STATE OF NEW MEXICO

ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

CASE NOS: 21020

APPLICATION OF CHEVRON USA INC., FOR A
GAS CAPTURE PILOT PROJECT INVOLVING THE
OCCASIONAL INJECTION OF PRODUCED GAS
INTO THE BONE SPRING FORMATION,
LEA COUNTY, NEW MEXICO.

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

FEBRUARY 6, 2020

SANTA FE, NEW MEXICO

This matter came on for hearing before the New Mexico Oil Conservation Division, EXAMINERS FELICIA ORTH, DYLAN COSS and DEAN McCLURE on Thursday, February 6, 2020, at the New Mexico Energy, Minerals, and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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I N D E X

W I T N E S S E S

E X H I B I T I N D E X

HEARING EXAMINER ORTH: This is Chevron and the well is the Salado Draw and we are expecting four witnesses, direct testimony estimated at 75 minutes.

Mr. Rankin?

MR. RANKIN: If I may I suggest we take a quick break and set up our --

HEARING EXAMINER ORTH: Yes, let's take ten minutes.

(Recess taken.)

HEARING EXAMINER ORTH: Let's come back from the break, please. We have the final hearing for today which is matter 21020, Chevron, the well is Salado Draw.

Mr. Rankin?

MR. RANKIN: Good morning, Madam Examiner. May it please the Division. Appearing on behalf of the applicant in this case, Chevron, is myself, Adam Rankin, with the law firm of Holland & Hart here in town. We have three witnesses today.

One of our witnesses, our land witness is unable to appear due to the inclement weather in -- what was that town -- Midland, she was not able to make her flight. Of course, in light of that we ask that this case be continued after presenting materials today to the March 19 docket so that we can supplement the record with her testimony on land and notice at that time.

HEARING EXAMINER ORTH: Okay. Thank you. Are there any other appearances?

(No response.)

HEARING EXAMINER ORTH: All right. Please go ahead.

MR. RANKIN: Madam Examiner, we have three witnesses who require swearing in.

HEARING EXAMINER ORTH: Where are they? Gentlemen, raise your right hands. Do you and each of you swear or affirm that the testimony you are about to give will be the truth, the whole truth, and nothing but the truth?

WITNESSES: (Collectively.) Yes.

HEARING EXAMINER ORTH: When you come up, I'm going to ask you to state and spell your name.

MR. RANKIN: Thank you.

Madam Examiner, I would like to call our first witness, Mr. Jason Parizek. Jason, as you approach, watch out for the line.

MR. PARIZEK: Okay.

JASON PARIZEK

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Parizek, will you please state your full name

for the record and spell it out for the Examiners.

A. Yes. Jason Parizek, P-a-r-i-z-e-k.

Q. And by whom are you employed?

A. Chevron.

Q. And in what capacity?

A. Senior scientist working on operations team covering the Delaware Basin.

Q. Have you testified before the Division?

A. I have not.

Q. Will you please briefly review your educational background, degrees and your relevant work experience as a petroleum geologist?

A. I have a bachelor of science from San Diego State University, graduated in 2012. Also a master of science from San Diego State University, graduated in 2013. Had a summer internship with Chevron in 2013 where my responsibilities were reservoir characterization between two of our producing fields.

In 2014 I took a full-time position with Chevron out of Bakersfield, California. Responsibilities included reservoir characterization, petrophysical log analysis and planning and developing our heavy oil steam flood operations.

In 2016 I took a position as an operations geologist with Chevron in San Joaquin Valley in Bakersfield, California. Responsibilities included reservoir management and optimization of our heavy oil steam floods and our water disposal operations.

In 2018 I came to Midland working for Chevron on our Delaware Basin operations team. Responsibilities there included uphole recompletions, reservoir characterization, and working on our cross functional team with engineers optimizing production on both our producing wells and disposal operations.

Q. And you have previously -- you are familiar with the application that was filed in this case?

A. Yes, I am.

Q. You conducted a study of the geology and lands that are issue at issue in the area of the proposed application?

A. Yes, I have.

MR. RANKIN: At this time, Madam Examiner, I would tender Mr. Parizek as an expert in petroleum geology.

HEARING EXAMINER ORTH: Are there questions about Mr. Parizek's qualifications?

EXAMINER McCLURE: No questions.

EXAMINER COSS: No questions.

HEARING EXAMINER ORTH: He is accepted.

MR. RANKIN: Thank you very much, Madam Examiner.

BY MR. RANKIN:

Q. Mr. Parizek, let's get into what is being requested here by Chevron in this application.
If you would, there is an exhibit packet before you, and marked as Exhibit Number 1, there is an overview of what the issue is. And referring to that exhibit, will you just generally outline what it is that Chevron is requesting in this application?
A. Yes. Currently our production facilities, we sell our produced gas to third-party systems. Now, when those third-party systems go down for repair or maintenance or any reason, we have two options generally. One is to flare gas in order to continue to produce, or the other alternative is to shut down our operations until the third-party systems come back on line.
Our proposal is, during those third-party interruptions, to occasionally reinject that produced gas into two of our producing wells to avoid those broad shutdowns or/and capture gas that could potentially be flared during the shutdowns.
Once those constraints are lifted, we'll produce back the gas through those same two wells through our existing production equipment.
Q. So just to be clear, what you are asking here is to inject really only small volumes into those two wells for really only short periods of time, and only for so long as

those midstream or market interruptions persist?

A. That's correct.

Q. Now, let's just try a little more context and background, if you would, Mr. Parizek, and explain how your current operations are set up so we can understand what you are proposing with your application.

Referring to Exhibit Number 2, explain what this exhibit shows.

A. Yes. On Exhibit 2 it's a simplified diagram of a typical production operation. So on this diagram there is a blue outline, a parallelogram. The items that are within that are surface equipment. Below that parallelogram is our subsurface equipment.

Looking off to the right side you will see a gray rectangle that represents the wellhead of a typical well that we use, and we produce these with gas lift. Below that you will see our casing strings, and within the production casing, which is the inner string, you will see our tubing going down, and the two gray boxes at the bottom of the tubing represent the packer.

We also have, coming off the tubing in this diagram, are the little J shaped markings, and those represent our gas lift valves.

So under typical gas lift operations, we'd have our gas coming from the compressor, shown by the dark blue polygon that says compressor station. Gas flows from the compressor station through our gas lift flow controller, through the gas lift meter, which measures the rate that we are injecting into the wellhead, and down the tubing casing anulus through one of the gas lift valves where it enters the tubing through a mandrill.

Now, when it enters the tubing, it joins the reservoir fluids that are being produced and that lift gas lightens the tubing gradient allowing the wells to produce.

Those produced fluids will flow up the tubing through the flow line wing valve which is open during normal operations to our central battery which is shown as the gray oval on this diagram.

We also have other wells that are producing in the area, similar to the one I've described, and those flow lines are represented by the thin black lines also flowing into that central battery.

At the battery or at the central battery, those reservoir fluids and the gas lift gas that's produced back with them is separated out into the oil, the water and the gas streams. The water stream is shown by the blue line that extends from the central battery where it will go to a storage tank until it can enter our salt water disposal systems.

The oil will follow the green pipeline kind of represented by the green line in this diagram where it goes into tanks until it can be sold.

And the gas is shown by -- the gas stream is shown by the red line leaving the central battery where it's either sold to third-party systems through a gas lift custody transfer meter or re-utilized in our assets for gas lift injection.

So during a market interruption, we lose the ability to move our produced gases from our facilities into those third-party systems which bottle necks us. Again, the only options we really have at this moment are to flare to produce or to shut in our operations due to that constraint.

Q. Just just to be clear, Chevron, this is diagram schematic representative of both of your proposed producing slash injection wells; is that correct?

A. That's correct, yes.

Q. So for both cases you are currently injecting gas as part of the gas lift operation?

A. That is correct.

Q. So let's talk about what you are proposing to do here with these two applications that would change your operations for these two wells. Refer to Exhibit 3 and explain to the Examiners what you are proposing.

A. On Exhibit 3 we are showing an example of what we are proposing under a gas take-away interruption. So what's the key differences on the surface is now in our producing well that I have described in Exhibit 2, you can see the flow line wing valve is now closed, and the black line that was flowing out from that or the black line extending from that well to the central battery is now gray, showing we no longer have produced fluids flowing out.

Our other flow lines from the other producing wells are still able to produce. Because the produced gas from those wells we are not able to send to third-party systems is now sent from the compressor station to our well that we are proposing to reinject that gas back down into the wellbore.

From a subsurface perspective, the key difference with this operation is now rather than injecting gas down into the tubing and having it flow back up with reservoir fluids, because we've shut in the flow line wing valve, these injected gas will flow down the tubing, below the packer, into the lateral and into the fracture network that's in hydraulic connectivity with the wellbore.

Q. So the only difference here is really operationally, no, no infrastructure equipment changes need to be made or are proposed to be made by Chevron?

A. That is correct.

Q. The only operational change is during shutdown you will simply close that flow line wing valve to ensure

that the injected gas stays within the wellbore and then into the formation?

A. That's correct.

Q. Okay. And just to -- just to recap, I think you alluded to this in the overall purpose here and the goal, but what is it -- why is it that Chevron is seeking to temporarily inject gas in this manner?

A. We want -- we want to reduce our dependency on these third-party systems and have another option or alternative when these systems go down, versus just shutting in our wells or flaring gas, both which result in waste, and, in the case of flaring, results in emissions. This will give us the ability to capture that gas.

