STATE OF NEW MEXICO

ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

Application of OXY USA Inc. for
a Closed Loop Gas Capture Injection
Pilot Project in Eddy County, New Mexico CASE NO. 22150

Application of OXY USA Inc. for
a Closed Loop Gas Capture Injection
Pilot Project in Eddy County, New Mexico CASE NO. 22151

Application of OXY USA Inc. for
a Closed Loop Gas Capture Injection
Pilot Project in Eddy County, New Mexico CASE NO. 22152

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

THURSDAY, SEPTEMBER 9 AND 10, 2021

SANTA FE, NEW MEXICO

This matter came on for hearing before the New Mexico Oil Conservation Division, William Brancard, Hearing Examiner, Dean McClure, and Dylan Rose-Coss, Technical Examiners, on Thursday, September 9, 2021, via the Webex Teleconferencing platform hosted by the New Mexico Energy, Minerals and Natural Resources Department.

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C O N T E N T S

CASE 22152

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CASE NO. 22150

(Time noted 11:10 a.m.)

EXAMINER BRANCARD: Okay. With that I would like to call Case 22150, OXY USA.

MR. RANKIN: Mr. Examiner, Adam Rankin and Kaitlyn Luck with the law firm of Holland and Hart in Santa Fe appearing on behalf of the applicant in this case.

EXAMINER BRANCARD: All right.

Mr. Rankin, are you proceeding with each of those cases separately?

MR. RANKIN: Mr. Examiner, we would request that we present these cases slightly out of order from what has been proposed by the Division, and that we consolidate these cases for purposes of hearing but each would be issued a separate Order.

EXAMINER BRANCARD: Okay. So you would like to consolidate 22150, 22151, 22152?

MR. RANKIN: Yes, Mr. Hearing Examiner, and we would ask that we be permitted to present Case No. 22152 first, and as we did at the last hearing, we are actually presenting these closed loop gas injection cases -- we intend to present the first case with a little more detail and then simply summarize the key operational differences for the other two cases.

EXAMINER BRANCARD: All right. I believe that's

okay.

I believe we have an Entry of Appearance for MRC Permian in 22150.

MR. BRUCE: Yes, Mr. Examiner. Jim Bruce representing MRC Permian. I don't have any objections to proceeding by affidavit or consolidating the cases, and I will not be asking any questions.

EXAMINER BRANCARD: All right. Thank you. Is that correct you're just in 22150?

MR. BRUCE: That's correct.

EXAMINER BRANCARD: Thank you.

Are there any other entries of appearance for Cases 22150, 22151, 22152? (Note: Pause.)

Hearing none, Mr. Rankin please proceed in whatever order makes sense with these three cases.

MR. RANKIN: Thank you, Mr. Examiner.

In these three cases we will be starting with Case No. 22152. We have three witnesses to present, and if it pleases the hearing examiner, perhaps we can go ahead and get these three witnesses sworn in at this time.

EXAMINER BRANCARD: Okay. Who are the names a your witnesses?

MR. RANKIN: Mr. Examiner, we have Mr. Stephen Janacek, Mr. Tony Troutman, and Ms. Xueying Xie.

EXAMINER BRANCARD: You struggled with that last time, Mr. Rankin. I thought by now you'd have it down.

MR. RANKIN: I don't have confidence in myself. That's my problem.

EXAMINER BRANCARD: Okay. So will those three witnesses raise their right hands.

(Whereupon Stephen Janacek, Tony Troutman and Xueying Xie were duly sworn by Examiner Brancard.)

EXAMINER BRANCARD: Okay. Thank you.

All right. Excellent. Mr. Rankin, please proceed.

MR. RANKIN: Thank you, Mr. Examiner.

I would like to call OXY's first witness, Mr. Janacek.

STEPHEN JANACEK,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

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

A. Yes. Stephen Janacek.

Q. Will you please spell your name for the benefit of the court reporter.

A. Sure. My first name is spelled S-t-e-p-h-e-n, last name J-a-n-a-c-e-k.

Q. By whom are you employed?

A. I am employed by OXY.

Q. In what capacity?

A. As a petroleum engineer.

Q. Have you previously testified before the Division?

A. Yes.

Q. And you're familiar with the application filed in this case and the other two cases?

A. Yes, I am.

Q. Have you undertaken an engineering study following the Division's Closed Loop Gas Capture Guidelines?

A. Yes.

Q. Did you also oversee and coordinate OXY's land department's identification of all the affected parties required to be notified under the Division's guidelines?

A. I did.

MR. RANKIN: Mr. Examiner, at this time I would retender Mr. Janacek as an expert witness in petroleum engineering.

EXAMINER BRANCARD: So approved.

Q. Mr. Janacek, did you prefile Written Testimony in this case?

A. Yes, I did.

Q. Do you adopt that testimony today as your sworn testimony for today?

A. I do.

Q. And is that Prefiled Written Testimony marked as Exhibit B in this case?

A. Yes, it is.

Q. Did you also prepare additional exhibits marked as Exhibits B-1 through B-6?

A. Yes.

Q. And were the materials and exhibits you prepared in support that are covered in your testimony part of what is required to be addressed by the Division's guidelines for closed loop gas capture projects in terms of the geology and reservoir engineering topics?

A. Yes.

Q. And those materials that you prepared and were covered in your testimony are in Exhibit A from pages 3 through 75 and 96 through 99?

A. They are.

Q. And OXY in this case, in all three cases, is seeking Division approval for closed loop gas capture injection projects; is that correct?

A. That's correct.

Q. And the purpose is to temporarily inject gas through certain of its horizontal wells, production wells

that would otherwise be flared during a downstream upset or interruption or require OXY to shut in its affected wells?

A. That's correct.

Q. Now, in this case the project area that you're proposing would be approximately 1,120 acres, more or less, is that right?

A. That is correct.

Q. That would be located in the west half/west half and east half of Sections 17 and 18 in Township 24 South, Range 31 East in Eddy County?

A. That's correct.

Q. And the project area on the proposed injection wells will be targeting the Bone Springs Formation?

A. Yes.

MR. RANKIN: I'm going to share, if I might with, uhm -- my screen, Ms. Salvidrez. May I have permission?

Thank you.

Q. Mr. Janacek, let me know when you're able to see my screen.

A. I can see it now.

Q. Great. What has been marked as page 8 in Exhibit A that was filed on Tuesday, do you see that?

A. Yes, I do see that.

Q. This is page 8 of that exhibit. Will you review -- in referring to the exhibit, uhm, giving a review of the projects, and if you would explain -- actually I'm going to skip down one page.

Uh, this is a -- would you review with the examiners what this project area shows the examiners of the proposed project area?

A. Sure. So on this page here, page 7, we're looking at a map of the project area. This is the South Corridor area also known as the Patton area.

We're showing a couple of things here, the first of which is the blue dashed project outline, which is the project area that corresponds with all of the wells' horizontal spacing units.

Then the next element we're looking at is the black wellbore trajectories.

So since these are all horizontal wells that we are proposing as CLGC injectors, we have our surface hole locations, we have our first take points as notated with FTP, and then we have the last take point, notated with LTP.

So we have each of the wells, and then there are some other facility elements that we've included, as well. It's a little hectic here but I'll walk through just the colors and what they represent.

So if we start at one of the surface hole locations of the black wellbore trajectories, we then have a green flow line which is flowing from the wellhead to the central tank battery here. The central tank battery that flows through is the pink Sand Dunes South Corridor CTB in the middle of -- center of the page there.

From there the next element we have is the red low-pressure pipeline which flows from the central tank battery to multiple points, one of them being, uh, the blue star and one of the gas takeaways, and then the other leading to the east and west CGL or Compressor Gas Lift stations. Those are notated with the black squares.

Then the east and west CGLs are linked to the orange high-pressure gas lift line which then travels back to the gas lift wellheads themselves.

Q. Then in this particular application OXY is proposing to inject for temporary storage to two different intervals within the Bone Spring Formation; is that correct?

A. That's correct.

Q. And the project will include 11 producing wells that would temporarily be converted to injection during downstream upsets?

A. Yes.

Q. And the total injection intervals will range

from between about 8,828 feet to about 10,283 feet total -- true vertical depth; is that correct?

A. Yes.

Q. Now looking at the next page of your Exhibit A, just review for the examiners, if you would, briefly, the normal operations during gas lift and then how OXY proposes to operate these facilities during interruptions when gas would be temporarily stored through injection through these wells.

A. Sure. So this is a process flow diagram of the facility that we just viewed. All of the elements and the colors are the same across both (inaudible) reference. This is just a lot cleaner and easier to read.

So again we'll start at the wellheads here. We have the 11 CLGC wells in the bottom-right-hand corner of the slide, and during normal operations the produced fluids will come out of the wellhead, travel down the green flow line to the Sand Dune CTB, the central tank battery. There are other wells in the system that are included in the source wells later on in this application, and those wells also flow to the central tank battery. At the central tank battery the fluids are separated and the oil is sold, the water is sent to water disposal wells, and the gas enters the red low-pressure gas pipeline system.

Once the gas enters the red pipeline system, it has a couple of pathways it can take. The first pathway it can take is to the primary gas takeaway, which is Enterprise, and the second company is Lucid. That is where we predominantly sell our gas in this system.

The next pathway the gas can take is to the red star indicating the flare, and then the last pathway the gas can take is to the east and west CGL stations.

Once the gas passes through the CGL stations the gas is pressured up to approximately 1250 psi and then it enters the orange high-pressure gas lift pipeline. From here there's two options or two pathways that the gas can take. The first is to the DCP secondary gas takeaway, which is regularly used. It is only used whenever we have periods of upsets and it can only handle a fraction of our total gas produced in the system.

The next pathway the gas can flow through is back to the gas lift wells themselves, and once it flows back to the gas lift wells themselves that completes the circuit as outlined here on the diagram.

So that's how normal operations work.

The overall operations we are able to remove our fluid streams from the systems by selling the oil, by disposing of the water, and selling the gas.

However, if there is a third-party interruption that occurs at our gas sales point, we're seeking the authority to utilize these eleven wells as gas storage wells.

And you're kind of in -- there's a couple of different things that occur. The first that triggers everything is the third-party gas sales, here being Enterprise or Lucid, they encounter some type of event that we are unable to sell gas to them. So at that point in time the valve leading to that sales point is closed.

Once this occurs and we are still producing wells, we'll start to see a build-up of gas in the low-pressure gas pipeline system. That's because we can only sell so much gas to the secondary DCP takeaway, and we are unable to remove gas from the system otherwise, so in order to continue operations and continue oil and gas production from the other wells, the other source wells in the network, we utilize the 11 proposed CLGC wells as storage wells.

So in the CLGC storage event, the CLGC will shut in at the safety shutdown valve at the wellheads, so produced fluids will no longer come out of these wells. However -- but, however, we will still have injected gas going into these wells and therefore utilizing them as storage wells.

So that's a breakdown of the normal

operations and then a storage event. And then finally, once a storage event ends we will open up the shutdown valves on the CLGC storage wells and return them back to normal production.

Q. Thank you. And in this case, these three cases, is OXY requesting authority to inject under this project for a term of two years?

A. Yes.

Q. And does OXY also seek the ability to administratively add injection wells to the project within the Area of Review?

A. Yes, we do.

Q. Does it also seek to administratively extend authority to inject without the need for a further hearing?

A. Yes.

Q. Does the information and data for each of the injection project wells that you identify here, including well-diagram information and well construction included in your Exhibit A?

A. Yes.

Q. Do all the wells have a packer in the hole in this case?

A. Yes, all of these wells have packers in the hole.

Q. Does OXY request authorization from OCD to place packers as deep as possible but no more than 100 feet above the top of Bone Spring Formation?

A. That's correct.

Q. Has OXY provided a copy of all of the CBLs for each of the project wells to the Division?

A. Yes, we have.

Q. Looking at -- I'm going to skip ahead here to page 43 of Exhibit A. Right there.

Will you just review what this shows an explain what the current average surface pressures are under normal operations during production for the project wells?

A. Sure. Could you zoom in a little bit more on that?

Q. I can do that. No sense in straining your eyes. Let me know if you are able to see.

A. Yes, I can see that a lot better. I'm sure the examiners can, as well.

So this is a chart indicating each of the 11 CLGC wells and various items.

We have the proposed Maximum Allowable Surface Pressure on here, we have the Current Average Surface Pressure under gas lift operations. We also have a Maximum Achievable Surface Pressure with our current

infrastructure, which is 1250 psi.

