

COMMISSIONER DAWSON: No further questions. Thanks.

CHAIRMAN BAILEY: Commissioner Balch?

COMMISSIONER BALCH: Just one.

EXAMINATION

BY COMMISSIONER BALCH:

Q. Your observation that injection pressure over time actually drops in AGI wells I find to be interesting and not in line with modeling that I have done in the past. However, most of those models have assumed you're injecting at the maximum injection pressure that you can sustain.

How does that number compare to typical

injection pressures in an AGI well?

A. You know, they are typically quite a bit lower than the maximum pressure that you can sustain. What we have found and what we believe to be -- we don't fully understand -- to be perfectly honest, we don't fully understand what the mechanism is where we're seeing that, except that we believe that, you know, there may be some dissolution of and opening of additional pore space in the reservoir, almost like a continuing acid job, if you will. And that in many of the reservoirs that we've looked at -- not in the Entrada, because it's sandstone.

But I mean in quite a number of the other reservoirs, they're carbonate or carbonate limey reservoirs. So you know, that may be a slightly different scenario. But generally, we are operating these AGI wells at far below the maximum allowable operating pressures.

Q. And the same can be said for Canada, where you said there's a 15- to 20-year injection history?

A. Yes, sir.

Q. Same observation, lower injection pressure than they expect?

A. That's correct.

COMMISSIONER BALCH: That's all my questions.

CHAIRMAN BAILEY: I have no questions.
Any further --
MR. LARSON: I have nothing further for Mr. Gutierrez.
CHAIRMAN BAILEY: Then you may be excused.
THE WITNESS: Thank you.
CHAIRMAN BAILEY: Do you have any other presentation to make?
MR. LARSON: I have no rebuttal testimony.
MR. BRUCE: No, I don't.
CHAIRMAN BAILEY: Do you have closing statements?
MR. LARSON: I do.
I submit, Madam Chair, Commissioners, that Agave Energy, as the applicant in this case, has sustained its burden of demonstrating that it can safely inject H2S and CO2 into the proposed injection zone.
I think Agave Energy has demonstrated that it is the best available alternative for disposing of acid gas derived from processing sour gas and that it will have economic benefits both to Agave and the operators selling gas to a Agave, as well as environmental benefits.
I certainly understand Mr. Wakefield's concern about his company's current and future investments in the

South Bell Lake Unit. But the geologic evidence indicates that his unit simply will not be negatively impacted by the injection zone, and I request that the Commission approve Agave's application in its entirety.

MR. BRUCE: Commissioners, Agave is a good company. Kaiser-Francis doesn't have any problem with that. But they're concerned because it will be drilling through the injection zone for future wells. And due to non-radial flow, acid gas will preferentially migrate toward the South Bell Lake Unit.

Furthermore, the injected volumes are quite high, approaching 40 million barrels of fluid at a minimum, much greater than a normal saltwater disposal well.

Additionally, as Mr. Wakefield has pointed out, Agave has done no economics on venting carbon dioxide and treating H2S at the plant versus just drilling the acid gas well.

Now, if that doesn't affect Agave either way -- because these are both costs passed through to customers. And if the well is not absolutely necessary, why put Kaiser-Francis and other operators through a risk that they do not need or do not want?

Thus, Kaiser-Francis requests that you deny the application. However, if approval is granted, Kaiser-Francis requests that an order include the conditions Mr. Wakefield set forth in his testimony.

And as a closing comment, I would note that there is little experience with acid gas wells in New Mexico over the long term. Now, the data -- and I guess this is standard -- is to look at a 30-year well life. But there's no guarantee it won't last longer.

As an aside, when I was quite young, decades ago, I was an engineer in the nuclear power business. And back then, going back to the '50s, nuclear power plants were designed for 30 years' life, just like these acid gas injection wells. As I'm sure, as you're aware, there hasn't been a nuclear power plant permitted in the last 30 years in the United States, but there are still lots of nuclear power plants across the country. Now they're projecting the old ones for 60 years' life. I wouldn't be surprised if this was operating for 60 years.

All I'm saying is you've got to be cautious in approving these. Because just to use a 30-year datapoint or something like that doesn't necessarily conform to the facts down the road. Thank you.

CHAIRMAN BAILEY: The Commission will go into deliberations on this case. But we will be looking for findings of fact and conclusions of law from both attorneys by January 9th so that we can sign an order next January.

Do I hear a motion to go into executive session so that we can deliberate strictly and only on Case Number 14720?

COMMISSIONER DAWSON: I motion.

COMMISSIONER BALCH: And I second.

CHAIRMAN BAILEY: All those in favor?

I expect that we will be in executive session for half an hour, maybe, and then lunch. We will reconvene at 1:30 for deliberations on the horizontal wellbore.

(Whereupon the Commission went into executive session.)

(A lunch recess was taken.)

CHAIRMAN BAILEY: The Oil Conservation Commission has been in executive session and broke for lunch. It is time to come out of executive session if I hear a motion to do so.

COMMISSIONER DAWSON: I will motion.

COMMISSIONER BALCH: I'll second.

CHAIRMAN BAILEY: All in favor say aye.

During that time, we discussed only the case before us for Agave Energy Company, and we have come to a decision.

We will grant approval for the acid gas injection well with conditions. Taking very seriously the concerns of the attorney for Kaiser-Francis, we believe that the calculations that were made concerning this well were made with a 30-year life span.

We would require by order that the permit -- the approval for this well will expire 30 years from the date of first injection. And then it can come back to the Oil Conservation Commission for re-permitting, if necessary.

For this approval, Agave is required to re-enter and drill out and plug correctly the following wells: The Simms Number 1, the Government L Com Number 2, the Government L Com Number 1, and the Smith Federal Number 1. If, for any reason, Agave is unable to correctly plug those wells, then they would need to come back to the Commission to discuss that problem.

Mechanical integrity tests will be conducted prior to disposal and prior to first injection. Subsurface safety valves will be installed, and the packers and tubing will be corrosion-resistant.

The order will be signed at the January Commission hearing, but both attorneys for both sides need to submit their findings of fact and conclusions of law by January 9th. Thank you very much for your time.

We are now done with the docket for today, except for deliberations on the rules concerning horizontal well drilling. It is Case 14744, the application of the Oil Conservation Division, Notice of Rulemaking concerning the repeal, adoption and amendments of rules pursuant to the Oil and Gas Act NMSA 1978, Sections 70-2-1 through 70-2-38.

Deliberations on rulemaking are performed in public, as a public discussion. And I think that we need to simply go through line by line and take into account comments that were received. However, the record was closed at the conclusion of the hearing, so the Division's supplemental application will not be considered. Neither will the motion to strike by Jalapeno Corporation, which was a response to the Division's supplemental application.

There are multiple issues that need to be considered, including definitions of project areas, compulsory pooling and well spacing, the number of wells allowed within the area.

So why don't we start with 19.15.14.8? It had to do with the requirement for a permit for an approved permit to drill.

Commissioners, are you on the same page as I am?

COMMISSIONER BALCH: I believe so.

COMMISSIONER DAWSON: I am.