Q. Very good. Let's kind of go back over the specific goals here for the project, what you hope to achieve and -- with your pilot project.

A. Yes, sir. Our goals for this project are to determine the injection capacity of each of our wells. We want to the understand what injection rate we can inject in these wells as a function of pressure, and then determine the recovery periods of injected gas after our third-party constraint is lifted and we return these wells to production, we want to get an understanding of how long it takes to recover.

And then finally, assess whether this project can effectively reduce the frequency of shutdowns we undergo due to midstream shutdowns.

Q. So you just referenced Exhibit 4, which is an outline of the four project goals; is that correct?

A. That is correct.

Q. Now, let's see. We referenced that there are two wells here that you were hoping to apply this pilot project to. What are those two wells?

A. It's the Salado Draw 19 26 33 Federal Com 2H, and the SD EA 19 Federal P6 5H.

Q. And where are those wells generally located?

A. Those are located in Section 19, Township 26 South, Range 33 East, Lea County, New Mexico.

Q. Is that depicted in your Exhibit Number 5?

A. Yes, it is.

MR. RANKIN: So I don't have an image of that on the PowerPoint, so I'm just showing a different image that shows the general location on the wells on the PowerPoint for reference.

BY MR. RANKIN:

Q. So the -- and just to, just to clarify that Chevron has determined this as a pilot project because it's seeking to identify the information you have outlined in the goals, and because this is sort of a new operational project, if possible, would Chevron like to replicate, if

it's successful, in a valid concept --

A. Yes.

Q. -- for other wells in area?

A. Yes, we would like to evaluate the use of this in any area impacted by third-party midstream shut-in.

Q. Reviewing what's been marked as Exhibit 6 in your packet, if you would, outline for the Examiners what your time lines are for the main and collecting the data that you hope to collect.

A. Yes. So in the period one to four months from approval, we want to begin to conduct an injection test and acquire data. We will also utilize these pilot wells for occasional short-term injection during any takeaway down time constraints that we encounter.

Four to ten months from approval, we will continue to utilize these pilot wells for occasional injection during takeaway down time. We'll also begin analyzing the data that we are requesting through these periods and start to consider different injection scenarios, primarily different rates if we deem that we can increase our injection rate.

We will start to prepare our post-project report that we plan to submit to the Division eight to ten months from approval.

Q. Very good. Now, did Chevron meet and discuss the

concept behind this project with the Division previously before filing its application?

A. Yes, we have.

Q. What was the purpose of that meeting with the Division?

A. The purpose of that meeting was to seek guidance on how to request approval for this project because the type of injection that we were requesting was not covered in the types of injection currently outlined in Division rules.

Q. In other words, the C-108 does not specifically address or have a process for approving administratively the authorization for injection for this type of temporary gas injection in storage; is that right?

A. That's correct, yes.

Q. So you went to the Division to say, "Hey, we want to proceed with this project. How should we go about it, and what do you want to see from us in order to get approval"?

A. Yes.

Q. Did they prepare for you an outline of the information and conditions that they would like to see identified as an exhibit in the hearing?

A. Yes, they did. They provided us a letter.

Q. That's marked as Exhibit 6 to your packet?

A. I believe it's 7.

Q. All right. Exhibit Number 7, is that the letter that Chevron received from the Division outlining those conditions and information that they would like to see at a hearing?

A. Yes, it is.

Q. So -- so for purposes of reviewing what's in that outline from the Division, what portion are you going to be presenting today?

A. I will be covering the reservoir characterization under Technical Information (i).

Q. In addition, you've reviewed the project description, the duration and time line of the project as well; is that correct?

A. That's correct.

Q. So let's jump into that technical aspect of your testimony today. You prepared a geologic study characterizing the reservoir?

A. Yes, I have.

Q. Let's go ahead and tell us, if you would, what the target injection interval is here.

A. The target injection interval is the Avalon Shale. It's a productive interval within the Bone Spring formation.

Q. If you would, explain to us why it is Chevron identified a Shale, in particular, the Avalon Shale, as its

candidate for this project.

A. Yes. So typically an injection project you seek to inject into a permeable matrix where your injection fluids will migrate away from the wellbore. But in the case of this project, we want to recover the gas, so our objective was to find a reservoir that had an impermeable matrix that would keep that injected gas within the fracture network and close to the wellbore allowing us to recover it.

Q. So counter-intuitively, a Shale, a tight Shale in this case, is exactly what you are looking for?

A. That's correct.

Q. Because you don't want the gas to venture far from your lateral wellbore during the time of injection?

A. That's correct. We want to keep it close.

Q. That's because you want to be able to produce it as soon as the market interruption is over, you can turn around and turn the well back into production and recover that gas?

A. Yes.

Q. Now, you prepared some geologic exhibits sort of providing an overview of your analysis?

A. I have.

Q. Let's go and ahead and turn to your first one here. I believe it should be marked as Exhibit 8?

A. Eight.

Q. That's correct. Thank you very much. Looking at Exhibit 8, will you please outline for the Examiners what your, you know, your overview is of the target reservoir in the area overlying and underlying your injection zone?

A. Yes. As I mentioned, the targeted injection interval is the Avalon Shale. The depth of our injection interval as a TVD or true vertical depth were approximately 9122 feet to approximately 9196 feet. Both wireline log and core analysis indicate the reservoir consists primarily of faintly laminated siliceous silty mudstones, interbedded and interlaminated with argillaceous siltstones, meaning they are rich in clay, and carbonate, thinly bedded carbonates, and carbonates are limestones in this case.

We have air permeability measurements from core that indicate the reservoir matrix permeabilities are approximately 400 nanoDarcies to approximately 5 microDarcies. So these are low, have very low permeability.

The thickness of the reservoir is approximately 250 feet thick vertically, and bottom hole pressures that were acquired in August of 2019 from slick line indicate that after a 12-hour shut-in, the bottom hole pressure is in both our proposed pilot wells are approximately 550 psi and approximately 650 psi.

Q. So those measurements were taken back in August. It might be somewhat less than that today based on

continuous production since that time?

A. That's correct.

Q. Moving on to your next exhibit, let's talk about the -- in more detail about the rock. If you would just review what this exhibit shows.

A. So this is a, this is a map of the Salado Draw area centered on Section 19. It contains all the wells that have been drilled or been permitted, the date of when this created in early December.

Shown in the yellow highlight is the Chevron acreage. The pilot wells are shown by the colored sticks. These represent the trace of the wellbore.

The light blue stick with the large dot which represents the bottom hole location is the Salado Draw 19 26 33, Federal Com 2H.

The black dots on these wellbores, these sticks also represent the surface hole location. The dark blue line represents the Salado -- correction -- SD EA 19 Federal P6 5H.

Also shown on this map is a red line that extends from north to south through the project area. This represents the trace of a cross section that will I'll be showing in a future exhibit. The black circles with red outline represent the locations of the wells that are contained within that cross section.

Q. Go ahead and talk about the next Exhibit Number 9 and what that shows.

A. This is 10.

Q. Exhibit 10

A. What I have is a cross section that extends from north to south. It's a structural cross section through our project area. The tracks that I have -- the well logs that are shown in these tracks from left to right is gamma ray. We have a depth track that's in true vertical depth. Track 2 has resistivity, and Track 3 has bulk density shown in black and neutron porosity shown in blue.

This cross section extends from surface down through our injection interval which is approximately located by the green boxes shown on each of the wells into the Wolfcamp formation.

Like I mentioned earlier, our injection interval is approximately 9122 feet TVD to approximately 9160 feet TVD. The Rustler formation is shown towards the top of the cross section. The underground sources of drinking water occur above this pick, and it is approximately 8,500 feet shallower than our injection interval.

The confining layers above and below our injection interval are the Bone Spring Lime, which is approximately 55 feet thick, and I will show an expanded cross section in a future exhibit. And below our injection interval there is interbedded tight carbonates with interbedded tight mudstones that confine it below the injection interval.

Q. So in this map, those are the most -- those are the immediate confining layers; is that correct?

A. That's correct.

Q. You have you additional zones that function as impermeable barriers above your injection?

A. That's correct.

Q. Would you point those out for the Examiners as you reference the exhibit?

A. Yes. So between our underground source of drinking water and our injection interval, we have approximately 4,250 feet of the Delaware Mountain Group which is comprised primarily of sandstones, interbedded with siltstones and minor carbonates.

The upper portion of the Bell Canyon Formation is productive within the general area of Salado Draw. Above that is approximately 1800 feet of anhydrite interbedded with halite which provides an impermeable barrier of fluid migration upwards.

Above the Castile is the Salado Formation, which is approximately 1,850 -- or 1,800 feet of salt which also provides an impermeable barrier for fluid migration upward.

Q. You've indicated on this cross section the

approximate target interval in green highlighting. Is that correct?

A. That's correct.

Q. It's a little hard to see in this image, so you have created a blowup to make it easier to read your target injection zone. Is that your next exhibit?

A. Yes, it is.

Q. Will you review what that one shows and the explain the significant aspects of it?

A. Yes. So Exhibit 11 is that same wells, but it's an expanded view of our -- above and below our injection interval. In addition to that, I also added the density porosity curve in Track 3, and that curve is shown in red.

So above our injection interval we have the Bone Spring Lime, log characteristics of this zone, low gamma ray, high resistivity and the neutron porosity and density porosity track together at approximately zero to 2 percent porosity.