I would also like to note that we aren't adding on any additional infrastructure to increase our maximum allowable pressure than what we already have out in the field.

We are also showing here the proposed average injection rate, which is 1.8 million standard cubic feet per day for each well. We also have proposed max injection rate, which we estimated to be about 2 million standard cubic feet per day.

Then the rest of the chart is the calculations that pertain to requirements as outlined in the CLGC guidance document. Those relate to Burst calculations, some Hydrostatic calculations, some Gas Gridding calculations, and also some Formation Parting Pressure calculations.

I'd like to note, instead of going through the details of this, that all of these wells in the calculations adhere to the CLGC Guidance documents.

Q. Thank you very much.

Will OXY monitor its injection and operational parameters with an automated SCADA system?

A. Yes, they will.

Q. And will there be pre-set alarms and automatic shut-in (inaudible) valves that will prevent the wells

from exceeding the 1250 MASP?

A. Yes.

Q. Now, let me zoom back in here so I can see what we're on.

Looking at the next page of your Exhibit A, will you just give a brief overview of the well set-up for the wells in this project and explain how they will operate during normal production and then during injection operation?

A. Sure. So I -- what was stated previously, all of these wells will be tubing flow and casing injection wells with a packer currently in the hole.

So I'll walk through this diagram for the flow-through during normal operations, and then we'll talk about a gas storage event and how operations change slightly.

So if we start with the left-hand side of the screen we have our injection stream of produced gas coming back to the wellhead. The produced gas that's being utilized for injection purposes will be flowing through a flowmeter which records and shares the rate of injection with our SCADA system. Then the injected gas will flow through the control valve which also is linked to our SCADA system and controls the injection rate and the injection pressure.

Next, as we get closer to the well we pass through the casing head and the SSV or the Safety Shutdown Valve on the casing side. This is also connected to our system, our SCADA system, where we are able to remotely open and close that valve.

On the opposite side of the casing head, we have some pressure recording devices. There's the PIT, the Pressure Indicating Transmitter, and the PI, the Pressure Indicator. These are also linked to your SCADA system where we are able to record the casing pressure on this well.

So once the fluid flows through the wellhead on the injection side of things, it will flow down the casing tubing annulus, through the gas lift mandible's downhole, and then be produced back with the produced fluids.

The produced fluids will come back up through the wellhead and back up to the upper portion of the wellhead, which is called the tubing head. Here we have some of the same elements on the tubing side as we do the casing side.

So there is a pressure indicating transmitter, there is a safety shutdown valve that can be utilized to open and close the production side of the well, and then we have a flow control valve which controls

the rate and pressure before the produced fluids enter the flowline.

Once the fluids enter the flow line they proceed on to the central tank battery, which is not indicated on this diagram.

So that is the makeup and the flow of fluids through the wellhead during normal gas lift operations.

So now talking about the gas storage operations, we'll keep the same wellhead, the same equipment on locations, and the fluid will still enter -- uh, the injection stream will still enter from the left-hand side and pass through the system. The main difference here is we will be closing the safety shutdown valve on the tubing side, or the producing side, of the well.

So that is the SSV on the upper portion of the diagram. That will be closed, allowing us to no longer produce from this well and only inject fluids and store them for intermittent periods of time.

So this will close, this valve will close whenever we initiate a storage event, the gas will be stored downhole in the well, and then once the event has ended we will open up the safety shutdown valve and produce -- and begin to produce the well back.

So that's an overview of the current gas lift operations and then what operations would look like during a gas storage event.

Q. During injection what would be OXY's proposed average injection rate for -- during injection?

A. For these wells I believe our average rate is 1.5 million standard cubic feet per day.

Q. I'll just back up to that chart so you can...

A. Yes. Thank you for that. A correction there. It's 1.8 million standard cubic feet per day.

Q. And the maximum injection rate?

A. The maximum rate will be 2 million standard cubic feet per day, approximately.

Q. Have these wells previously been subjected to mechanical integrity tests, but not in the last year?

A. Yes, they have.

Q. Will OXY submit proof to the OCD that each well has passed pressure tests demonstrating mechanical integrity prior to commencing injection?

A. Yes, we will.

Q. Is the source gas going to be from OXY's Bone Spring and Wolfcamp wells that are identified within Exhibit A?

A. Yes.

Q. And all these potential source wells and

injection wells are subject to a commingling permitting approval from the Division?

A. That's correct.

Q. That's PLC 749?

A. Yes.

Q. Did OXY prepare analysis of the gas composition of the injection gas and the (inaudible) gas?

A. Yes, we did.

Q. Is that included in the exhibit?

A. Yes.

Q. Any compatibility issues?

A. There are no compatibility issues.

Q. Does OXY also have a current Corrosion Prevention Plan that's in place for these wells?

A. Yes, we currently have a Corrosion Prevention Plan in place for these wells.

Q. Will that plan be continued and applied during the proposed injection?

A. Absolutely.

Q. And that plan is included in your written exhibits, Exhibit A?

A. Yes.

Q. Now, does OXY also have an updated proposal for its data collection during injection operations?

A. Yes, we do.

Q. Is that attached as Exhibit B-1 to your affidavit?

A. Yes, it is.

Q. Mr. Janacek, will you just review for the examiners -- since this is updated since OXY last presented the closed loop injection case, would you review for the examiners what your Data Collection Plan is.

A. Sure thing. So here we have a Revised Data Collection Plan since we last spoke. Starting from the beginning, we had included a Revised Data Collection Plan, after reviewing the recently issued EOG Order and the data collection requirements found in said Order.

EOG, with their project they have the ability to test continuously all of their CLGC wells and the offset involved wells. In our case, in OXY's case we do not have the ability to test continuously based off of our current facility structure. OXY has commingling permits with multiple wells going to one tester, instead of having dedicated testers for each well.

EXAMINER BRANCARD: Is somebody asking a question?

MR. RANKIN: We have somebody may not be on mute.

(Note: The reporter read the record.)

THE WITNESS: I think you caught it all. I'm just looking at my notes here.

A. (Continued) Yes, I'll just go back through that and start my train of thought, rewinding about one minute or so.

Okay. So compared to EOG, OXY does not have the ability to continuously test all of your CLGC wells and the involved offset wells that we've identified in the proposed Data Collection Plan, and the reason why is because we currently have commingling permits in place, gas and oil commingling permits in this area where we have multiple wells going to one tester.

So the verbiage changes that we proposed here in this Data Collection Plan indicate that OXY will do our best to capture the data at the specific frequency as identified in the EOG Order; however, due to the equipment constraints on location we may not be able to do so always.

So that's the main takeaway of our proposed Data Collection Plan here. (Note: Pause.)

(Note: Reporter inquiry.)

MR. RANKIN: In fact I was muted, and I was trying to be helpful.

Q. Is Exhibit B-2 attached to your affidavit a graphical representation of the wells that OXY has

included in its proposed Data Collection Plan?

A. Yes, that's correct.

Q. Now, has OXY also developed an Updated Proposed Gas Allocation Method to allocate gas between what was injected and what has been ultimately produced?

A. Yes, we have.

Q. And that's in your Exhibit B-4 attached to your affidavit; is that correct?

A. That's correct.

Q. Will you just review for the examiners what OXY has done to update its proposed allocation method.

A. Sure. So here we have a new GOR Gas Allocation Plan which differs from the Gas Allocation Plan that was presented with the previous cases. In this allocation plan we reviewed the EOG gas allocation method and applied a similar approach.

So here we are utilizing the GOR or the gas/oil ratio in our oil tests to determine the ratio split and the return of storage gas versus the native gas production after we have a storage event.

So this method here will be applied on a well-by-well basis, and in this exhibit here we've attached an example of a one-day simulated storage event, and we have all of the corresponding columns and calculations that go along with the example.

So in addition to this new GOR gas allocation methodology, we've also included our tapered testing methodology, which we will cover in the next exhibit.

So I'm not going to walk through the details of each column in the row here, but one thing is to note, and that is the highlighted values that we see in three of the columns. So those highlighted values correspond with the well test which we will obtain for each of the CLGC wells to determine their GOR gas allocation calculation.

So what we've applied here is a tapered testing technique where we are able to obtain higher frequency well tests right after a storage event, and then over time will reduce the frequency or taper the frequency, reducing the requirements of our well testers.

This gives us the ability to require -- I'm sorry. This gives us the ability to capture data where it is important right after a storage event, yet it also gives us the flexibility operationally to balance our well-testing requirements for the commingling permits we have in place.

Q. And these well testing methods were adopted essentially from the commingling approvals that the Division has issued; is that correct?

A. Yes, that's correct. We reviewed the commingling verbiage that had been issued previously by the Division, and that's what we have described here in detail in the following exhibit.

Q. And that description describing your well-testing method is included in Exhibit B-5 attached to your affidavit?

A. Yes, that's correct.

Q. Now, did you also conduct an engineering analysis on all the wells within the half-mile Area of Review of the proposed injection project?

A. Yes, I did.

Q. Are the maps and data supporting that analysis included in your Exhibit A?

A. Yes, they are.

Q. In addition did you also prepare an updated Area of Review map that shows the actual well trajectory in Exhibit B-3?

A. Yes.

Q. And in your Area of Review analysis did you identify all the wells that penetrate the injection intervals in this case?

A. Yes.

Q. And do you include all the wells that are plugged in and actually penetrate the injection intervals?

A. Yes.

Q. Do you include the wellbore schematics for those wells that are plugged or abandoned?

A. Yes, those are included, as well.

Q. Did you identify any wells that would potentially serve as a conduit for injected gas to escape the injection intervals?

A. Excuse me. Yes. No wells were identified as conduits.

Q. Also, did you work with OXY's land department to identify the surface owners and all affected parties within the half mile Area of Review that's identified in your Exhibit B-3 through our, uh, requirement of identification in the Division's guidelines?

A. Yes, I did.

Q. Did you provide that with the parties to Holland and Hart?

A. Yes.

Q. Is Exhibit B-6 a true and correct copy of the affidavit prepared by our office reflecting that we provided Notice to each of those parties you've identified to us by Certified Mail?

A. Yes.

Q. Did we also prepare a Notice of Publication, and is that Affidavit of Publication included in the exhibit?

A. Yes, it's included, as well.

Q. With that, Mr. Examiner, I would move the admission of Exhibits A, B, and B-1 through B-6 into the record.

EXAMINER BRANCARD: Are there any objections? Hearing none, so admitted.

MR. RANKIN: Thank you, Mr. Examiner.

With that I would pass the witness for questioning by the examiners.

EXAMINER BRANCARD: Thank you.

So we have with us today special examiners for this hearing. We have Mr. Dean McClure and Mr. Dylan Rose-Coss.

Mr. McClure, who wants to go first?

EXAMINER McCLURE: It's up to Dylan if he wants to go first; otherwise, I will.

EXAMINER ROSE-COSS: Go for it, Dean.

EXAMINER McCLURE: All right.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. I guess a question I have is it seems like maybe this is a subset of the wells that's included in surface Commingling Permit PLC 749. Is that kind of correct?

A. Yes. This is a subset.

Q. So then essentially just prior to marketing and

title transfer, all 268 wells in PLC 749 is being commingled, but those additional wells is not included here, are not source wells for these gas lift operations. Is that correct?

A. That's correct.

Q. Okay. I'm just making sure I was having a clear understanding. That was my speculation or assumption, but I guess I was just confirming that.

Another question I had: On your tree diagram, you currently have where you have your annulus -- your production casing annulus, excuse me, having its pressure monitored. Is the intention to also install a -- some sort of pressure monitoring system for the intermediate casing, as well, and the surface casing?

A. Yes. Yes, that's our plan. That's outlined in our operational plan. I believe it's stated in there, Mr. Examiner.

Q. Yeah. I was assuming that was your plan, I guess, but I was just confirming.

Now, you have stated that there's currently tubing packers in the holes for these wells. Approximately do you know where they are kind of set at?

A. Yes. Their setting depths are reflected in the wellbore diagrams that were submitted with this application.

Q. Okay. Now just, I guess, as an overall view of a -- with -- are they essentially based on being around like, say, a 30-degree inclination, or what is the basis of where they are set?

A. They are set as deep as possible, as close to that 30-degree inclination, but some of them are not set that deep.

Q. Okay. Okay. I just was wondering what the thought process was, because I hadn't individually gone through them quite yet, what we are looking at.

I guess would it be accurate to say, though, that the ones that's in the Bone Spring 2 is below the top -- is probably even below the top of the Bone Spring 1? Is that correct, where the tubing packers are set?

A. I would have to review those individually to double check that. I do know that all of them are -- all of these wells have packers that are set beneath the top of the Bone Spring Formation.

Q. Yeah, I'll have to review them individually myself. I just hadn't quite done that yet.

I was going to say I don't have nearly as many questions as I did the last time. For the most part they are very similar in regards to the last cases that were submitted.

I guess if I can direct your attention, I guess, to I think it's Slide 74 for this particular case.

A. Okay.

Q. It's your AOR map where you have it listed out in your spread sheet on the follow page, you have it all identified there.

A. 74. Give me one second.

Q. Yes, sir.

A. Yes, I have it in front of me now.

Q. Okay. I guess my question to you is: I know in one of the earlier AOR maps, like there's a couple -- well, I guess just one slide above it -- you have all the laterals marked out for all the AOR wells, but on this map you do not.

I guess is there a reason that you didn't include it, and how onerous would it be for you to amend this to include those?

A. Good question. So since it wasn't -- since that map with the well trajectories was not included in the original submission here, what we have done is we included it as an exhibit, and I believe that exhibit number is B...

MR. RANKIN: B-3.

A. B-3? Yes.

So Exhibit B-3 has the well trajectories

included with an AOR map.

Q. Do you know what slide that's on? Oh, I think maybe, uhm...

A. I believe it is -- if we're at -- I believe it's 129 out of 153.

Q. I guess what my concern here is, is just a matter of easily being able to reference your Excel spreadsheet for the identification of which wells are included there. Do you have a numbering system you numbered there? Like, do you have up through, like, 77 or whatever the number is?

And that's not included in any of these. An easy way to correlate between the two without going back to the API number was the main thing I was looking at.

And I wasn't sure there was a reason that was left off of there or what the thought process was on the one that also has the numbers listed.

A. We could definitely add the numbers to this map that shows the trajectories. It was just a matter of, uh -- of producing double work here. But if that is something you-all would like to see, we can definitely put that together for you.

Q. Yeah, I was going to say maybe have a version like this and a version that instead of the API numbers

you actually just have the numbers listed like that. It's a little bit easier, I think, to identify than it is with the API numbers, because they take up so much area, might be the way to say it.

A. Sure.

Q. Just for your own reference, this here was what I was also kind of looking for in the prior three cases, as well. I think there might have been some misunderstanding, I guess, of what I was asking to be submitted, I guess.

A. Yes. That makes sense now that you say as we walk through it. So we can definitely provide that.

Q. Sounds good. Sounds good.

I was looking to see if there was any additional questions, I guess, that I have that we really didn't cover, I mean literally a month ago now, I think, for the previous three cases like this.

Is there anything, I guess, that stands out to you as being different in this case than those prior three cases?

A. Uhm, in this one we've already touched and highlighted in each of the discussions, the only thing else to note is here again we don't have any -- all of these wells have packers in the hole, so it makes things a little bit more simple for discussion.

Q. Yeah. It certainly does. I was going to say -- I mean, the only other new request, I don't think you had asked for before, maybe I'm incorrect on that, was this ability to add additional wells. But you might have asked for that last time, too, I just don't specifically recall.

A. No, you are correct. That was a new request that we included in this set of cases.

So what we would like the ability to do is if the well falls within the AOR that was previously conducted, we would like the ability to add on, uh, storage wells administratively.

Q. We'll have to discuss that on the Division side. I was going to say currently, uh -- currently we have not given approval for such, I mean on my prior cases. And I know there has been discussion related to that, and I don't know if we are quite prepared to start issuing such approval at this time, but it will be a discussion we will have to have.

But I don't think I have any questions related to it for this particular setting. So actually I think we might be a lot faster than we were the last time, because I don't believe I have any other questions for you related to this case.

So I thank you, sir.

THE WITNESS: Thank you, Mr. Examiner.

EXAMINER BRANCARD: Thank you.

Mr. Rose-Coss, any questions?

EXAMINER ROSE-COSS: Good afternoon again, Mr. Janacek. I (inaudible).

EXAMINER BRANCARD: Dylan, you're breaking up pretty badly. (Note: Pause.)

EXAMINER ROSE-COSS: Is that any better?

EXAMINER BRANCARD: Seems to be.

EXAMINER ROSE-COSS: Maybe I was just mumbling before.

(Note: Discussion off the record.)

EXAMINER ROSE-COSS: Thank you. I will attempt not to move.

CROSS EXAMINATION

BY EXAMINER ROSE-COSS:

Q. Mr. Janacek, would you explain for me again the philosophy around having multiple injection wells, and the -- what needs to happen in the field to turn one of the producers into the injector. Again just for my clarification.

A. Sure. So the philosophy is what you like to go through, and then you'd also like to talk about operationally what we need to change to turn a well into a CLGC well?

Q. (Note: Nods head.)

A. Okay. So the philosophy behind selecting these wells and using multiple wells is we're able to utilize our existing infrastructure and our existing gas lift system, instead of having to build out any additional facilities.

So because we're utilizing multiple wells at a lower pressure, we're able to inject the storage volumes to help us out during an event interruption but we don't require any additional compression be installed.

The additional compression would need to be installed if we were having one or two wells where we wanted to increase our surface pressure and simultaneously increase our injection rate, but here we've spread out our injection across multiple wells, a handful of wells, so we're able to inject at a lower rate and a lower surface pressure.

Does that make sense, Mr. Examiner?

Q. Yes. I see. So it's not that the well volume couldn't handle any one event, the reservoir volume, it's that you would need a higher surface pressure to achieve.

A. That's correct. So your surface pressure dictates, uh -- well, along with other things. But those that we can control, we can control the surface pressure for injection and we can control the compressors that we have that impact our surface pressures. And so if we

wanted to utilize less wells and take that approach, that would require additional compressor installations on the surface, but here what we are doing is utilizing a lower pressure and utilizing our existing infrastructure to make things a little bit more simple.

Q. Would it be possible -- in this scenario is it only one well at a time that will accept the injection, or could multiple wells accept it at the same time, and is the infrastructure able to handle the volume.

Like you say, if there is a big event and you're moving up to high volume, what happens then?

A. Good question. So the way it will work, that we envision it will work, is when we have a storage event and the pressure in the low-pressure gas gathering network starts to build up, we will turn on one well at a time, or activate one well at a time in a cascading fashion.

So we'll bring on one well. In this instance we have a selection of 11. We will bring on the first well and we will see if that is enough to bring down and keep our system pressure low. If it's not, then we will bring on a second well and a third well and a fourth well where we get to an equilibrium point where we are able to continue to produce all of our fluids into the system and we're able to store gas and keep the system in equilibrium.

So that's how we envision utilizing this batch of wells for a gas-storage event.

So it will kind of be: Use them as we need to, bring on one at a time, and then if the event is extended for a longer period of time, we may bring on all 11 of the wells.

So that's operationally how we see this project being operated.

Q. I see. Well, that's helpful, then.

You said one more thing in there that I'm going to ask for some clarification on.

You said "keep your system in equilibrium with production." Was I hearing that correct? Can you explain what you mean by that?

So within your system you also need wells producing at the same time, or no?

A. Yes. So the reason why we're pursuing -- that's a good question. I should clarify.

The reason why we're pursuing the closed loop gas capture, one of the reasons why is for us to be able to continue production of the offset source wells.

So if we have produced gas continuing to come out of these source wells and enter that network, it will need a place to go, so since we can't sell that gas, it will need to be stored and injected into these gas

storage wells.

So whenever I say "keep the system in equilibrium," I mean that for each standard cubic feet of produced gas that we are unable to sell, we'll need to inject and store that standard cubic feet in a CLGC storage well.

Q. I see. Perfect.

That relates to complications surrounding shutting in production; is that correct?

A. That's correct. So if we didn't have a place to put the one standard cubic foot of gas, then the next step would be to shut in those wells or flare that standard cubic feet to keep the system in equilibrium.

Q. And what's the problem with shutting in the wells again? Because the wells that are being injected into are essentially being shut in. Correct?

A. Yes. The injection wells are being shut in, and that's -- for short periods of time that is all right with us. It's just a matter of the other source wells, not having to shut them in.

Q. I see. Because if they're shut in they're not making money, essentially.

A. That's correct. We are not producing fluids.

Q. So the wells that are going to be continuing to be producing during this time are, say, the fresher wells

that are producing potentially better than the ones that are being selected as injector wells, or is that not the case?

A. I believe that is somewhat factored into our selection process, and our selection process was sent with the supplemental information for the past hearings that you-all can look at.

But in just speaking to it, yes, in general the other wells in the system, the source wells those probably have higher oil rates, higher gas rates associated with them.

Q. I see. Okay. Thank you. This was a helpful discussion for me, and I've exhausted the questions I have, so I'll past the microphone.

EXAMINER McCLURE: If I may, I do have an additional question, an additional line of topic I guess, if that is all right with you, Mr. Brancard.

EXAMINER BRANCARD: All right. Sure.

EXAMINER McCLURE: Being aware that we are past noon.

And maybe this is a better of line of topic to discuss on the reservoir side. I'm not sure. You know, I apologize for not asking it before. I didn't make a note of it, and when I was reading my notes to do my questions, I missed getting back to it.

FURTHER CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. I guess on the allocation method that you proposed on Slide 132, was there a specific reason, I guess, that these production periods were selected the way they were?

A. Production periods. What do you mean by that?

Q. Well, it almost seems like you kind of modeled it after the well-test requirements for the surface commingling permit, but those production periods for surface commingling are selected for specific reasons based upon the characteristics of the well during like a flowback period, immediately following the flowback period and starting to decline. And I guess I wasn't sure how relevant or how applicable they are to this scenario.

For instance, the initial production period that you have listed is until peak gas production rates are reached. Do you not think that your peak production gas rate will be reached essentially as soon as you turn the well back on, and it's going to immediately start declining?

A. Yes, we believe it will be that point in time.

Q. So then would it be correct to say that essentially the first period you have listed here, for all essential purposes doesn't even exist. I mean there is no

period there, because you're immediately going to the second period.

A. Yes, it will move forward to the second period.

Q. So then essentially what it looks like you were actually -- what you proposed here, and when you were making a proposal for the previous three cases, is you are essentially asking to only conduct three well tests per month after the injection period is over with.

Is that correct, then?

A. I believe so. I would have to look through the language and review it in detail.

Q. I was going to say, essentially -- I mean just a rough summary, and if there's anything that you think I'm incorrect on.

Essentially my understanding is it looks like you are wanting to do daily well tests for this initial production period, which actually doesn't actually exist, and then you immediately go to what the default is in the surface commingling permit, which is three well tests per month.

A. Yes.

Q. I guess unless you -- do you actually think that your recovery period would even last long enough for your well tests to even pick it up at all, then? And if not, how would you propose that you're even getting any numbers

based upon this proposal?

A. Could you repeat the question?

Q. Okay. If you are only doing three well tests a month --

A. Uh-huh.

Q. -- that means your recovery period would have to last at least greater than one week for you even to conduct a well test during that period. Correct?

A. Uh-huh.

Q. So I guess my question to you is: How would you suitably even see what they're looking like during that week, because won't there be a -- uh, won't there be a great deal of change, I guess, directly after initial production as you drop it back off to native production?

A. Yes. So the ** taper tester method that we've included there, and keeping in line with that verbiage as minimal requirements. We want to capture data at a higher frequency than that, than the three per month, but that is kind of our minimum that we'll be reporting.

So what we envision happening is right after we have a storage event we'll put a well in test for the first 24 hours after the storage event, and then a corresponding next 24 hours after a storage event so we have good data capture at the early time after a storage event. And then as we go out in time we will start to

space out the well tests and get them at a lower frequency.

Q. Are you envisioning -- when you refer to, uhm -- I'm getting it for the 24 hours afterwards. Are you referring to continuously monitoring it for that 24 hours or are you thinking more along the lines -- I think in your initial production period your proposal is six hours for the first day and then six hours for the next day, and then six hours -- well, until that initial production period.

But are you instead envisioning 24 hours, then, rather than a 6-hour period of that 24 hours?

A. Uhm, we're envisioning probably 24 hours for the first day, and then after the second day onward it being six-hour well tests.

Q. Okay. We are going to have a little bit more internal discussion. I was going to say I'm kind of looking at -- I mean, I think what we would be requiring would be far closer to what you would be envisioning, I guess, than what you're proposal is here, I guess, if that makes sense, I guess.