In addition, the bulk density is approximately 2.7 grams per cubic centimeter. All of these characteristics are indicative of a tight carbonate. Within our injection interval, the gamma ray is relatively higher than we saw in the Bone Spring Lime. The resistivity is lower than we see in our porosity track, the separation between the neutron porosity and the density porosity.

Also the bulk, the bulk density is approximately 2.5. These log characteristics are indicative of a mudstone that contains clay. Below our injection interval we have interbedded mudstones and thick carbonates with log characteristics that I had mentioned from the Bone Spring Lime and our injection interval. These tight carbonates above and below our injection interval will provide containment for our injection -- injected gas from migrating from the formation.

Q. Very good. And you prepared some additional exhibits further characterizing the, not just the reservoir, but the overlying and underlying strata. What's been marked as Exhibit Number 12, what does that show?

A. This is a structure map of the top of the Bone Spring Lime, so it's our same base map shown in the prior exhibit. What it shows is the Bone Spring Lime dips approximately 1 to 2 degrees east over the project area.

Q. And what is the significant takeaway from this overview just showing the general structure? Are there any interruptions or geologic impediments or breaks or faults that would interfere with Chevron's ability to inject gas in this area?

A. No, there are not.

Q. There are no faulting or other conduits that would cause gas to escape the injection zone?

A. No, there are no conduits to allow gas to migrate from the injection interval upwards through this Bone Spring Lime.

Q. Very good. Looking at your next exhibit, what does it show, Number 13?

A. Exhibit 13 shows an isochore or the true vertical thickness of the Bone Spring Lime over the general area. As you can see from this exhibit, it shows that within the broader area around Salado Draw, it generally is thick to the west and it thins out to the northeast.

Over the project area, the Bone Spring Lime is approximately 45 to 55 feet thick, and it is continuous, is present across that project area.

Q. And in your prior testimony when you were discussing the structural cross section, the Bone Spring Lime is the immediate confining area overlying this injection; is that correct?

A. That is correct, yes.

Q. So you have 40 feet of essentially impermeable barrier containing the gas that you inject?

A. That's correct.

Q. Very good. Looking at what has been marked as Exhibit 14, what does this show?

A. This is a structural cross section of the top of the Rustler Formation, so the underground source of drinking water is above the top of the Rustler. The Rustler is one of the more regionally correlative surfaces, land utilizing that. Like I said, the underground source of drinking water is above it.

Over the project area the Rustler is relatively flat line, and if you look to the left side or the west of this diagram, you will see that it dips off to the west, and this is representative of the eastern edge of the Pecos Trough.

Q. And the point of this map is to show just the structure of that fresh water, the bottom of that potential fresh water zone?

A. That is correct, yes.

Q. What is your next map, Exhibit 15?

A. The next map is an isochore or true vertical thickness between the top of the Rustler to the Bone Spring Lime, the Bone Spring Lime being the confining layer above our injection interval.

The purpose of this exhibit is to show that it's approximately 8,250 feet between those two surfaces I mentioned, and that interval is relatively continuous thickness and is not interrupted by major features or geologic features that would prevent migration of injected fluids up from the injection interval to the underground source of drinking water.

The thinning you see to the west is representative of the dip in the Rustler structure and due to that Pecos Trough that I had mentioned.

Q. Again, just referring back to your structural map, you've got approximately 8000 feet of vertical offset between the bottom of the potential fresh water zone and your injection interval?

A. That is correct, yes.

Q. And interbedded within all of that is the multiple impermeable barriers that you offered during your testimony on the structural cross section?

A. Yes.

Q. Very good. Now, have you formulated an opinion and a conclusion about whether or not this project will be protective of underground sources of drinking water?

A. I have.

Q. Referring to your slide marked as Exhibit 16, can you review for the Examiners what the issues are about the potential drinking water sources?

A. Yes. So the source of underground -- or the underground source of drinking water is the Pecos Valley Aquifer. We have one well within a two-mile buffer around Section 19.

The depth of that well is 160 feet. The depth to water is 120 feet. And the New Mexico Office of the State

Engineer Water Rights file number is C02773 for that particular well.

I discussed the injection interval and the impermeable tight carbonate that overlies it, that Bone Spring Lime. Overlying the Bone Spring Lime is the Delaware Mountain Group, which is approximately 4250 feet thick. It contains, as I mentioned, connate water bearing sandstones, and hydrocarbon bearing sandstones, interbedded with siltstones and minor carbonates.

Above the Delaware Mountain Group is the Castile Formation. It's approximately 1800 feet thick, comprised of anhydrite, calcite, gypsum and salt beds that are impermeable and act as another competent barrier to upward fluid migration.

Above the Castile is the Salado Formation. It's also approximately 1850 feet thick, comprised primarily of salt, which provides another impermeable barrier for fluid migration upwards.

Overlying the Salado is the Rustler Formation. It's approximately 350 feet thick, comprised of anhydrite, shale, siltstone, sandstone and minor halite. Overlying the Rustler is approximately 700 feet of the Dewey Lake Formation and the Pecos Valley Alluvium which is an underground source of drinking water.

Due to the thickness and multitude of impermeable barriers overlying the injection interval, I do not see or do not anticipate a path of migration upwards into the shallow water aquifer.

Q. Based on your geologic analysis, have you also reached a conclusion and opinion about whether or not the gas that Chevron proposes to inject into the two wells will be contained within the injection interval?

A. I have.

Q. Reviewing your next slide marked as Exhibit 17, will you review for the Examiners your conclusions regarding containment of the gas and the basis for your opinion?

A. Yes. Overlying the injection interval is the approximately 50 foot thick Bone Spring Lime. It's a tight carbonate and it will provide a barrier for upward fluid migration. Below the injection interval we have interbedded carbonates and mudstones -- I should say tight carbonates and mudstones that will provide a barrier for downward fluid migration. This interval is approximately 750 feet thick.

Laterally the injection interval is expected to be contained primarily within the conductive frac network or fracture network that's in connectivity with the rock, and due to the low permeability of the matrix, we do not anticipate migration of injected gas out of the fracture network into the matrix.

Q. So we talked a lot about and looked at your

structural cross section, the fact that there are impermeable barriers above and below. And here, we are talking also now about laterally containing the gases or containing it near wellbore to your injection site, and that's based on your assessment that these -- the injection interval here is very tight; is that right?

A. That's correct, yes.

Q. In other words, there is not opportunity for the gas to escape through porous or other geologic mechanisms from point of injection?

A. That is correct, yes.

Q. Okay. And now, will there be other witnesses who will be testifying on reservoir engineering analysis that support your geologic conclusion as well?

A. Yes, that's correct.

Q. Okay. Is that everything that the Division has required in terms of reservoir characterization on the geologic side?

A. Yes, it is.

Q. In your opinion, Mr. Parizek, will the granting of this application be in the interest of preservation of -- prevention of waste and the protection of correlative rights?

A. Yes, it will.

Q. In your opinion, will this project be able to be

operated safely without presenting risk to human health and the environment and to underground sources of drinking water?

A. Yes, it will.

Q. Were Exhibits 1 through 17 prepared by you or under your direct supervision?

A. Yes, they were.

MR. RANKIN: At this time, Madam Examiner, I would move the admission of Exhibits 1 through 17 into the record.

HEARING EXAMINER ORTH: Exhibits 1 through 17 are admitted.

(Exhibits 1 through 17 admitted.)

MR. RANKIN: No further questions, and pass the witness.

HEARING EXAMINER ORTH: Thank you. Mr. Coss, any questions?

EXAMINER COSS: Yes, I do. I don't have many questions, but I do have a few. Good morning, Mr. Parizek. Nice to see you again.

THE WITNESS: Thank you. You, too.

EXAMINER COSS: Thank you for your presentation. It was fairly informative. And one of the questions I have is why did Chevron choose the upper Bone Spring or Avalon Shale among all the other formations to test it as a pilot project?

THE WITNESS: This is an area that we have a lot of interruptions due to third-party takeaway. The bottom hole pressure in these wells are low enough that we can inject into the fracture network where there is existing facilities. And these are -- the reservoir properties of this area are ideal for this type of injection, mainly primarily the low permeability matrix. We have -- we expect that the injected gas will stay within the fracture network due to the tight matrix.

EXAMINER COSS: Perfect. So is it Chevron's opinion that -- is it just that the permeability numbers are low, or does the composition have any role to play in this, or the thickness of the interval or the bedding of the reservoir have any role to play in suitability?

THE WITNESS: The ideal characteristics of this injection interval are the low permeability rock matrix, and as Dr. Yula -- or Dr. Tang will mention, also that the matrix pressures are higher than our injection bottom hole pressures. So we don't expect injected gas to migrate from the formation.

EXAMINER COSS: I see. So is the Avalon Shale a much better target than the middle Bone Spring or the lower or the Wolfcamp?

THE WITNESS: The matrix permeabilities of the

Avalon Shale are ideal versus a more permeable sandstone, yes.

EXAMINER COSS: Sure. Say this were, this project were to expand into the future with other operators, does Chevron see any problems -- what problems might they foresee if someone would propose doing this on a Wolfcamp horizontal well?

THE WITNESS: A Wolfcamp well, it would be very similar to the characteristics we see in the Avalon, so this would be a project that would be easily adopted into a Wolfcamp formation.

EXAMINER COSS: Those are all my questions.

HEARING EXAMINER ORTH: Mr. McClure, any additional questions?

EXAMINER McCLURE: Yes, I do. This may be a question better for your landman, perhaps. If so, let me know.

Has there been communication with the Bureau of Land Management in regards to this pilot project?

THE WITNESS: We did have a meeting with the Bureau of Land Management and they were supportive of this concept.

EXAMINER McCLURE: Okay. That answers that question. I guess -- and this could be a better question for the reservoir engineer, so let me know. As far as the extent of the height of your fracture, do we know where the top of your fracture network is, and do we have reason to suspect that that is the top?

THE WITNESS: I don't have modeling. What we do have is indirect evidence from empirical data. We do not see a high water production in these wells. The water oil ratio is approximately one, and we have low total fluid production, approximately 40 to 50 barrels a day.

So we don't have -- we would -- we do not expect that we have fractured through the upper confining layer. In that case we would expect to see high water production and very high water cuts from these wells. We would also not -- expect that we would not be able to draw down the reservoir pressures to what we have seen from those tests that we have done back in August.

EXAMINER McCLURE: I agree. So basically -- but the thought process is the Bushy Canyon would be a significantly higher water producer if you fractured into that basically.

THE WITNESS: That is correct, yes.

EXAMINER McCLURE: And that actually extends a little bit to my next question which may not be relevant if you are not fractured into it. The Bushy Canyon is not productive in this immediate vicinity; is that correct?

THE WITNESS: That's correct.

EXAMINER McCLURE: Okay. And this may be a question again that might be better for the reservoir engineer. As far as a volume for your fractured network, is that a part of what you're trying to figure out from this, this pilot project, or do you have rough estimates as to how much gas capacity for storage you have within the fractured network?

THE WITNESS: Dr. Tang will cover that in his testimony.

EXAMINER McCLURE: That sounds good. I'll withdraw that question for now.

I believe I had another question, but for some reason I did not write a note on it.

As far as shut off equipment to ensure that your maximum allowable surface pressure does not exceed the 1250 I believe that you are requesting, do we have some sort of shut-off valve at the wellhead, or is that going to be controlled back at your artificial lift pressure station?

THE WITNESS: We have both, and Mr. Acero will provide additional detail on that.

EXAMINER McCLURE: Okay. Sounds good, and I will ask more later. I believe that's all the questions I have for you.

HEARING EXAMINER ORTH: Anything further, Mr. Rankin?

MR. RANKIN: Nothing further. I ask that Mr. Parizek be excused so we may call our second witness.
HEARING EXAMINER ORTH: All right. Thank you, Mr. Rankin, Mr. Parizek.
MR. RANKIN: With that, Madam Examiner, I would like to call Dr. Yula Tang to the stand.

YULA TANG

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good morning, Dr. Tang. How are you today?
A. Good. Thank you.
Q. Will you please state your full name for the record and spell, for the benefit of the court reporter.
A. Yes. My name is Yula Tang. T-a-n-g is my last name.
Q. And your first name is spelled?
A. Yula, Y-u-l-a.
Q. Thank you very much. By whom are you employed?
A. With Chevron.
Q. And what is your current position with Chevron?
A. I'm the senior production engineer advisor.
Q. What do your job obligations include in that capacity?
A. I cover all the reservoir engineering and

production engineering aspects for the technical issues.

Q. That includes in the Permian Basin in New Mexico?

A. That covers the Delaware Basin.

Q. Delaware Basin. Have you previously testified before the Division?

A. No.

Q. Will you please review briefly your educational background and your relevant experience as a reservoir and petroleum engineer?

A. Yes. I graduated from Southwest University China with petroleum engineering bachelor's degree, and I taught at other faculty in the university teaching production engineering for 12 years. And I come to the US, University of Tulsa, Oklahoma, to get my master and Ph.D. in petroleum engineering.

And since then I join Schlumberger Service Company for well completion, and I did 12 years -- five years in flow assurance with a Norwegian Company, Standard Petroleum Technology, before I joined Chevron in Houston doing the -- in the research company, Chevron Technology -- Energy Technology Company, ETC, and I do the well modeling performance on the global operation for Chevron.

Then since 2008 I worked overseas for Chevron, part in China on a -- for total more than 18 years, and I come back a year in between. I work in Houston to support the Permian Basin Oil Development as a senior reservoir engineer advisor in Houston for three years. And I come to work in Midland last year, June last year, so as the current position.

Q. Have you conducted a study, an engineering study of the reservoir in the area of the -- in the vicinity of the proposed pilot project area?

A. Yes.

Q. And you're familiar with the application that was filed in the case?

A. Yes.

MR. RANKIN: At this time, Madam Examiner, I would tender Dr. Tang as an expert witness in reservoir and petroleum engineering.

HEARING EXAMINER ORTH: Are there questions about Dr. Tang's qualifications?

EXAMINER McCLURE: No questions.

EXAMINER COSS: Not questioning his experience, it's more than adequate, but what did you research for your Ph.D? What was your topic.

THE WITNESS: My Ph.D was horizontal well compilation optimization coupling with a wellbore.

MR. COSS: Just curious. Thank you.

HEARING EXAMINER ORTH: Thank you. He is so recognized.

MR. RANKIN: Thank you very much, Madam Examiner.
BY MR. RANKIN:
Q. Dr. Tang, in your exhibit notebook in front of you, marked as Exhibit 7 is a letter from the Oil Conservation Division to Chevron; is that correct?
A. Yes.
Q. And in that letter they identified some additional information and characterizations that they requested Chevron perform at hearing. Have you prepared, in response to that request, an analysis and testimony regarding technical items from sub-Roman Numeral (ii) and (iii)?
A. Yes.
Q. And those relate to reservoir modeling and evaluating potential impacts from the reservoir's ultimate recovery.
A. Yes.
Q. Very good. So let's, let's jump into your analysis. If you would, Dr. Tang, looking at Exhibit Number 17 -- 18 in your exhibit packet -- I believe it should be 18.
A. Yes.
Q. If you would, just review for the Examiners how you modeled the reservoir in this case.
A. Okay. So in this case we did material balance

model. We call it the MBAL, material balance. That is a tank model to evaluate the injection capacity and also the injection pressure and reservoir pressure change during the gas injection into the reservoir.

So we use the industry software Harmony. We call it the rate transient analysis or RTA, to estimate the reservoir tank size or the stimulated reservoir size or the stimulated rock volume, SRV.

So we use the two different analysis to evaluate the SRV tank size, which yield the consistent results for the tank size. Then we use the SRV tank size and the matrix tank size that are connected with each other by transmissibility, and then we match the production history since 2016 for this well.

So we match the production decline and the pressure decline, then we focused our maximum 14 days, two weeks injection into the reservoir for the gas and to see how that -- how we can achieve that. So in the model we considered an injection of 2 million of gas of per day, and we considered a constant of 1100 psi, which is less than the 1200 psi maximum operation pressure, and considered maximum 14 days injection.

So the result shows us that from the tank model, the gas injection results in slight pressure increase in the reservoir and the wellhead. And we also covered the uncertainties with a sensitivity study to address the model regarding to the tank site, regarding to the injectivity, which we will show later in the, in the next few exhibits.

Q. So before we move on, I just want to make sure that we are on the same page in understanding what you did.

So first, Dr. Tang, if you would, just explain a little more about how -- what a material balance model is and how -- what you mean by tank. And in this case, what were the tanks that you created in your modeling?

A. So the material balance is basically consider how much from the production point of view, that is, how much you produced then accordingly based on the physics, then the reservoir pressure will decline. Also, on the ultimate, if we inject into the reservoir, then based on the physics, how the reservoir pressure will change here, and, accordingly, how much you can inject into the reservoir.

So we describe the reservoir as a tank, and in this model we not only considered near well lateral tank because that's the hydraulic fractured stimulated rock, so what we call SRV tank, also we consider the far away connect -- that connect to the SRV tank, that is original, original matrix, that is very tight reservoir, but the pressure will be much higher.

So these two tanks were interrupted with two of the models to match our decline of the bottom hole pressure were made and the surface pressure and the -- so that's the way we talked to the physics to try to answer, to address our injectivity volume and the pressure change.

Q. So essentially there is two tanks, one is the SRV, which is the stimulated reservoir volume, is one. The other is the matrix, which is the lateral component of your injection zone that remains in native condition, essentially, with high pressure?

A. Yes.

Q. So you are looking at the effect of both production and injection on the interaction between those two volumes.

A. Yes.

Q. Okay. So now, let's -- now that we understand the concept, let's look at what the results are.

And would, Dr. Tang, on your next exhibit here, 19, if you would, just review for the Examiners how the model was constructed. We talked a little bit about it conceptually, but if you would, referring to this exhibit, explain how your model was constructed and each of the elements it comprises.

A. Yes. So this model, so we have injection source, that's the gas water injection for maximum of two weeks, and then injection rate of 2 million for this case. And this is the injection well. So before injection it is a production well. So we actually injected into the production well, it already produced for about four years.

So this injection -- this injection wellbore SD 19-2, Salado Draw, that has linked to the reservoir SRV tank by the diamond. This diamond will present injectivity.

We have the -- that means before April 1 in this model, we make assumptions, we have this well is producing. This is the production, on the production. But after April 1, we inject fluids so we get the injection rate of the reservoir that is 2 million gas injection.

And the SRV tank, it is linked to the tank, the reservoir tank, that is the matrix tank. And by -- we have that connectivity use the transmissibility to link to the both tanks, the pressure and the bulk.

And in this model, so we basically we have that -- and we can show this. This is our model result. So this black line shows the liquid rate, the water and the oil total. So during the production before our injection, this is our original rating on the left axis, vertical axis, average is 40 barrels only, so it's very different.