But, yeah, there's going to be some internal discussion. I don't know if we are going to need anything -- in fact I don't think we will need anything additional from OXY on it, but we'll essentially discuss

internally here and see exactly how we want to go about on our stipulations on what we are going to have within the Order.

A. If I may, I would like to explain another thing that I didn't point out previously.

Q. Go ahead.

A. In the example, and you'll see it there in detail, not only are we getting the well tests, you know, spaced out over time, but the data points that we're using in between the well tests are interpolated values.

So after the values have been interpolated based of our analysis, the difference between the well test and the calculated GOR volumes that we've seen in the continuous testing and what we've seen in the taper testing interpolative method, the error is less than 1 percent.

So we believe that this is a very accurate methodology whenever you apply the taper testing method and you interpolate the daily production in between.

Q. Well, I guess what sort of decline rate are you using to make that determination? Because we don't have any -- I mean, do you have any real data that you're putting that against, or are you just assuming such-and-such percentage of decline, or what are you thinking?

A. What we are doing is we're utilizing two data points in between tests. So I would test on Day 1 and then test on Day 3, and then the test on Day 2 would therefore be interpolated as the average between those two values.

So it's not based on any type of decline, it's based on the actual well test that we receive for the well.

Q. Oh, yeah. Yes, sir. Yes, yes, yes. I understand what you're getting at there. I guess what -- well, let me rephrase my question.

A. Sure.

Q. You made the determination that the error is less than 1 percent. How are you making that determination?

A. That determination was comparing the interpol- -- the cumulative gas production for each month using the interpolative methodology, and then comparing that to our simulation where we had the continuously tested data points for each day.

And so we compared those two volumes to see what the difference was, and it was a very low percentage.

Q. Okay. So then to get your -- I mean, well, I'll just refer to it as the "real production," I guess. But essentially -- or the actual production. To get that

value came from a simulation, essentially, then you just compared that to if you had conducted well tests at such and such a frequency and seen what your actual error was --

A. Right.

Q. -- a direct interpretation for the in-between your tests.

A. That's correct.

Q. Okay. Okay. I'm understanding where we're coming from now. I just didn't quite understand exactly what we were looking at.

I thank you for making that clarification and bringing that point out.

I was going to say in regards to this I don't think I have any other questions here. So thanks again for your time.

THE WITNESS: Thank you.

EXAMINER BRANCARD: Thank you.

Mr. Rankin, it appears that we are cutting into the noon hour here and you have two more witnesses.

MR. RANKIN: I do, Mr. Examiner, and we have two other cases.

So the other witnesses will be much more quick, but nevertheless, in order to sustain myself and yourselves, I think through the next cases, we might -- I

might request at this time to recess this case so that we may have a lunch break and then we can resume after the case that has been set for 1:00 o'clock this afternoon, if that is acceptable to the Division, unless you want to adjust the time frames this afternoon.

EXAMINER BRANCARD: Okay. You're willing to have your case be put off until later?

MR. RANKIN: Well, I understand we've set this other case at 1:00, and I discussed that with the folks at OXY.

I think, you know, I don't know that it would take much longer to get through the other three cases, this was the bulk of it, so we could potentially resume at 1:00 and try to finish these cases and then proceed with that special case for the Division.

EXAMINER BRANCARD: I believe you're involved in that case, also?

MR. RANKIN: Yes, sir.

EXAMINER BRANCARD: And do you think we can get done with that this afternoon?

MR. RANKIN: I do.

EXAMINER BRANCARD: All right. All right. Well, splendid idea.

So why don't we go on a lunch break until 1:15. Is that acceptable or do you need a little more

time?

MR. RANKIN: That works for me, Mr. Examiner, and I think it would work or the OXY folks, too.

Do you propose we resume with these OXY cases, or how do you want to proceed?

EXAMINER BRANCARD: Well, I like your idea about jumping to the OCD/SPC case. Let's see if we can get that done this afternoon, because we have told those witnesses that this afternoon is the time.

(Note: Discussion with counsel from other cases re timing reported but not transcribed herein.)

EXAMINER BRANCARD: Thank you. All right. So we stand in recess until 1:15. Thank you.

MR. RANKIN: Thank you.

(Note: Other matters heard. Case continued to September 10, 2021 at 9:00 a.m.)

FRIDAY, SEPTEMBER 10, 2021, 9:00 A.M.

EXAMINER BRANCARD: Let's go on the record.

Good morning. It is September 10, 2021. This is a continuation of hearings by the New Mexico Oil Conservation Division. I'm Bill Brancard, Legal Hearing Examiner. With me is Dean McClure, Dylan Rose-Coss, technical examiners. We have a court reporter, Mary Macfarlane, so please speak clearly and slowly and avoid barking dogs in the background

So where we left off we are on Cases 22150, 22151, 22152. And I believe, Mr. Rankin, you were starting with 22152, and we had had Direct Examination of Mr. Janacek, and there was some questioning. And I believe now is your chance for any redirect of Mr. Janacek, and we can being finish him up, if that's possible.

Please proceed.

MR. RANKIN: Thank you very much.

EXAMINER BRANCARD: First let me check. Is Mr. Bruce here? No?

Are there any other entries of appearance for these three cases, 22150, 22151, 22153? (Note: Pause.)

Hearing none, I think we are alone, so please proceed.

MR. RANKIN: Thank you, Mr. Examiner.

Mr. Janacek, Good morning.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. You recall yesterday Examiner McClure was asking some questions about OXY's proposed well tests allocation method. Will you please review, in light of those questions, OXY's proposal.

A. Sure. Can you hear all right? Okay.

Yes. I just want to provide some further comments on the taper testing methodology that we have attached as an exhibit.

So with the proposed taper testing frequency, we do plan to test as frequently as possible but with the equipment constraints with multiple CLGC wells and offset impacted wells going to the same tester, we've had issues acquiring data. So this is why we proposed the taper testing methodology, so we can have the flexibility, just like a commingling permit which utilizes a six-hour well test for reporting purposes and for determining our GOR-allocation calculations.

So I just wanted to provide that additional statement before we moved on. (Note: Pause.)

Adam, I don't know if you're trying to speak. I can't hear you.

MR. RANKIN: That's because I'm muted.

Q. And just so the record is clear, Mr. Janacek, OXY is not proposing that it is going to do only three well tests per month?

A. That's correct. That's kind of a minimum bar that we've set. We are going to try and obtain a lot higher frequency testing than that, especially after a storage event.

MR. RANKIN: Thank you. No further questions.

EXAMINER BRANCARD: Thank you.

Mr. McClure, do you have any follow up to that?

EXAMINER McCLURE: No, sir. No, sir, I don't have any follow up.

EXAMINER BRANCARD: Thank you.

So are you going to bring Mr. Janacek back for the next two cases or is this all three cases?

MR. RANKIN: Mr. Brancard, we would bring Mr. Janacek back just to touch on a few of the differences. It would take about five, ten minutes to do each of those other cases. My preference, I guess, would be to go through the geology and engineering and then to touch on the other testimony for each of the subsequent cases.

EXAMINER BRANCARD: Please proceed then with your, next, witness.

MR. RANKIN: Thank you, Mr. Examiner. Our next witness is Mr. Tony Troutman.

TONY JOHN TROUTMAN,

previously sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Troutman, are you there?

A. I am.

Q. Great. Let me know if you ever can't hear me. Will you state your name for the record, please.

A. Tony John Troutman.

Q. By whom are you employed?

A. OXY USA, Inc.

Q. And in what capacity?

A. As a petroleum geologist.

Q. Have you previously testified before the Division?

A. Yes, I have.

Q. Have you had your credentials as an expert in petroleum geology accepted as a matter of record?

A. Yes, I have.

Q. Have you conducted a study of the geology in the subject area in this proposed pilot project?

A. Yes, I have.

MR. RANKIN: At this time, Mr. Examiner, I would retender Mr. Troutman as an expert witness in petroleum geology.

EXAMINER BRANCARD: So approved.

Q. Mr. Troutman, did you prepare Written Testimony in this case?

A. I did.

Q. Has it been marked as Exhibit C?

A. Yes.

Q. Do you adopt that testimony as your testimony today?

A. Yes.

Q. And were the slides that you prepared in Exhibit A prepared by you or compiled under your direction and supervision or do they constitute OXY business records?

A. Yes.

Q. I'm going to direct you to those pages now, and then I'll admit your testimony shortly.

I'm going to share my page, Mr. Troutman. Let me know when you're able to see it.

A. I can see that.

Q. Great. This is page 77 of Exhibit A.

Does this exhibit show type logs for the Patton 18 Mdp1 Federal 6H well?

A. Yes, it does.

Q. Does it identify the two injection intervals that are going to be proposed for injection in this case with that green shading?

A. Yes, it does.

Q. And are the confining layers that you identified depicted on this type log with orange blocks?

A. They are.

Q. Okay. And the general geologic, uhm, nature of the stratigraphy and the overlying and underlying producing areas, are they identified on the left side of your exhibit here?

A. Yes.

Q. And the next slide here, this is the cross-section showing the same proposed injection intervals with green shading?

A. It is.

Q. And are the proposed wells that will be proposed for injection, are they identified with these red circles?

A. Yes, they are.

Q. And is that type log that we just went through, is that identified with the red star --

A. Yes.

Q. -- in the cross-section?

And are each of the recognized zones within

the Bone Spring identified on the side of the cross-section here?

A. Yes, they are.

Q. And then this next slide, is this a cross-section map identifying the wells that you used to create your cross-section from A to A-prime?

A. Correct. That's the location of the cross-section.

Q. And this red star is again the location of that type well log?

A. Yes.

Q. Are the wells that you used for this cross-section, are they representative of the geology in the area?

A. They are.

Q. Did you also prepare a detailed write-up of your geologic analysis for each of the injection intervals at pages 80 to 81 in Exhibit A?

A. Yes, I have.

Q. And did you also prepare a statement confirming that you have reviewed the geologic and engineering data and found no evidence of open faults or other hydrologic connections between the injection zone and any sources of drinking water?

A. (Note: No audible response.)

Q. In your opinion, Mr. Troutman, is the granting of OXY's application in this case in the best interest of conservation, prevention of waste, and protection of correlative rights?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of Exhibit C.

EXAMINER BRANCARD: Okay. Any objection?

Hearing none, the exhibit is admitted.

MR. RANKIN: Thank you, Mr. Examiner. At this time --

(Note: Reporter inquiry.)

MR. RANKIN: My apologies.

At this time I would move the admission of Exhibit C.

EXAMINER BRANCARD: We got that. So the next part.

MR. RANKIN: And then pass the witness for any questions by the examiners.

EXAMINER BRANCARD: Thank you.

Mr. Rose-Coss.

CROSS EXAMINATION

BY EXAMINER ROSE-COSS:

Q. Good morning, Mr. Troutman. Thank you for your presentation here. The questions I have pertain to I

suppose the nature of the difference in the formations between what is being dubbed the injection interval and what is being dubbed the barriers to migration within the Bone Spring, broader Bone Spring.

Could you go ahead and tell me a little bit about the difference between the rocks that we see there, and why is the landing zone the landing zone, and why are the barriers the barriers. You know, beyond the description of the rocks, the kind of description of what happened depositionally, and maybe some inferences.

I think -- I guess we can see from the cross-sections that they are laterally continuous, but maybe a little bit of discussion about that.

A. Well, we have two landing zones represented there. One is the Middle Avalon and the second is the Second Bone Spring Sand.

Both of those -- Middle Avalon is a silty mudstone, so its a fairly low permeability zone, and -- and -- anyway, it's surrounded by lower permeability carbonates, and that's the same situation for the Second Bone Spring Sand which is a siltstone. Below it is the Third Bone Spring Carbonate that is low permeability and low porosity, and above it is the First Bone Spring Carbonate -- or a Second Bone Spring that is also low permeability and low porosity.

So both of those act as frack barriers and permeability barriers.

Q. I see. So it's -- and the -- the carbonates and the siltstone, is there a difference in composition between the rocks, or why is one -- is it silty, like a carbonate-rich siltstone, or is it just the grain size difference?

A. The carbonates are highly cemented with low porosity, and they are primarily dolomite. Not that the dolomite itself is all that significant. The dolomite is harder than limestone so it creates and even stronger barrier to fracturing.

The siltstone that is the reservoir is composed of fine-grain Aeolian sands.