If we look at back at the beginning 2016, the well produced only about 1000 barrels, but now we were only 20 barrels, water 20 barrels, so total only 40 barrels. It's declined. It continues to decline with gas lift injection.

So we have this gas lift injection about 4.8 million gas injection. On the -- it still, the reservoir, SRV tank pressure declines. This is about a 650 psi. It continues to decline during the production.

On the matrix pressure it shows here it's about 2500 psi, and also basic slight decline, but it is higher, much higher than the SRV tank next to the wellbore. So that matrix tank is a continuous charge into the SRV tank here.

Then in the model, we assume from April 1 that we start injecting gas into the reservoir, and accordingly the bottom hole pressure will increase because we are injecting into this reservoir. And also the SRV reservoir pressure will also increase slightly. The SRV tank pressure will increase about, about 100 psi during this injection period.

So that's all this, this exhibit is about.

Q. Okay. So the diagram on the left is essentially a representation, a schematic of how the model was constructed. It is the model?

A. Yes.

Q. And then the graph on the right are the results of that model, reflecting the interaction between the matrix tank and the stimulated reservoir volume tank?

A. Yes.

Q. Once you -- during production and then when you turn on injection?

A. Yes.

Q. Just to clarify, the values that you use here, the parameters that you mentioned previously, the 1100 psi, the approximately 2 million cubic feet of gas per day, that's a base case. And by base case you mean that is a, a potential average of what you might expect to inject in these wells?

A. That's correct.

Q. But not a limit. So Chevron, if it could, potentially it could inject more gas than 2 million?

A. That's right.

Q. And your limitation here is just going to be what your maximum allowable surface injection pressure is going to be essentially; is that correct?

A. Right.

Q. Okay. Now, I will talk a little bit more about that with the last witness. Now, in addition to your model here -- we are going to talk about your results -- you also testified that you looked at some sensitivities in the model; is that right?

A. Yes.

Q. So let's talk about that. Looking at your next slide here, what the sensitivities are that you looked at. Can you explain for the Examiners what you mean by sensitivities and what you looked at and what this slide

shows for Exhibit 19?

A. Okay. So as we mentioned before, we have uncertainty in the reservoir regarding to the SRV tank size regarding to the injectivity. So here we change the tank size by -- by 50 percent. So from the original tank size of the gas volume in the tank, about 200 million, we change it to -- from the base case 200, to the initial case of 100 million volume for the tank size.

Then we review, after the injection, we want to see how that pressure changed. The base case of the red line, that is SRV result pressure, which increase to -- from 600 -- more than 600 psi in the beginning to about 1200 psi. Under the sensitivity case, by using a reduced tank size, that pressure for SRV will increase less than 7 -- 800 psi at the end of the injection.

And accordingly, the bottom hole pressure, the flow and bottom hole pressure and injection pressure for the base case, it slightly increased, and for the sensitivity case of 100 million gas volume SRV size, that has increased a little more, so it will be like 1050 psi accordingly.

Q. So to just sort of put this into more laymen's terms, what you are looking at here is to say, even if you're wrong and you've overestimated the volume in the fracture network by, by twice, and it's only half as voluminous, you are showing that there is not going to be

substantial shift in the down hole pressure or in the response in the stimulated reservoir volume pressure; is that correct?

A. Yes.

Q. Okay. And that's just -- why is that, do you think? Is that because it has to do with how much volume has been removed from the reservoir to date?

A. Yeah. The reason that this slight increase is because the injection volume is very small comparing to we already have the gas volume in the SRV reservoir tank and wellbore connected by the hydraulic fracture, many state hydraulic fractures.

That fracture, that have SRV based on, as I mentioned before, we use the RTA that I trace the Harmony on -- to give us a need for a numeric estimation. So when those uncertainties we change it that cut it by half, we see all that pressure will change.

Q. Very good. So then there was another sensitivity you analyzed as well.

A. Yes.

Q. Which is that one? Looking at your next exhibit here, Exhibit 20, what does that show?

A. So the next exhibit we did is injectivity. That means how good is the well when we inject the gas into the reservoir. So we have a base case of injectivity based on our -- our -- the permeability on the RTA.

So we use that injectivity from the 100 percent injectivity as the base case to 50 percent injectivity. So if we reduce the base case to the 50 percent injectivity, then that bottom hole pressure, the injection will increase from here at the end of injection for about 1000 psi. It will increase 200 psi from 1000 to 1200 psi.

So that's, if you have a poor injectivity, then you will make it a hazard to inject, so the bottom hole pressure accordingly will increase. But for the reservoir size itself, once you have injected that same model for that 2 million for 14 days, then the reservoir size is the same size, so the reservoir size for this is unchanged.

We only change one variable, that's the injectivity so that the bottom hole pressure will accordingly increase 200 psi. But the surface pressure, its injection pressure will still be much less than our normal injection pressure of 1100 psi, much less than the 1250 psi maximum pressure.

Q. Even if you're off in your estimates or assumptions about what the injectivity is by half, you will still be able to achieve this project --

A. Yes.

Q. -- as you have designed it?

A. Yes.

Q. One other aspect I meant to ask you. For your base case here, you have selected a time frame of 14 days for your injection. What's the basis for choosing the 14 days for that as your base case?

A. This is based on our statistics over the past of what happened. Normally it's about several days, couple of days, maximum about a week. So we just used the -- expect the maximum period that we have to inject it into the -- into that well for two weeks only.

Q. So even on the outside, you only see interruptions that last no more than a week, more like days, but here, to be conservative, you are choosing a 14-day time frame as your base case?

A. Yes.

Q. And even under that extended period of time for injection, you are not seeing any issues in terms of being able to achieve the injections and volumes you are proposing?

A. Yes.

Q. Okay. So, Dr. Tang, thank you very much. Based on your analysis and running of your model and looking at the sensitivities, is it your opinion that the model results suggest that the Avalon Shale is a good candidate for this pilot project?

A. Yes.

Q. And it's suitable for purposes of injecting gas for temporary time frames?

A. Yes, it is.

Q. And in your opinion, is it, is the gas that Chevron proposes to inject likely to migrate beyond the injection interval itself?

A. No. It will be maintained in the SRV area.

Q. Is that -- I'm going to flip back to the slide, the model results. What are the factors that help contain, besides the geologic factors that Mr. Parizek testified to, what are the reservoir factors that are going to help maintain the gas injected to the near wellbore area?

A. The original factor I think is that the SRV area that has the permeability, by stimulating it to the -- hydraulic fracture stimulated, that permeability is much higher, so that pressure is much lower. But the original version reservoir, that rock is like very tight, as mentioned in the beginning, our geologist mentioned that the original matrix permeability is very low. So that matrix permeability pressure is very high, so that will maintain our injection gas through the SRV volume or in the hydraulic fracture only.

Q. So looking at your results where you see that large differential between the matrix reservoir pressure, the green line, and your SRV pressure, the dark blue line,

that differential is what you are talking about, that matrix pressure is going to keep that injected volume of gas near to wellbore within the stimulated rock volume area?

A. Yes, that is.

Q. Okay. And in your opinion, based on that, do you believe that there is a -- that the injected gas will interfere with other offsetting wells in other zones or within the Avalon Shale itself?

A. We don't think it will go out to an upper or lower zone, but what we are going to do -- that's why we are doing the pilot, to prove or observe the offset well that any interruption between once we start injection, and other wells, the pressure change or production change.

Q. And Chevron operates the offsetting wells, so it will be able to monitor the effect of this injection as it's happening?

A. That's right.

Q. Okay. Now, have you also conducted an analysis of whether the injected gas will have a net positive neutral or negative effect of ultimate recovery within the Avalon Shale?

A. That is showing that it's a -- so as we mentioned, this injection volume is very small compared to the rock SRV size and the deep original one was less than 3 percent. So this would not impact the oil production significantly.

And also the lower -- the low pressure injection is significantly below the visibility pressure. The gas will not dissolve into the oil, so that will not -- that will not modify the oil properties.

So accordingly, based on this assumption, we are expecting the impact on the EUR will be neutral, will not increase significantly or decrease significantly oil production in the future.

Q. And you -- I just want to point out in your first response here on the EUR impacts, you state here that the estimated injection is going to comprise less than two percent of the reservoir volume already extracted or produced. So that has a lot to do with the ability and why Chevron chose these wells for this project; is that correct?

A. Yes.

Q. Now, Dr. Tang, in your opinion, will granting this application be in the interest -- will it prevent waste and will it protect offsetting correlative rights from other operators?

A. Yes.

Q. And in your opinion, can this pilot project be operated safely without presenting -- presenting a risk to human health or the environment, including sources of underground drinking water, in your opinion?

A. Correct.

Q. Now, were Exhibits -- I believe it's 17, maybe -- I'm sorry, 18 through 21 -- is that correct?

EXAMINER McCLURE: 22.

Q. 22, thank you very much. Prepared by you or under your direction and supervision?

A. Yes.

MR. RANKIN: At this time Madam Examiner, I would move the admission of Exhibits 18 through 22 into the record.

HEARING EXAMINER ORTH: Exhibits 18 through 22 are admitted.

(Exhibits 18 through 22 admitted.)

MR. RANKIN: I have no further questions and pass the witness to the Examiners for questions.

HEARING EXAMINER ORTH: Thank you. Mr. Coss, any questions of Dr. Tang?

EXAMINER COSS: You know what, Mr. Tang, I thank you for your testimony, and it was -- it covered enough material that the questions I had were answered along the way, so thank you for that, and I will pass the witness.