Q. Okay. So the silt in the siltstones is Aeolian in nature.

A. It is.

Q. What happened in the carbonate that it wasn't getting -- this is kind of, you know --

A. These are sea-level changes that change the composition of what was deposited. So as sea level went down you get more sands coming into the basin, and as sea level goes back up the carbonate factory around the edges of the basin reactivates and you get more carbonates feeding off into the basin, and you don't get the sand

because it's got further to travel to get there.

Q. Okay. And those are the landing zones?

A. The landing zones are in the silts.

Q. Okay. And can you describe for me, too, then, the -- as we keep going down section, Harkey Shale and then below that is the Wolfcamp, and I've seen in some of the other cases that maybe there's some discrepancies between when it's the Wolfcamp and when it's the Harkey Shale. Is that a thing? And what happened between the Wolfcamp and the Bone Spring, and would you see any potential problems with injecting, say, the Bone Spring gas into the Wolfcamp, or vice versa.

A. Uhm, okay. I'll start with the Harkey first. The Harkey is part of the Third Bone Spring Lime. It's just a subdivision within the Third Bone Spring limestone.

So it's got limestone above it and below it, and here in this area we've got what we are calling the Harkey Shale. There isn't a formal name for the Harkey Shale, but it's simply designated that because it's a little deeper and a little shalier than what's called the Harkey Sand.

The Harkey Sand is a somewhat common drilling target across the Basin, and it's within the Third Bone Spring. This Harkey Shale just happens to be below that Harkey Sand, so we've given it that name for

our purposes.

Q. There's a proper sand down there, because the signature looks similar to the limestone. But somehow there's a limestone and then there's the sandstone, and then you're in the shale --

A. Right. And that sand is probably the Harkey Sand, I think, that you're referring to.

Q. I'm on page 84 of 150 looking at the column on 35 Fed 175H, which I believe is the one that had...

Oh, this is -- I'm sorry, I'm in 22151 and we are speaking about 22152.

They're burned together for me here.

So that would be my question for 2215 -- and the --

A. You also asked me about the Wolfcamp.

Q. Yes. Yes, I did.

A. Now, we're not involving the Wolfcamp in these because we're above the Third Bone Spring Lime on this location. But where the Third Bone Spring Sand and the Wolfcamp have a contact, there's really no barrier. There's a minor barrier that consists of a bentonite clay that may be a few inches thick. It's not significant to fracking and it's not very significant to oil and gas migration.

So those two reservoirs can communicate.

Q. I see.

A. The Upper Wolfcamp Sands and the Lower Third Bone Spring Sands is what I'm referring to.

Q. You know, were we to see these Bone Springs and Wolfcamps and outcrops, would you be able to tell the difference where the contact was, or what's the difference between these rocks?

A. That bentonite is about the only way to identify that contact.

EXAMINER ROSE-COSS: Okay. Gotcha.

Well, that just about, I think, exhausts my general questions about geology, so I'll pass the witness. Thank you.

THE WITNESS: All right. Thank you.

EXAMINER BRANCARD: Thank you.

Mr. McClure.

EXAMINER McCLURE: Yes, sir.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. I was going to say I don't have a whole lot of questions. I guess only really two.

Have you seen any indication that the fractures may have extended beyond the target zone for any of these production wells that we're talking about here?

A. No, I haven't.

Q. And then the other question I had, more just of a legend question -- well, confirmation, because I think it's probably pretty clear, but just to have it within the transcript.

On your Slide 90 of 153, those orange highlighted areas, those are what we are considering the confining layers, correct? You would consider all those layers to be confining?

A. Yes.

Q. Okay. Thank you. Yeah, I was going to say the legend was there, but it's kind of off the page a little bit. I guess it's not really off the page, it's more like we have a stamp that was put into it by our system that maybe covered up that line of the legend, actually, the more I look at it.

But, anyway, I think that's all the questions I had for you. Thanks for your time.

THE WITNESS: All right. Thank you.

EXAMINER BRANCARD: Mr. Rankin, any redirect?

MR. RANKIN: No, Mr. Examiner. We would ask that Mr. Troutman be dismissed until we recall him for the next cases.

I would ask our next witness, Ms. Xie, be called to the stand.

EXAMINER BRANCARD: Okay. Did you have any

exhibits to admit?

MR. RANKIN: I think we admitted Exhibit C. Hopefully. Maybe that's when I was on mute.

EXAMINER BRANCARD: No, you did. Thank you. Okay. Fine. Next witness, please.

MR. RANKIN: Thank you. Our next witness is Ms. Xueying Xie.

THE WITNESS: Good morning.

XUEYING XIE,

previously sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good morning, Ms. Xie. Could you please state your full name for the record and spell it for the benefit of the court reporter.

A. Yeah. Xueying Xie. First name IS X-u-e-y-i-n-g. Last name is X-i-e.

Q. Thank you. And by whom are you employed?

A. OXY USA.

Q. In what capacity?

A. As a reservoir engineer.

Q. Have you previously testified before the Division?

A. Yes, I did.

Q. Were your credentials as an expert in reservoir

engineering accepted as a matter of record?

A. Yes.

Q. Did you prepare written testimony in this case that was filed and marked as Exhibit D?

A. Yes.

Q. Do you adopt your written testimony as your testimony today in this case?

A. Uh-huh. Yes.

Q. Were the slides that you prepared as part of Exhibit A prepared by you or under your direction and supervision, or do they constitute OXY business records?

A. Yes. Yes, it was. It is.

MR. RANKIN: Thank you. At this time, Mr. Examiner, I would go ahead and move the admission of OXY Exhibit D into the record.

EXAMINER BRANCARD: All right. Are there any concerns from anyone?

Hearing none, so admitted.

Q. Ms. Xie, have you examined the available geologic data and found no evidence of open faults or other hydrologic connections between the injection zone and any underground source of drinking water?

A. Yes.

Q. And did you include in Exhibit A a signed statement to that effect?

A. Yes, I did.

Q. I'm going to go ahead and have you walk us through a little bit in summary, high-level summary, your analysis that supports this application that you've included in your Exhibit A.

And I'll go ahead and share a different screen. Not looking at -- I picked the wrong screen.

So we can go through your slides.

Let me know when you're able to see the screens.

A. Okay. I can see.

Q. Looking at Exhibit 4, is this a high-level summary review of what you did in preparing this model for this case?

A. Yes.

Q. And your next slide, page 85, does this explain more about the origin of the model that you used that came from the Cedar Canyon Huff-n-Puff project in the nearby area?

A. Yes.

Q. And for purposes of this analysis is the Cedar Canyon area similar for purposes of modeling the system?

A. Yes. They have similar reservoir properties and the fluid properties.

Q. As a reminder for the examiners, in your

testimony did you conclude that because the Huff-n-Puff project and the model that you used from the Cedar Canyon, you were able to identify actual gas breakthrough over a period of three months, and that the injection was at a higher pressure than what is proposed here and at higher rates, and you have confidence that your model will be able to predict whether, at what point, if at all, there will be gas breakthrough in the proposed injection for this case?

A. Yes. So we have high confidence about the model because the model is based on the actual geology data, and which capture the communication distance and inject in (inaudible).

Q. Now looking at your next slide, slide 6, does this reflect the parameters that were used by you to construct your model?

A. Yes. It shows the detailed model.

Q. And it demonstrates that you were able to tune the model to the data; is that correct?

A. Yes. It matches all the rates and the injection pressures.

Q. What does this next slide show?

A. This next slide shows that the base on the gas EUR project model, which was tuned to reflect the production and the injection pressure and the

communication distance, injectors and producers, now based on that model we created a basic model without any injection for a reference, and then we create multiple CLGC models to investigate the difference in injection scenarios, and then compare with the base case to understand the impact of the gas injection on the CLGC wells and its offset producers.

Q. And explain, if you would, just briefly what does this next slide explain.

A. This one integrates the wellbore model with the reservoir model to predict the injection rate for a 5,000-feet lateral length well. When tubing has injection pressure of 1200 psi we can see that the initial maximum rate is 1.5 million mmcf per day. After 21 days the injection rates declined by 50 percent.

For our next numerous CLGC injection cases study, we used more conservative case, meaning we use cost and the injection rates at 2 million mmcf per day to study the worst case.

Q. Just as a reminder, in this all the proposed injection wells are at approximately 5,000-foot laterals; is that right?

A. Yes, they are.

Q. And then if you would just briefly explain what this next exhibit shows.

A. This one shows the gas movement in the reservoir after we injected gas by the gas saturation contour plot.

Let's look at the top-left plot first. In this plot the east-to-west lines are the horizontal wells, the middle one is the injector, and the northeast to southwest lines are fractures, so just directly 45 degrees to the wellbore.

And the color shows the gas saturation. The blue color shows low gas saturation, zero gas, and the cyan color show some gas saturation; I think maybe 20 percent. And the cyan color is happening in these fractures so we do know there is gas in the fractures.

And then we compare the gas movement based on gas saturation before injection and after injection. The middle plot shows the gas saturation after one week of injection and in the middle well. We can see that the middle well the color becomes warmer. That means it has more gas. The warmer the color the more gas saturation.

And to see it clearer, we maximized the plot at the bottom near the injection well, so the bottom wells show that near injection now the color clearly is warmer compared with the upper plot.

And we also check the distance. We find that the distance -- like, within 100 feet it has some gas saturation change; however, after 100 feet away from

wellbore we don't seen gas saturation change anymore. So we concluded that with this CLGC gas injection -- because we don't inject that much gas, so gas doesn't migrate far away, further away from 100 feet.

Then the top-right plot shows that, uhm, a few months, actually 16 months after production, we start post the injection. And with that much time in production, we can see that the nearer the injector the color becomes cyan again, so no more extra gas near wellbore. That's because majority of the gas produced back.

Q. And the next slide here on page 90 shows essentially the same thing except looking at pressure around the wellbore; is that correct?

A. Yes, correct.

Q. And that same conclusion looking at pressure.

A. Yes.

Q. And your next slide here, review, if you would, just what these different cases -- what this chart means and what you conclude based on the information here.

A. Yeah. We ran numerous case studies of CGLC projects. Here in the table is listed the eight cases in the table. The second column shows some scenario, description of the scenario. So it includes like a single-well injection and a multi-well injection, well

injection. And like in Case 4 it has single-well injection but with multiple cycles. Like injection/production/injection/production. I think it has three cycles.

And then Scenario No. 5 it's single-well injection but has higher injection rate and longer injection periods.

Q. Oops. Sorry.

A. Then the third column that we see means well protection, shows well spacing. We tested four to eight well protection scenarios. In general OXY now has four-to-six wells per section.

So eight wells per section in the lateral case, we use it as the worst case scenario to check the nanospacing, and the right three columns shows the results. It shows there's no impact on the injection, CLGC injection well production, and also shows no impact on the offset-well production.

And the last column shows that there's no gas breakthrough predicted from the model in all these cases.

Q. Did you do any -- and I think you covered this, but the worst case was -- your overall was your Case No. 5; is that correct?

A. Yes. Even with the worst case we don't see any

impact.

Q. And the worse case is based on actual experience that OXY has had of the maximum number of days of downtime based on a downstream gathering-system upset?

A. Yes, based on the oil fields in New Mexico. So in the field we apply for Permian actually is less than that. Usually it's less than six days.

Q. That's the average downtime, and the worst case in the history of all of New Mexico has been 21 days; is that correct?

A. Yes.

Q. Thank you. Did you do a cross-check to confirm the volumes OXY proposes to inject would be accepted by the injection interval?

A. Yes.

Q. Your model says so, but you also conducted a cross-check to confirm?

A. Yes.

Q. Does this exhibit on page 2 explain that in your review?

A. Yes. So the paper shows all eleven wells in the application, and the right two columns shows the gas storage capacity. And if we just base on the fracture volumes the capacity is over 100 mmcf. If we base on the produced fluid equivalent, gas equivalent, then that's the

last column that shows a large volume. So usually it's above 600 mmcf.

For the injection wells, CLGS injection, the maximum volume we expect is 60 mmcf, so it's way below the volume capacity.

Q. Did you also prepare calculations reflecting the stimulated reservoir volume?

A. Yes. That calculation is based on the fracture dimension, which is based on (inaudible) for frack model.

Q. And then finally, did you prepare a statement confirming that you prepared this analysis and found that total recoverable hydrocarbons will not be adversely affected by the project and that the gas composition will not damage the reservoir?

A. Yes.

MR. RANKIN: Thank you very much, Ms. Xie.

At this time I would -- I have no further questions and pass the witness for questions by the examiners.

EXAMINER BRANCARD: Thank you.