HEARING EXAMINER ORTH: Mr. McClure?

EXAMINER McCLURE: Yeah. Actually I'm with Dylan, you did answer a lot of my questions as well. I was going to say one thing, just out of curiosity, you used the production history solely to determine your fractured network volume, or is there any well tests that were conducted in addition to that?

THE WITNESS: We presently use the decline -- on RTA, so that's our major tool. That's what we used.

EXAMINER McCLURE: Okay. I'm with you. I'm with you. I guess, is that typically a pretty accurate way of getting that determination of that volume?

THE WITNESS: That's right.

EXAMINER McCLURE: Okay. Okay. Any questions I may have that may be better answered by another witness, just let me know and I will withdraw them for now.

Approximately how many wells would 2 million cubic feet a day cover as far as Chevron's production in the local area, in as, how many injection wells would a person need to -- to cover your production wells?

THE WITNESS: So, so basically what we use the 2 million as a start point. We don't know, we can go, maybe we can even inject more, probably up to 5 million. So that's why we need to do the pilot test with the injection, how much, you know, when they start the process, if their pipeline cannot take our gas, then we will see if we can use the two wells to take our gas capture for that temporary period.

EXAMINER McCLURE: Oh, I apologize. I'm

completely with you there. I guess what my question was, I'm not sure what the typical gas production is of the offset wells herein as, can this handle the production from 20 wells for that two-week period, or do you need one every 10 wells to eliminate flaring entirely and go completely to injection?

THE WITNESS: I think our production engineer --

EXAMINER McCLURE: Would be better suited?

THE WITNESS: To tell specifically how much our total production on the impact that --

EXAMINER McCLURE: I will withdraw that question for now. Thank you. This is probably another one that's better -- the economic limit for this well, is that a better question for a later witness as well?

THE WITNESS: Yes.

EXAMINER McCLURE: Okay. Let's see. You already answered this question.

Are we assuming pretty much zero percent injection from your fracture network into your matrix then over this two-week period?

THE WITNESS: That's right.

EXAMINER McCLURE: So all your injectivity was purely into your stimulated reservoir volume then?

THE WITNESS: Yes.

EXAMINER McCLURE: Okay. And all the pressures we are looking at here are your bottom hole pressures; correct?

THE WITNESS: Yes.

EXAMINER McCLURE: Okay. Are we presuming a fluid density of about .14 pounds per foot, or do you know?

THE WITNESS: Our production engineer will provide you that.

EXAMINER McCLURE: Okay, thank you. I believe that's all the questions I have for now. Thank you.

THE WITNESS: Thank you very much.

HEARING EXAMINER ORTH: Thank you, Dr. Tang.

MR. RANKIN: Thank you very much, Madam Examiner. We can happily push on if you would like to get this done. I think it would probably take us another 25 minutes or half an hour for questions.

HEARING EXAMINER ORTH: All right. Thank you, Dr. Tang. I'm going to ask the gentlemen, what's your preference?

EXAMINER McCLURE: It don't matter to me. I don't get to go take lunch, anyway.

MR. COSS: It's up to you then.

HEARING EXAMINER ORTH: Should we press on?

All righty, Mr. Rankin.

MR. RANKIN: Thank you very much, Dr. Tang, you may be excused. Madam Chair, at this time I would like to call our third witness and final witness of the day, Mr. Edgar Acero.

EDGAR ACERO

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good afternoon, Mr. Acero. Would you please state your full name for the record, and spell your name for the court reporter, please?

A. Edgar Acero. It's E-d-g-a-r. My last name is A-c-e-r-o.

Q. Thank you. Mr. Acero, would you please state by whom you are employed?

A. Chevron.

Q. In what capacity?

A. A senior production engineer.

Q. Do your responsibilities in that role include oversight of this proposed pilot project?

A. Yes.

Q. And have you previously testified before the Division?

A. Yes.

Q. And in light of the fact we have new Examiners, would you please briefly summarize your prior education and work experience as a production engineer?

A. Yes. I graduated from the University of Texas at Austin in 2002. In 2002 I joined KBR, which is an engineering firm, and I worked there as a facilities engineer.

And in 2006 I joined Chevron as a facilities engineer. And in 2009 I became a production engineer. And that is my current role, which is managing the production operations in the field.

Q. Have you reviewed the application in this case?

A. Yes.

Q. You are familiar with what Chevron is proposing?

A. Yes.

Q. Have you conducted a study of the design of the well and the offsetting wells what surround the proposed pilot project area?

A. Yes.

MR. RANKIN: At this time, Madam Examiner, I would tender Mr. Acero as an expert in production engineer.

HEARING EXAMINER ORTH: Any questions about his qualifications?

EXAMINER McCLURE: No questions.

EXAMINER COSS: No.

HEARING EXAMINER ORTH: Thank you. He is so recognized.

MR. RANKIN: Thank you very much.

BY MR. RANKIN:

Q. Mr. Acero, if you would just flip to what's been marked Exhibit 7 of your exhibit book. That is the letter that was sent to Chevron from the Division. In that letter are a list of topics and conditions that Division requested Chevron prepare for this hearing.

Will you be addressing items, technical items sub-Roman Numeral (iv) through (x); is that correct?

A. Yes.

Q. Have you, then starting with first item on that list, item sub-Roman numeral (iv), have you prepared a wellbore diagram for each of the wells that are proposed for injection in the application?

A. Yes, I have.

Q. And will you review for the Examiners what that exhibit shows? I believe it is Exhibit Number 23 -- I'm sorry, 24, yeah -- no, 23. Sorry, 23.

A. Yes. This is a wellbore diagram of the Salado Draw 19 26 33 Federal Com 2H. What this includes is the well name. It also includes the location of the well, the API number. It includes the formation tops.

And it also includes details on the surface casing, intermediate casing, production casing, and the production casing does show the top of cement as well. Also included in the wellbore diagram are the locations of the gas lift valves, because this is a gas lift well, and it also includes the perforations, the TVD.

Q. Very good. And on the second page of that exhibit is, do you have the wellbore diagram for the second well that is part of this application?

A. Yes.

Q. Will you review that diagram and what it shows?

A. Yes. This is a wellbore diagram for SD EA 19 Federal P6 5H, and it's also includes the location of the well, the well name, includes the top of formation, includes a description of the surface casing, intermediate casing and production casing, also the top of cement. Includes the depth of the gas lift valves and the perforations, TVD and empty.

Q. And also requested by the Division is a copy of the drilling reports. Is a sample of the drilling reports included and marked as Exhibit 24?

A. Yes.

Q. Do your drilling reports confirm and verify the information that you just reviewed for the Examiners in the wellbore diagrams?

A. Yes.

Q. Will Chevron provide the Division a complete electronic copy of the drilling reports that they require or request?

A. Yes.

Q. Also within that Item Number (iv), the Division has requested a cement bond log for the wells. Has Chevron prepared a cement bond log for the two wells at issue?

A. A cement bond log is provided for SD EA 19 Federal P6 5H.

Q. Has that been marked as Exhibit 25?

A. Yes.

Q. Will you review for the Examiners what that exhibit shows?

A. Yes. This is a cement bond log for that specific well. It's the SD EA 19 Federal P6 5H, and what this shows is the amplitude --

Q. Let me get it up there for you, sorry.

A. Which is shown here in this column is amplitude, you will see right here and you will see it here as well. And this is what we are using in order to estimate the top of cement. What you will see here is casing. You will see the amplitude increases -- I'm sorry -- decreases.

Q. And the --

A. So --

Q. Sorry, go ahead.

A. So a higher amplitude indicates more free pipe, and if have you a lower amplitude that indicates resistance behind pipe, which is indicating there's cement behind pipe.

So based on this information, and based on the amplitude, the top of cement is at approximately 4128.

Q. If this Division requests, can Chevron or will Chevron provide a full digital copy of the cement bond log on their request?

A. Yes.

Q. As to the other well, will Chevron provide cement bond logs at the time it conducts regular well maintenance both the tubing if the Division requires you to run cement bond logs at that time?

A. Yes.

Q. Very good. Now, other than that, is everything else required by the Division -- is everything else that was requested by the Division in the items that have been presented, you provided that in your testimony; is that correct?

A. Yes.

Q. Very good. Now, moving on to Item (v), the question that the Division has asked is for Chevron to confirm whether casing burst pressure will be at least 120 percent of the maximum allowable surface pressure, plus the hydrostatic pressure from a full column of reservoir fluid for both wells. Is that addressed in Item Number (v)?

A. Yes.

Q. Looking at your next exhibit, Number 26, will you

review for the Examiners your calculations to confirm that the casing burst pressure is within the requirements that the Division set out?

A. Yes. This exhibit shows the casing burst pressure calculations that were utilized for the first well, which is Salado Draw 19 26 33 Federal Com 2H, we have the casing burst pressure rating at 12,640 psi.

For the calculation of the 120 percent maximum allowable surface pressure, that value is 1500 psi. We added the hydrostatic pressure of a column of reservoir fluid, and that's based on 9171. That's based on TVD times .49 psi per foot, and that is equivalent to 5,994 psi. So based on this value, the casing burst pressure rating is 211 percent higher.

For the next well, the Salado Draw EA Federal P6 5H, the casing burst pressure rating is the same as the previous well, which is 12,640 psi. For the calculation of the 120 percent MASP, that was 1500 psi, and we added the hydrostatic pressure of column of reservoir fluid, which is equivalent to 9196 TVD, times the reservoir fluid which is .49 psi per foot, and that is equal to 6006 psi. Therefore, based on that value, the casing burst pressure rating is 210 percent higher.

Q. Very good. So in your opinion, the conditions imposed by the Division here have been met by Chevron's pipe

standards for this well?

A. Yes.

Q. For both wells?

A. For both wells, yes.

Q. All right. Now, also on under Item (v) here, the Division has asked for the drilling reports and confirmations of drilling reports and cement bond logs reflecting cement coverages for the entire vertical length of the well.

Based on the drilling reports and calculated documents indicate the cement bond log for the one well, is it your opinion that cement for both of these wells meets the Division's requirements?

A. Yes.

Q. And now, is it your opinion also that a mechanical -- see if that's the right -- first thing. So moving on to the next item in the Division's list of items, Roman numeral (vi), they asked Chevron to perform an assessment of the surrounding wells within the half mile area of review. Have you conducted that assessment?

A. Yes.

Q. Let's look at what is marked as Exhibit Number 20 --

HEARING EXAMINER ORTH: Seven.

Q. -- 7 -- getting there. Thank you very much.

What's been marked as Exhibit 27 in your packet, will you please review for the Examiners what this shows?

A. Yes. This is the map showing the offset of the wells that are penetrating the injection interval within the one-half mile of the area of interest.

Q. So in each case for each well, you drew a half mile area around each of the wellbores, the completed laterals that are going to be the portion of the well injecting; is that correct?

A. Yes.

Q. But you didn't limit your area of review to the surface location or bottom hole location, but instead your area of review extends around the entire portion of the wells that will be injecting?

A. Yes.

Q. Okay. Now, you indicated that this map identifies each of the wells that fall within those areas of review and that are identified by the sticks and numbers; is that correct?

A. That is correct.

Q. And the second page of that exhibit, do you have a table containing all the prior information for each of those wells that fall within the area of review?

A. Yes.

Q. And the wells identified here are the wells that

are penetrating the injection interval, those are the wells identified in this table and within the area of review map?

A. Yes.

Q. Of these wells on this table, how many are not operated by Chevron?

A. Four.

Q. Four. So of all those wells that are operated by Chevron. Is it your opinion that these wells and their cement casing adequately meet the Division's requirements?

A. Yes.

Q. For protection against any kind of transmission or migration of fluids out of the injection zone?

A. Yes.

Q. Very good. Those four wells not operated by Chevron, did you review more carefully their construction by pulling the wellbore diagrams for each of those wells?

A. Yes.

Q. Are those marked as Exhibit 28 in your packet?

A. Yes.

Q. Based on your review of construction of each of those wells, is it your opinion that casing and cement for those wells meet the Division's requirements?

A. Yes.

Q. And is it your opinion, Mr. Acero, that for all the wells within the area of review, you have not identified

any wells that require remediation or could potentially provide a conduit for migration of fluids or injection of gas out of the injection interval?

A. That is correct.

Q. Very good. Now, as to the integrity of the wells that you are proposing to -- for injection, the Division also has asked that Chevron demonstrate that these wells can withstand certain pressure limits. Have you conducted a mechanical integrity test to confirm that?

A. Yes, we conducted a mechanical integrity test on both wells.

Q. Let me get up to this. So what has been marked Exhibit 29, will you review for the Examiners what the first page of this exhibit shows?

A. Yes. This is the chart for pressures when we conducted the MIT, we started at 1400 psi, and after approximately 30 minutes the last pressure was 1375.

It's a little hard to see but this is where we started, and this is kind of where we ended. But there's a little line that's kind of hard to see which shows the pressure.

Q. So you started at 1400 psi, and after how many minutes?

A. 30 minutes. After 30 minutes you see this little reddish line here, and this is where we --

Q. In your opinion, does that meet the -- demonstrate that this well is able to meet the minimum pressure under 110 percent maximum allowable surface pressure as required by the Division?

A. Yes.

Q. Did you do the same analysis for the second well?

A. That is correct.

Q. And is the second page of this exhibit the pressure recorder chart for that well as well?

A. It is the MIT where we started at 1400 psi, and at the end of 30 minutes the final pressure was 1360 psi.

Q. So this pressure recorded chart indicates that this well also meets the Division's requirement to be able to meet the 110 percent of the maximum allowable pressure required by the Division as well; is that correct?

A. That is correct.

Q. Great. Now, in addition to the integrity of these wells, is it your opinion -- well, let me get your conclusion. Is it your opinion that these two wells meet the mechanical and operational integrity requirements by the Division?

A. Yes.

Q. And you have no concerns these wells will be able to function injecting the gas at the rates proposed by Chevron?

A. That's correct.

Q. And in fact, these wells are currently being operated under gas lift, so they are operating as injection wells, but for short periods of time; is that correct?

A. That's correct.

Q. Okay. Now, looking at what's been marked as Exhibit 30, the Division has asked that Chevron prepare a gas analysis for the gas that's going to be injected?

A. Yes.

Q. That's what's marked as Exhibit 30. Will you review for the Examiners what that analysis shows?

A. Yes. This is the gas analysis composition. This is gas we will be utilizing to inject into the well. As you will notice, there is zero percent h2s, and 4 percent CO_2.

Q. And this gas that you are proposing to inject, this is the same gas that Chevron is currently injecting for purposes of it's gas lift operations?

A. Yes.

Q. These wells are equipped and Chevron is able to operate its gas lift with this gas currently?

A. Yes.

Q. And you have seen this -- Chevron has in place any plans or does it treat the wells chemically in any way to defend against any potential corrosion should that occur?

A. The gas is dehydrated. Not only is it dehydrated, but we also treat it with chemicals.

Q. And those chemicals are designed to prevent any kind of corrosion within the wells?

A. Correct. Yes.

Q. And in Item Number (ix) in Exhibit 7, the Division has asked that Chevron evaluate whether the maximum allowable surface pressure will be greater than 0.14 psi per foot to the topmost injection interval. Have you conducted that calculation to confirm whether that's going to be the case?

A. Yes. We conducted for both wells. And the maximum allowable surface pressure divided by the TVD is the equation we used. And based on the equation, the proposed maximum allowable surface pressure does not exceed .14.

Q. And are your calculations, are they identified in Exhibit 31?

A. Yes.

Q. So in either case, are you exceeding that indication that -- well, that -- that guideline that was provided by the Division on either of these wells?

A. Yes.

Q. Okay. Now, moving on to the other aspects of the Division's conditions and requirements, looking at Exhibit Number 7, under Item Number -- the Division has asked that Chevron provide information on you how plan to be monitoring

injection operations as well as safeguards. In this case, how is Chevron going to be monitoring its injection operations in these two wells?

A. Chevron currently has a SCADA system which is a centralized system which monitors, and it also controls the area. This allows the operators to change set points. It also allows them to set alarms. Therefore these set points are what's going to be in place in order to not exceed the MASP.

Q. Now, connected with that -- or related to that monitoring, does Chevron also have safeguards in place that will automatically shut down injection should those limits be reached?

A. Yes. There are automatic shut-down valves, and those are located at the compressor station, as well as at the wellhead for both of the wells.

Q. So in the event that the limits are reached, and those limits are 1250 psi; is that correct?

A. That's correct.

Q. And that's your surface, maximum surface injection pressure, if that limit is ever reached, then you have automatic shut-downs that will terminate injection either from the compressor or from the wellhead?

A. That's correct. At the compressor station, it is a bit higher, however at the wellhead it is at 1215. That's due to the pressure drop.

Q. Okay, very good. So, so there's a change in pressure from the pressure station down to the wellhead and that counts for that differential?

A. That's correct.

Q. Now, will Chevron also be reporting operations on these wells on C-115 reports monthly to the Division including injection volumes, pressures, and days in operation?

A. Yes.

Q. And as to corrective action, the Division has asked that Chevron either prepare or have in place a plan for -- a response plan in the event there are any issues that arise during operation and injection. Has Chevron prepared such a plan?

A. Yes, Chevron currently has an emergency action plan.

Q. And because of this operation or proposed pilot project, does Chevron have to update its plan, or is the plan already adequate to address all the issues that may arise?

A. The plan is currently adequate.

Q. And if requested by the Division, can you provide the Division a copy of that response plan?

A. Yes.

Q. Mr. Acero, in your opinion, will the granting of this application be in the interest of the prevention of waste and protection of correlative rights?

A. Yes.

Q. In your opinion will the operation of this pilot project, can it be operated safely in a manner to protect against risk to human health and the environment or impacts to fresh water sources?

A. Yes.

Q. Mr. Acero, were Exhibits -- let me get the numbers right because I have lost track of where we are. Were Exhibits 23 through 31 either prepared by you or under your direction and supervision?

A. Yes.

MR. RANKIN: At this time, Madam Examiner, I move the admission of 22 --

HEARING EXAMINER ORTH: 23.

MR. RANKIN: -- 23 to 31 into the record

HEARING EXAMINER ORTH: Exhibits 23 through 31 are admitted.

(Exhibits 23 through 31 admitted.)

MR. RANKIN: Thank you very much. At this time I pass the witness, and I have no further questions.

HEARING EXAMINER ORTH: Thank you. Mr. Coss, any questions?

EXAMINER COSS: Not very many. Thanks for putting everything together and following our letter so carefully. That makes preparing the order much easier, and I would say that submitting a full electronic CBL would be helpful, but I'm not -- we're not interested in the health and safety plan; is that correct?

EXAMINER McCLURE: I'm not.

MR. RANKIN: You might want to rephrase that.