Mr. McClure.

EXAMINER McCLURE: Yes, sir.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. I guess I did have, I guess, a couple of quick

questions. Well, hopefully quick.

OXY submitted some previous cases, three previous cases like around about a month ago. Just for reference for reviewers, those would be Cases 22087 through 22089. For your reference, that's the Mesa Verde, the Taco Cat and Avogato.

The model that was used in those cases and the model used in these three cases, was there any changes made within that model between these six cases, I guess?

A. No, there's no change made. All the reservoir properties are similar.

Q. Sounds good. Sounds good. I kind of assumed, but I wanted to confirm for sure.

Now, on Slide 104 when we are talking about your different simulation cases that you would run, you reference that there's no gas breakthrough. I guess my question is: As far as pressure change in the offset wells, was there any pressure such that production was affected within the offset wells, might be a better way to ask the question.

A. No, there is no effect, and the pressure of offset well has no change.

Q. Okay. Sounds good. I may have asked this a month ago, I don't remember, but I'd ask again if I hadn't.

Now, if I recall you had put in some connecting fractures between the three wells in your matching for your -- I think it was matching with the Huff-n-Puff, your Huff-n-Puff EOR project.

A. Yes, you remember correct on that.

Q. Now, the reason for that is because in that particular case you did see some pressure communication between the production wells and the -- or the injection wells and the offset wells; is that correct?

A. You are correct. We observed communication after three months of injection. In the first three months we don't see anything.

So the communication -- the connected fractures there, just the conductivity looks like very weak so there's no immediate breakthrough.

Q. And do you think the reason for that was you had to increase your pore pressure such that it opened those fractures, or do you think it's just that the connectivity was just so low that it just took that long for it to get over there?

A. The second reason, I think.

Q. Low connectivity. Okay. I'm with you.

A. Right.

Q. Or low permeability. However, whatever you want to call it. Okay. And like I said, I probably asked all

those questions before. I just don't recall for sure if we'd covered all that.

Then I guess I'll just ask you the same question, I guess, as I asked your geologist: Have you seen any indication that any of the fractures in these production wells may have fracked out of the targeted formation, that being the Bone Spring One and the Bone Spring Two here, I believe.

A. It's all within the Bone Spring. If you're talking about the detail, like Second Bone Spring, if it goes to Second Bone Spring Lime or Third Bone Spring Lime, it might go like 20 feet or 40 feet, but our lime is very thick so it will not go through the lime.

Q. And are you basing that off of modeling or do we have -- it seemed like maybe you compared your modeling to some microseismic results, but I don't recall.

A. Yes, we have microseismic, and we also have some other diagnostics, like Revocam (phonetic), Oxy DNA (phonetic).

So we integrate all these observations together to understand the pressure height.

EXAMINER McCLURE: Sounds very good. Sounds very good.

Okay. I'm thinking that there is all the questions I had. Thank you for your time.

THE WITNESS: Thank you.

EXAMINER BRANCARD: Thank you. Mr. Rose-Coss any questions?

EXAMINER ROSE-COSS: You know what, actually I did have questions, and as we continued to discuss topics, the testimony answered them. So I thank you for that Ms. Xie, and appreciate your time this morning.

THE WITNESS: Thank you.

EXAMINER BRANCARD: Thank you.

Mr. Rankin, any redirect?

MR. RANKIN: No, sir, no redirect. No further questions. I ask that Ms. Xie be excused and be permitted to ask that this case be taken under advisement.

EXAMINER BRANCARD: Okay. So Mr. McClure, Mr. Rose-Coss, do we have any specific requests for information at this point?

EXAMINER McCLURE: I think the only specific request that I recall was only on the AOR map, just to have the laterals depicted upon the map that has the Excel tables number formatting.

EXAMINER ROSE-COSS: No questions, and no additional submissions required that I asked for. Thank you.

EXAMINER BRANCARD: Is that clear, Mr. Rankin and Mr. Janacek?

MR. RANKIN: Yes, it is. I believe we understand that we will provide updated AOR maps for each of the six cases, even the previous ones that were submitted in the August hearing date.

EXAMINER BRANCARD: Okay. Good. I always want to sort of recap what was requested along the way so we make sure that we're getting everything we need. Thank you.

So Case 22152 is taken under advisement, with further discussions, if necessary.

And please proceed now with which case would you like to move forward with, Mr. Rankin.

MR. RANKIN: Thank you, Mr. Examiner. We would like next to call Case 22151.

EXAMINER BRANCARD: All right. Please proceed.

MR. RANKIN: Than you very much. At this time Mr. Examiner, we call our first witness, Mr. Stephen Janacek.

Mr. Examiner, I guess because we've gone through the routine here, I'll ask that he be qualified as an expert in this case, as well, at this time.

EXAMINER BRANCARD: So qualified.

MR. RANKIN: Thank you.

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Janacek, have you prepared Written Testimony in this case that's been marked as Exhibit B?

A. Yes, I have.

Q. And do you adopt that testimony today as your sworn testimony in this case?

A. I do.

Q. Did you also prepare additional exhibits that have been marked as Exhibits B-1 through B-6?

A. Yes.

Q. And did you also prepare, uh, or coordinate the preparation of what has been marked as Exhibit A, which is the application and the application materials that were submitted to the Division?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of Exhibit A and Exhibits B-1 through B-6.

EXAMINER BRANCARD: So admitted.

MR. RANKIN: Thank you very much.

Q. Now, at this time Mr. Janacek, rather than go through your full written testimony and summarize it, as we did previously, I'm going to ask you if you would just on point out to the examiners sort of the operational key differences between this case and the previous case that we just reviewed in Case 22152.

A. Sure. So there are a lot of similarities between this case and the previous. Just some minor tweaks and changes.

Just going through the highlights, the first of which is the Maximum Allowable Surface Pressure will be 1250 psi, utilizing our existing systems.

There are seven wells in this application. All of them will be injecting down the casing tubing annulus with a packer in the hole.

As far as the well lateral length, six wells are 5,000-foot lateral length, approximately, and one well is a 10,000-foot lateral length, the Iridium well. So that's where you'll see in some of the information a difference in the injection rates that we expect for this group of wells.

As far as the targeted formations we have in this project, we are targeting three. The first is the Avalon, the second is the Second Bone Spring, and the third is the Harkey. So we can go through those in detail, if need be, later on.

And finally another thing to note here is that in this instance we are asking for the ability to add wells administratively to the injection order if they are within the AOR area.

So those are the key highlights for this

case.

Q. Mr. Janacek, as with the prior case you're also asking for the ability to extend administratively the authority to inject beyond the initial two-year period?

A. Yes, we are.

Q. Okay. And otherwise the structure of the application, the materials that were provided, they all follow the same format as the previous case?

A. Yes, they do. There's also an additional request regarding the packer setting depth that we go through in detail in the application.

Q. And then as to the additional materials that were submitted, the gas allocation method, the well test method, the Data Collection Plan, all those proposals are the same as for the prior cases?

A. Yes, that's correct.

MR. RANKIN: At this time, Mr. Examiner, I would pass Mr. Janacek for questions by the examiners.

EXAMINER BRANCARD: Thank you. Did we have the exhibits be admitted?

MR. RANKIN: I believe we've admitted Exhibits A and then B and B-1 through B-6, which included the Notice exhibits. I didn't go through those in detail but I'd be happy to review those for the examiner, if he would like me to do that.

EXAMINER BRANCARD: No, that's fine. I just want to make sure we've got the exhibits.

So who's ready to go? Mr. McClure?

EXAMINER McCLURE: I certainly can.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. I was going to say in this particular case, the 22151, this is another subset of Surface Commingling Order or Permit PLC 749; is that correct?

A. That's correct.

Q. And is it also correct in this case, as well, that only the wells that are included here, 110 wells, are the only wells that could be source wells, and the other wells within the 268 that's included in PLC 749 cannot actually get their gas into your gas lift system. Correct?

A. That's correct. If you're referring to the gas source well list on page 48 of 150 through 50 of 150, yes, those are the only wells in this gas source system.

Q. Sounds very good. Yes, those are the pages I was referring to. I believe it's 110, but my count could be off. There's three pages of them. But essentially I was just confirming that.

Then I guess I did have a question which I guess also relates to all three of these cases.

In this particular -- in these cases now you're asking for the administrative approval of additional wells. I guess, what is the difference between these three cases and the three cases from a month ago where you're now requesting that approval where you didn't a month ago, I guess. Is there anything different here?

A. Sure. There's nothing different. All the projects are very similar. It's just one thing as we continue to work through these projects and mature these projects. And these projects we've had a lot of discussion internally at OXY as a great idea. And so in order to expand this as easily as possible we included that request for these projects. If we would have thought of it sooner we would have done it for the previous batch, as well.

Q. Very good. Yeah. That's -- I think once we get out of pilot project stage that line of thinking is definitely something that's going to be a part of the guidance. It's just not in the guidance quite yet.

I guess if we could maybe get a little more detailed into that, just assistance for us when we go to start putting out guidance for that, is your thinking that maybe once you start getting results from these you may find that some of these perform less and maybe you need to have additional wells in the injection system, I guess, or

as additional injection wells to make up your volume? Or what is your thoughts for wanting to have the additional -- or the ability to add additional wells?

A. Yeah, the ability and the reasoning behind the request is mainly due to creating opportunity for operational flexibility. There's events that happen that are out of our realm of control, and so being able to have as many wells as possible to use as injectors if there is an upset event is just a lot easier for us as an operator.

An example of that that recently happened was earlier in 2021, I believe it was, one of the gas processing plants was struck by lightning and they had to wait on a mother board for a period of weeks. And so that's something that we can't control, and also leads into a longer period of potential gas storage event. So being able to utilize as much wells as possible, add them as easily as possible, gives us the most operational flexibility to reduce our flaring and store the gas instead.

Q. Very good. I guess my concern there, and it seems like you don't have it included in your proposal here, is as far as Notice requirements for adding additional wells. It seems like maybe you're proposing not to have Notice.

What is your thoughts in regards to that?

A. I don't have any thoughts at the moment, but I can definitely think on it and give you some feedback.

MR. RANKIN: Mr. Examiner, I might interject and just say that generally, traditionally where the application has requested that relief, at the time in the initial application the Notice has been achieved by, you know, giving the parties advance notice that the Applicant is seeking administrative approval to add additional wells administratively.

And in this case it's in the body of the application with our materials.

EXAMINER McCLURE: You make a good point, Mr. Rankin. I'm just sitting here thinking, because theoretically I guess it would just be a matter of whether the wells within this half-a-mile radius, that all the ownership was theoretically noticed. Although having said that, the concern would be if one of those wells then brought in additional -- I mean, for instance let's say you're 3/8 of a mile to the east, then a half a mile around that well if it were to bring in additional, or other parties into the original Notice, I guess would be my only consideration there.

MR. RANKIN: Right. Yeah, if there were additional Noticed parties as a result of the inclusion of new wells, in other words would expand the Area of Review,

then of course we would have to give Notice, and that would be part of the administrative application. But the point I guess would be rather than having to go to hearing it could be addressed administratively.

EXAMINER McCLURE: Okay. I'm thinking we're on the same page. I'm not in disagreement, I guess, with anything that was being stated here. That's not to say that such approval is going to be granted in this particular instance, but just for future considerations for us.

Q. Okay. Now, in regards to your wells, the lateral that's two miles long, ends with the 21H, like IRI 124 -- 28, 28-21H, in that particular well you have the same proposed average injection rate. You only increased your maximum injection rate. Are you kind of thinking that that well is going to take the same amount, then, as the other wells? Is it like it's a two-mile long lateral, so only the ability to add additional injection, or what are you thinking there?

A. What page are you referencing?

Q. Oh, I'm sorry. Slide 44 of 150. It's your table with, like, your engineering calculations for burst and such.

A. Yes, I see there. Yes. The IRI, that's the Iridium with the 10-K-lateral well you are referring to.

Yes, that-is-probably-an-error. That average injection rate will probably be higher than the other wells since it has a longer lateral.

Q. Okay. Yeah, I wasn't sure, I guess, as to what the thought was as to what's limiting your injection rate there, or what we were looking at.

But anyway, I think that answered my question there.

How much -- I guess you just have a rough estimate of how much higher your average injection rate might be. Obviously it's kind of off the cuff at this point.

A. Yeah, at this point in time I don't know what our average rate is going to be. The one thing that we really modeled and focused on here was our maximum injection rates, which obviously would be higher whenever we are starting out.