EXAMINER McCLURE: Interested in having it given to us. Interested in knowing it exists.

EXAMINER COSS: Thanks for keeping me in line. And the only other question that I have, is the surface injection pressure, does Chevron think that's going to be adequate, more than adequate to accomplish the injection, or was -- did it feel somewhat hampered by the Division's request for the injection gradient?

THE WITNESS: Yes. As Dr. Tang mentioned, that would be adequate based on his research, based on his study.

EXAMINER COSS: Perfect. Thank you.

HEARING EXAMINER ORTH: Mr. McClure?

EXAMINER McCLURE: Yes, I guess, some of my previous questions, as far as the production in the area, about how many wells do you believe one of these injection wells can handle during down time?

THE WITNESS: That's the purpose of the pilot, we don't --

EXAMINER McCLURE: To determine it?

THE WITNESS: To determine it, that's correct.

EXAMINER McCLURE: Now, if we were to pursue that you end up with 2 million cubic feet per day over a period of two weeks, how many wells can two million cubic feet per day handle?

THE WITNESS: Currently if we were to inject 10,000 MCF, that would be sufficient to be able to continue producing almost half of the field.

EXAMINER McCLURE: So basically you would need five wells for half the field. Is that correct then?

THE WITNESS: If the rate is 2000, yes.

EXAMINER McCLURE: Okay, I'm with you. I'm with you. And obviously we'll know more a year from now. It looks like your schedule had you out for ten months, I believe. Is one year going to be adequate then you believe?

THE WITNESS: We believe so, yes.

EXAMINER McCLURE: Okay. Now, what is, at 1000 surface pressure, your injection gas, what is a good estimate for pounds per foot as far as density for that column of gas? Do you think like .1 pound per foot, in that line, like 14?

THE WITNESS: This might be a scope for Dr. Tang.

EXAMINER McCLURE: I apologize. I'll withdraw that question. It's neither here nor there. We'll look at it after we see your finished report. I'm sure it will be included in there, so I will withdraw that question for now.

The MIT that you -- or, excuse me -- the CBL that you ran, is that a recent CBL and not the original one from when the well was first put into production?

THE WITNESS: The CBL?

EXAMINER McCLURE: The one included for 5H.

THE WITNESS: The original CBL.

EXAMINER McCLURE: Now, I think we have one on record for the 2H as well. Do you not have that CBL? I notice it's not included in here.

HEARING EXAMINER ORTH: I thought it was the second page.

EXAMINER McCLURE: The CBL?

MR. RANKIN: It's just the one in the exhibit packet. Does it have the second one available on line?

EXAMINER McCLURE: Yes, I believe so. I was just confirming I guess what Chevron --

THE WITNESS: 5H, that is the CBL we currently have.

EXAMINER McCLURE: But you also have one for the 2H?

THE WITNESS: For 2H it was based on calculations.

EXAMINER McCLURE: Okay. For some reason I was thinking in our well files that the Division had one on record for it, and I believe that the estimated top of cement on that one was actually --

THE WITNESS: 3830.

EXAMINER McCLURE: Yeah, and I believe when you look at the CBL for it, it was actually -- when you -- into the good cement, it's significantly lower, but I believe it's still within the immediate casing. We will probably look into that a little bit more prior to actually writing any sort of recommendation for this. But I was just seeing, I guess, whether you were familiar with what we are talking about, but we will look into it a little bit later then.

The CBL that we have here, we don't know whether there was pressure held on the casing then since that was taken. Or was it taken under zero pressure? I don't believe it says on there. I don't remember what exhibit it was now.

THE WITNESS: I would have to come back.

EXAMINER McCLURE: 25, it looks like.

THE WITNESS: At this point I don't know.

EXAMINER McCLURE: Okay. I apologize. I'll withdraw that question.

As far as the economic limit on these wells in this field -- excuse me. As far as the economic limit on the wells in this field, what is the economic limit for oil production for this well. Are we about reached to it, or what are we looking at as far as that goes?

MR. RANKIN: You can answer. If you don't know, then don't speculate. But if you know the answer --

EXAMINER McCLURE: If you don't know the answer to that, that's fine. I guess let me rephrase it. Do you believe you are likely towards the later end of this well's economic limit life, and if you know it, otherwise not.

THE WITNESS: I don't know.

EXAMINER McCLURE: I apologize. I will withdraw that question. When the MIT was conducted, what was your fluid column made up of?

THE WITNESS: It doesn't say, but I can get to that question at a later time.

EXAMINER McCLURE: Okay. Thank you. We will get you to submit that at a later point then. Okay. Now, there may be a mistake in the records, I don't have it in front of me, but one of these wells, I believe we had 17-pound casing in it instead of 20-pound casing.

It's not going to make a significant difference, but just for the record we may want to just correct it so we have the correct percentage of safety factor. I believe it was 10,000 pounds and went to 12,000 pounds burst pressure, so it's not a big deal at all. We may just want to see the corrected value so we have a correct one in the record.

I could be mistaken, I'm only looking at what we had on record here, so that could be mistaken on the record as well, and it may be 20 pounds for both wells. We may just want to look into that a little further, I guess.

MR. RANKIN: We will double check and get back to you.

EXAMINER McCLURE: Okay, thank you. I don't remember if it was the 2H or 5H, off the top of my head. I just noticed that one had 17 and one had 20, but I didn't think it was too awful concerning because one is 12,000 and one is 10,000, which is significantly more anyway, but --

And then I guess, just to confirm, you've already answered this question, but just to confirm, you believe then that with your dehydration and the addition of chemicals, you do not believe that you have any degrading of the casing due to the injection gas?

THE WITNESS: It would be low risk.

EXAMINER McCLURE: Low risk of it. Okay, thank you.

I actually believe that's all my questions. Thank you.

HEARING EXAMINER ORTH: Thank you.

Mr. Rankin, anything further?

MR. RANKIN: One issue.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Acero, both of these wells are currently being utilized for gas injection; is that correct?

A. That's correct.

Q. And the same gas is being injected for that purpose?

A. Yes.

Q. How long have these wells operated under gas lift with this gas, this composition, approximately?

A. Close to four years.

Q. In that time you haven't identified any issues with your -- with corrosion based on your well maintenance and the way you're operating these wells?

A. Not currently.

MR. RANKIN: Thank you. Nothing further.

HEARING EXAMINER ORTH: All right. If there is nothing further, thank you very much, Mr. Acero.

HEARING EXAMINER ORTH: Mr. Rankin, I understand you had a fourth witness.

MR. RANKIN: Snowed out, and if I didn't make the statement already, I apologize. Madam Examiner, at this time we would ask that the case be continued to the March 19 docket so that we may present the full land testimony regarding the notice and the status of the notice.

HEARING EXAMINER ORTH: All right.

MR. RANKIN: We request that we do that by affidavit first. We will assume that there will not be any objection to that at the time.

HEARING EXAMINER ORTH: All right. Thank you. I'm not sure whether, because we are already part way into the hearing or most of the way into the hearing whether that would need to be done through the portal or not. Do you think so?

MR. RANKIN: Yes.

HEARING EXAMINER ORTH: Go ahead and do that to March 19.

MR. RANKIN: We will file a motion requesting a continuance and the grounds for it and the filing fee as well.

HEARING EXAMINER ORTH: Thank you very much. I saw a gentleman over here standing up. Sir?

MR. SINGER: Madam Hearing Examiner, I was wondering if you would entertain a quick public comment.

HEARING EXAMINER ORTH: Oh, yes. Thank you, Mr. Rankin. Please tell us your name, and I will need to swear you in if you are going to make a statement.

Do you swear or affirm that the statement you are about to give will be the truth, the whole truth, and nothing but the truth.

MR. SINGER: Yes, I do.

HEARING EXAMINER ORTH: Tell me your name and spell it.

MR. SINGER: It's Thomas Singer, S-i-n-g-e-r.

HEARING EXAMINER ORTH: Okay.

MR. SINGER: I'm the senior policy advisor with the Western Environmental Law Center.

HEARING EXAMINER ORTH: Okay.

MR. SINGER: I'm not an attorney, so I didn't enter an appearance. I'm a member of the governor's methane advisory panel, and we have been -- had long concern for methane waste in gas production. I just would like to offer support for this project. And we think, given appropriate environmental protections as discussed by the witnesses, this project is in the public interest and we encourage the director to approve it.

HEARING EXAMINER ORTH: Oh, well, thank you very much, Mr. Singer. Do the other Examiners have any questions of Mr. Singer?

EXAMINER McCLURE: No questions here.

EXAMINER COSS: No questions.

HEARING EXAMINER ORTH: Mr. Rankin, did you have any questions?

MR. RANKIN: No questions. I appreciate Mr. Singer's appearance and support for the project.

HEARING EXAMINER ORTH: Oh, thank you. Is there anything else?

MR. RANKIN: Nothing further. We appreciate the opportunity to appear with our land testimony on March 19.

HEARING EXAMINER ORTH: All right. Thank you very much.

(Case continued.)

STATE OF NEW MEXICO)
)SS
COUNTY OF SANTA FE)

I, IRENE DELGADO, certify that I reported the proceedings in the above-transcribed pages, that pages numbered 1 through 82 are a true and correct transcript of my stenographic notes and were reduced to typewritten transcript through Computer-Aided Transcription, and that on the date I reported these proceedings I was a New Mexico Certified Court Reporter.

Dated at Santa Fe, New Mexico, this 6th day of February 2020.

____

Irene Delgado, NMCCR 253
Expires: 12-31-20