But I guess our average injection rate will vary depending upon the length of the storage event, because our rate will decrease over the length of a storage event.

So at the end of day, with the nuances of it, our average injection rate will vary for each storage event length.

Q. Yeah, that's a good point.

So then when you put together this table are you kind of predicting on the lower, as far as duration?

On the -- maybe let me rephrase that question.

When you put together this table, considering that your proposed average injection rate is close to your proposed maximum injection rate, was your line of thinking that the duration of injection events would be relatively short, and maybe thinking along the lines of like 12-hours-type thought process? What were you kind of thinking?

A. Yes. So this table was put together considering the modeling inputs that Reservoir worked on, as well as the current gas lift injection rates that we see during daily operations.

So it was a combination of those two that led us to build this table.

So that's where it came from, and I believe the focus was on the shorter events, because that's what we expect the majority of these events to be, are shorter storage events less than 24 hours in length.

Q. And, if I recall, there's only very limited number in OXY's history of events that had lasted longer than 24 hours. Is that correct?

A. That's correct. Xueying can talk more to it because she remembers a little bit more of the details on it, but if I recall correctly there's very few storage events that have lasted for a long, extended period of time, and that period of time being, you know, a period of weeks.

EXAMINER McCLURE: And I was going to say that's kind of what my memory is kind of recalling, because I think we went over this a month ago, if I recall, but maybe we will cover it real briefly again in this case, just to put it into this set of transcripts. Yeah.

Then I don't think I have any other questions. Thanks a lot for your time.

THE WITNESS: Thank you, Mr. Examiner.

EXAMINER BRANCARD: Mr. Rose-Coss, anything for this witness?

CROSS EXAMINATION

BY EXAMINER ROSE-COSS:

Q. You know, Dean's question about additional wells kind of within this geographic region that are, like, listed on a central tank battery or a commingle but not in this gas distribution pipeline connected with these, could you go into a little bit more about that?

Part of me is curious about just operationally how some of theses things are set up, like

why -- how this area and set of wells would look together, and your different project areas were defined and established.

A. Sure. If I refer to one of the pages in the exhibit, it will probably be easier to explain what we have going on here, Mr. Examiner.

So if you turn to page 18. Oh, there it is. Thank you, Adam. Yes.

Here we're looking at page 18 of 150 in the exhibits. This is a project map zoomed out looking at what we call the Sand Dunes area. And that's kind of all this area is what we call the Sand Dunes. Then when we zoom in we split it up a little bit further.

So the area on the upper half of the page, that's the case that we're talking about right now, called the North Corridor area, which includes the Cal-Mon wells and the Iridium wells, and on the bottom half of the page, that's the Patton area known as the South Corridor area that we just spoke about in the previous case.

So this is kind of a high-level picture of where they are in relationship to one other. So to further provide some clarification, all of the wells that are included in the commingling permit are connected to this blue low-pressure gas pipeline network. That's the Enterprise line here. And they are all connected to that

pipeline.

Now, as far as the red systems, those are isolated, and once gas leaves the red system and enters that blue system, it cannot go back to the red system. So that's how all of the wells on the commingling permits are related. They sell gas eventually to this blue Enterprise pipeline, and then the gas source wells, that's a smaller subset of wells that Dean was referring to where we have the isolated systems.

Q. Okay. There's additional wells out here that are on there that aren't connected to the red pipeline, they tap into the blue pipeline?

A. That's correct. For illustration purposes for these applications we only included the systems that were relevant to these projects, but there's a whole host of other red low-pressure pipeline systems for all of our leases in the area that pertain to the other wells listed in the commingling permit.

Q. Okay. Well, that explains it, a lot of that.

And I guess there's no -- I guess there's not -- it seems -- I'm comparing it again to EOG, what they presented, which might or might not be fair, but there's no other way pipelines connecting -- I'm pointing at the screen right now, gesturing with my hand -- this Iridium area and Patton area to communicate. Like, this

Iridium area and the Patton area can communicate with each other, and this is everything that's in Case -- everything, all the wells being included in Case 22150, but there is not a way for the wells in 22151 to communicate with each other.

A. Yes, that's a great question that we looked into ourselves and verified.

There are check valves where those systems connect, so once the gas enters the blue pipeline it can't flow back to either system, so therefore neither system can communicate with the other.

Q. I see. And just for clarification for me, too, so like in my mind I'm imagining a cluster of wells around the Cal Mon area, say, or the Iridium area, but then the shutdown is going to happen at that blue star, say. That's where the backup's going to begin.

How -- what's the methodology for routing the gas to either the Iridium area or the Cal Mon area? It could happen to all three at once, or is that shut-out is going to affect all of these equally, say?

A. Good question. So if there's a shut-in on the Enterprise line it depends upon how much of a reduction in capacity they have. It could be the whole line is shut down and that impacts all three of our project areas, or it could be a partial capacity reduction where it only

impacts one of them.

So what can happen is either situation, Enterprise has shut-in or an interruption could occur and all three of these areas are impacted at the same time, or it could be just one is impacted and the others are able to continue to sell gas to Enterprise.

Q. Okay. Because I'm thinking that there's just more wells that could be contributing to the Cal Mon area, so those -- than say the furthest one to the left that doesn't have a particular area labeled. And so there would be more volume in the red pipeline from the east moving to the west than the volume in the west moving to the east.

So you would need potentially more injectors off to that Cal Mon area?

A. Could you rephrase that again? I'm trying to...

Q. I'm sorry. I'm trying -- like, not being able to just point at what I mean.

So the volume in the Cal Mon area, right?

A. Okay.

Q. In those red pipelines could be greater than the area to the left or the west in those pipelines. So to the Cal Mon area there's -- and I suppose each of those red stars, those are flares, not injection wells.

A. That's correct. All of those red stars are

flares.

Q. Okay. And so where are the injection wells in relation to this pipeline? Okay. It's on this one.

A. So -- yes. So if we go to the next slide and we zoom in, this is on the Iridium well, the Iridium area, so we're looking at its relationship to the pipelines, the red pipelines that we saw on the previous page.

So keep in mind that the red pipelines are where all the gas is collected from different central tank batteries.

Q. Uh-huh.

A. And then it can be sent to any of the compressor stations or any of the sales points.

So this gas can move east, west, wherever we need it to be within those sub areas.

And then to also kind of talk about the wells on the west side, uh, on this where you see on the left -- Adam, could you go back one? Thank you.

So if we're looking on the left-hand side here and you see the Precious (phonetic) CTP there that's listed?

Q. Yeah.

A. So that's where we have a lot of newer development coming in and newer wells being brought on line, so they have a lot more gas associated with their

production. And then all of that gas, once it goes to that central tank battery, it could then enter the red low-pressure pipeline and head wherever. It can then travel well over to the east, east through this red pipeline, and then if we skip, I think it's two slides -- or maybe the next one. Yeah.

So that gas can still just go east and it can make its way over here to these Cal Mon wells.

Q. I see. Okay. It's gathered at the central tank batteries and then routed wherever it needs to be.

A. That's correct. It's all -- that's the beauty of this central gas lift network is we can utilize and route gas wherever we need to within these systems and be able to have the operational flexibility there to inject more gas into the gas lift wells, or in this instance utilize wells for gas storage.

Q. I see. And does this -- operationally what happens is that the blue pipeline, the gas takeaway pipeline, is that something that Enterprise has created to service these central tank batteries or is there other operators and producers out here feeding in at different places to these -- this same blue pipeline?

A. That's a good question. I don't know what the other operators are out here, but I would suspect there's probably some other operators out here that utilize the

same Enterprise gas pipeline here.

Q. Okay. And should that pipeline have the same downtime, places where I see the red stars, they are just flaring?

A. Yes.

Q. And that's what's happening now?

A. Yes. So we would -- if we have any upset now, we flare or shut in our production.

EXAMINER ROSE-COSS: Yeah. Okay. Just making that all clear in my mind again.

I believe that's all my questions for the moment, so thanks for walking me through it again.

THE WITNESS: Sure. No problem.

EXAMINER BRANCARD: Okay. Mr. Rankin, more questions for Mr. Janacek?

MR. RANKIN: No further questions for Mr. Janacek at this time.

EXAMINER BRANCARD: So I think I noted that -- was there one slide that needed to be updated? I think it was Slide 44. Mr. McClure raised a question about injection rates.

THE WITNESS: Uhm...

MR. RANKIN: Mr. Brancard, I think Mr. McClure's questions were about the proposed average injection rates, and I don't know that Mr. Janacek can confirm -- I don't

know that the slide could be updated.

THE WITNESS: I don't know it would be necessary to update, because here we are focusing on our maximum injection rate and those average injections rates can vary based off of the length of the storage event.

So I would just only note that yes, like Dean indicated, we are probably going to have a higher average injection rate for the 10,000-foot lateral well versus a 5,000-foot lateral well.

EXAMINER BRANCARD: Okay. I just wanted to make sure whether we needed anything new submitted. That's all.

THE WITNESS: Thank you, Mr. Examiner.

EXAMINER BRANCARD: All right. Mr. Rankin, please proceed with your witnesses.

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

At this time I would ask that Mr. Janacek be excused from the stand and we call our second witness in this case, Mr. Tony Troutman.

EXAMINER BRANCARD: Please go ahead.

MR. RANKIN: Thank you very much.

Mr. Examiner, Mr. Troutman has previously been qualified. I just ask he be recognized as an expert in petroleum engineering in this case, as well.

EXAMINER BRANCARD: So recognized.

MR. RANKIN: Thank you.

TONY TROUTMAN,

having been previously sworn testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Troutman, have you prepared Written Testimony in this case, and it's marked as Exhibit C?

A. Yes, I have.

Q. And do you adopt your Written Testimony today as your testimony in this case?

A. Yes, I do.

Q. And were the slides that you prepared in Exhibit A for this case prepared by you, compiled under your direction, or do they constitute OXY business records?

A. Yes, they were.

MR. RANKIN: Mr. Examiner, I would move the admission of Mr. Troutman's Written Testimony marked as Exhibit C into the record.

EXAMINER BRANCARD: Thank you.

Any concerns from any of the parties? Hearing none, so admitted.

MR. RANKIN: Thank you, Mr. Examiner.

Q. Mr. Troutman, I'm going to review with you, as I did previously, your slides you prepared in Exhibit A.

I'll put them up here on the screen, and let me know when you can see them.

A. I see them.

Q. Mr. Troutman, Exhibit -- or page 71, slide 71 of Exhibit A, does this represent the type log of the -- using the Cal Mon 35 Federal 17 71H well?

A. Yes.

Q. And as with your previous testimony have you identified the three proposed injection intervals with green shading in this type log?

A. I have.

Q. Have you also identified what you have indicated are confining layers in the -- with the orange blocks on the left side of that type log?

A. That's correct.

Q. Have you identified an overall analysis of the geology and stratigraphy, including the overlying or nearby producing on the left side of the exhibits?

A. Yes, I have.

Q. And on your next slide, is this a slide showing the cross section you prepared using representative wells in the area?

A. Yes.

Q. Does it also show, using green shading, the proposed injection intervals and that they are consistent

across the proposed injection area?

A. Yes, it does.

Q. Does it also identify the injection wells with red dots?

A. Yes.

Q. And just so it's clear, because I think the question was asked previously, are those confining layers consistent and do they exist across the proposed injection area?

A. They do.

Q. And is the type log identified on your cross-section with an orange -- red star?

A. Yes.

Q. And the next slide, is this just showing the structure map showing the location of the wells you used to create your cross section?

A. Correct.

Q. And also identifies the type log with the red star?

A. Yes.

Q. Did you also prepare a detailed write-up analyzing and reviewing the geology for each of the three injections intervals within the Bone Spring Formation?

A. I did.

Q. And those are included at pages 74 to 77 of

Exhibit A?

A. Yes.

Q. Finally, did you also prepare a written statement confirming that you reviewed the geologic engineering data and found no evidence of open faults or other hydrologic connections between the injection zone and any underground sources of drinking water?

A. Yes.

MR. RANKIN: And that's at page 78 of Exhibit A.

At this time, Mr. Examiner, I have no further questions of Mr. Troutman and would pass the witness for questions by the examiners.

EXAMINER BRANCARD: Thank you.

Let me just check in with the court reporter. Mary, how are you doing?

(Note: Pause.)

So, Mr. Rose-Coss, questions of the witness?

EXAMINER ROSE-COSS: No additional questions, thanks, Mr. Brancard.

EXAMINER BRANCARD: Thank you. Mr. McClure?

EXAMINER McCLURE: I don't have any additional questions for this witness. Thank you.

EXAMINER BRANCARD: Splendid.

Mr. Rankin, you may proceed.

Thank you, Mr. Troutman.

MR. RANKIN: Thank you, Mr. Troutman.

At this time we would call our third and final witness, Ms. Xie.

THE WITNESS: Yes.

MR. RANKIN: Ms. Xie, you have previously been sworn and recognized as an expert in reservoir engineering.

Mr. Examiner, at this time I just want to confirm that she is qualified as such.

EXAMINER BRANCARD: Still qualified.

XUEYING XIE,

previously sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Ms. Xie, you prepared an analysis of the reservoir engineering and a model, as you have in the previous cases, for this case?

A. Yes, I did.

Q. Did you also prepare Written Testimony in this case marked as Exhibit D?

A. Yes.

Q. Do you adopt your Written Testimony as your testimony today in this case?

A. Yes.

Q. And were the slides that you prepared in Exhibit A prepared by you or compiled under your direction or supervision?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would move Exhibit D into the record.

EXAMINER BRANCARD: All right. Any objections? Hearing none, so admitted.

MR. RANKIN: Thank you, Mr. Examiner.

Q. Ms. Xie, in the analysis that you prepared and the modeling that you did in this case, is it the same as the previous cases that we have discussed today?

A. Yes.

Q. And in your analysis you have come to the same conclusions, that the gas as proposed to be injected will not go beyond approximately 100 feet from the wellbore of the injection wells?

A. Yes.

Q. And you have also concluded there will be no adverse impacts to the reservoir as a result of the injection?

A. Yes.

Q. And also that there's no impact as a result of the gas composition into the reservoir?

A. Yes.

MR. RANKIN: Mr. Examiner, at this time I would pass Ms. Xie for further questions by the examiners.

EXAMINER BRANCARD: Thank you. Mr. McClure?

EXAMINER McCLURE: Thank you.

CROSS EXAMINATION

BY MR. McCLURE:

Q. I guess the only question I guess I had here was just in continuance of my original -- my earlier questioning, I guess, in regards to injection events.

If my memory recalls, there was only a limited number of injection events in OXY's history that lasted longer than, say, one day. I just was hoping for confirmation on that, if you know kind of what the history is there.

A. Yes. So in these two applications for the North Corridor the average interrupted duration is about one day, and then the maximum, I think, is four days in last year.

Q. You're saying your average is less than one day or is one day? I'm sorry, I didn't hear you quite right there.

A. Actually, as far as I know, it's around -- it's about one day.

Q. Is the average.

A. Yeah, is the average.

Q. Okay. I gotcha.

Do you kind of know, I guess, how many events maybe lasted more -- or (inaudible) like greater than two days, then, or do we kind of have some sort of breakdown there?

A. I don't have a number in my mind but I do know that maximum is four days.

Q. Okay. Sounds good. Sounds good. Okay. I was just trying to kind of get a rough idea, I guess, in my head of what we are looking at there. So you're saying four.

Does that cover all three of these cases, then, kind of that thought process, or is like the Cal Mon different than the Patton and the Cedar Canyon?

A. No. Cal Mon and the Patton are the same, the maximum is four days, and the Cedar Canyon is different. The Cedar Canyon maximum is two days.

Q. Okay. And then on average, is this average also less or is it still about a day?

A. Cedar Canyon average is less than one day.

Q. Okay. Very good. Very good. Okay.

And I was just hoping, trying to get a rough idea in my head as we are looking forward on what we're looking at here. I think that there answered all my questions. Thank you.

EXAMINER BRANCARD: Thank you.

Mr. Rankin, any further...

I'm sorry, did we get Mr. Rose-Coss already?

EXAMINER ROSE-COSS: You didn't, but it's okay. I don't have any additional questions.

EXAMINER BRANCARD: All right. Good.

With that, Mr. Rankin?

MR. RANKIN: No further questions of this witness, Mr. Examiner, and I would ask at this time that Case 22151 be taken under advisement with the understanding that we will submit an updated AOR map as Mr. McClure has requested, showing the wellbore trajectories in the same map as the Excel well numbers.

EXAMINER BRANCARD: Excellent. Thank you. So I think that's it for that case.

So Case 22151 will be taken under advisement.

We can now move to Case 22150, and I guess I will just check once again to see if Mr. Bruce is with us, because he did enter an appearance in this case.

Any other interested parties in this Case 22150? (Note: Pause.) Hearing none, you may proceed, Mr. Rankin.

MR. RANKIN: Thank you, Mr. Brancard.

At this time I would like to turn over the controls to my colleague Kaitlyn Luck, who will be presenting this case.

MS. LUCK: Thank you.

So in terms of this case we understood that there would be no objection from Matador to proceeding with testimony as filed on Tuesday, so I would like to just first turn to our first witness, who is Mr. Janacek. And his testimony was prefiled on Tuesday.

STEPHEN JANACEK,

previously sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

Q. So as previously recognized in the last hearing, Mr. Janacek can you state your full name for the record.

A. Yes. My full name is Stephen Janacek.

Q. Thank you. And again, you're employed by OXY; is that correct?

A. That's correct.

MS. LUCK: And in the past two hearings the Division recognized you as an expert in petroleum engineering matters, and so we would ask that he also be recognized in this case.

EXAMINER BRANCARD: So recognized.

MS. LUCK: Thank you.

Q. So without reviewing all of the slides again, I'd like to just highlight the main differences between this case and the prior cases, if you wouldn't mind just explaining that for us.

A. Sure. In this case, the Cedar Canyon Gas Storage Project, we are requesting a Maximum Allowable Surface Pressure of 1250 psi.

And there are three wells in this application. All three of these wells will have injection down the casing tubing annulus with a packer in the hole.

All of these wells are 5,000-foot lateral length, and all of these wells will be targeting the Second Bone Spring as the storage formation.

Another thing to note here is that with the proposed Data Collection Plan we did not attach a gunbarrel view because of the orientation between some of the wells, so in this case we have attached a map of all the wells that are offset in the Cedar Canyon area that are producing from the Second Bone Spring.

Another thing to note is when you look at the process diagram, there are two separate high-pressure gas lift systems, so we have two separate orange lines in this area. And the reason why that is, is because through the middle of our Cedar Canyon development we have the Pecos River running through it, so we built two separate

high-pressure gas lift systems, one for the east area east of the Pecos River and one for the west area west of the Pecos River.

And then two other things to note are the request for the specific packer setting-depth language that is included, as well as the ability to add wells administratively to this project.

And that's a summary of the Cedar Canyon Project and the difference between this project and the previous ones.

Q. Thank you. And so as a part of the materials that were submitted, I just want to confirm that YOU prepared Written Testimony which has been included as Exhibit B.

A. Yes, I did.

Q. And so do you incorporate and adopt that as your sworn testimony into this case?

A. I do.

Q. And did you also prepare what has been marked as Exhibits B-1 through B-6 in this case?

A. Yes, I did.

Q. And did you also coordinate or compile the information included in Exhibit A, pages 3 through 68, which were the Application and materials submitted to the Division?

A. That is correct.

MS. LUCK: So with that I would move the admission of Exhibits A and B, as well as the accompanying B-1 through B-6 in this case.

Then I just wanted to cover a few more points just to clarify that the requests are being made into this case.

So in this case is OXY also requesting a two-year term for this proposed closed loop gas capture injection project?

A. Yes.

Q. Is OXY also seeking to administratively add injection wells to that project that are within the Area of Review if the need arises?

A. Yes.

Q. And, finally, is OXY also seeking the authority to administratively extend the authority under the Order?

A. Yes.

Q. Thank you for that.

And so with that, that concludes all of my questioning for this witness and I would turn him over to the examiners for any other questions.

EXAMINER BRANCARD: Thank you. Are there any objections to these exhibits? Hearing none, they are so admitted.

Mr. McClure, any questions.

EXAMINER McCLURE: Yes, sir, I do.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. On your maps and on your, uh, storage process flow diagram, it does look like you do have the ability to divert flow to either side of the Pecos River. Is that correct?

A. Which item are you looking at there?

Q. Page 15 and page 16.

A. Yes.

Q. It looks like there is a red line that crosses the Pecos River, and then on page 16 you don't really -- it doesn't look like there's a divide that could go to either one of the lift systems.

A. That's correct.

Q. Okay. Is that correct?

A. The low-pressure line crosses the Pecos River. So we can send gas to either system.

Q. Okay. I just wanted to confirm. I was -- from looking at this I was reasonably certain, but your testimony regarding having the two different systems, I guess I just wanted to confirm.

Now, this system here covers wells that's within PLC 750; is that correct?

A. Yes, that's correct.

Q. Now, PLC 750, it looks like you have all 147 wells listed as source wells that could come here; however, on these maps, on again page 15 and page 16, it seems like those batteries that's included within that service commingling is not included here.

So I guess is it accurate to say that the gas from those other wells could be sourced to here?

A. Yes, it is accurate. We just showed a portion of the red low-pressure gas line here, but that low-pressure line extends up and away to other central tank batteries in the area that those source wells produce to.

Q. Okay. So then just to confirm, there is additional low-pressure line that extends to the north and the northwest, if memory serves, to bring in the other batteries within that system, then.

A. That's correct.

Q. Okay. Okay. I was kinda -- I felt like I was speculating, because I actually wasn't sure. I wasn't sure if there was an error there or if there was an error in the map, I guess.

A. It's a good question, because we try to put together the maps to explain the project, but, as you're aware, they are a very complicated system with a lot of

wells leading into it, so it's difficult to do.

Q. Yeah, I was going to say I guess in the interest of I guess maybe conformiality, I guess, between all these different ones, I guess how difficult would be to put together an additional map that does include the entire system for the PLC 750 that we're sourcing here?

A. I don't know if it's been done before, and that's not my area, but I'm sure I could speak with the OXY team and see if that's something we could put together.

Q. I guess maybe I'll just ask the question of my fellow tech examiner.

Dylan, what's your thoughts? Is that something that would be of interest for us to see?

EXAMINER ROSE-COSS: Say it again what you're looking for exactly.

EXAMINER McCLURE: Their map that shows their system does not include the entirety of their system. We're aware of the additional wells, I guess because I am familiar somewhat with their system here, but we don't actually have it included within this case. So I wasn't sure -- would it be of interest to yourself and us if we do have them go back and produce a complete map of their system and submit it to us?

EXAMINER ROSE-COSS: You know, I --

EXAMINER McCLURE: Does my rambling explanation make sense?

EXAMINER ROSE-COSS: Yeah. I suppose I'm interested, but in thinking off the cuff here, not knowing if it makes a difference in terms of any language that I would include in the Order.

EXAMINER McCLURE: It won't make a difference there. It's a matter of making -- making ease for yourself to become familiar with the system. Like I say, I have a general idea of what we're looking at, regardless. I wasn't sure what your thought was.

EXAMINER ROSE-COSS: Uhm, I'm making my mind up here on the spot.

I'm curious, but is that an onerous thing for y'all to do, Mr. Janacek? Do you think it will make it a very busy, hard-to-read figure, or is that something you can --

THE WITNESS:

EXAMINER ROSE-COSS: -- (inaudible) with?

THE WITNESS: You know, it will be, to be honest, pretty tedious to pull and verify all of those lines and shake figures to build a map, because it was kind of onerous to build just these maps.

So if that's something you-all really want to see, we can put it together. And it will probably take

a little bit of time, but we thought that just showing the main elements that are included in this system and associated with the storage wells would suffice, and then just providing a list of source wells, noting that, hey, the red low-pressure system extends throughout the area.

EXAMINER ROSE-COSS: I don't always take into consideration the orneriness of a request when I'm making one, but I don't feel especially inclined to ask for it at this point.

EXAMINER McCLURE: Nor do I.

With that in consideration we'll not need an amended map to be submitted to us, then. (Note: Pause.)

You know. I don't think I have any other questions. Thank a lot for your time.

THE WITNESS: Thank you, Mr. Examiner.

EXAMINER BRANCARD: Mr. McClure, can you hear me?

EXAMINER McCLURE: Yes, sir. I'm sorry. Go ahead, Bill.

EXAMINER BRANCARD: I'm having technical difficulties here in the building because the drilling is so bad, so I'm wondering if you can just sort of finish up this hearing as the examiner.

EXAMINER McCLURE: Sounds good. Sounds good.

Hopefully I won't forget anything, though.

EXAMINER BRANCARD: Yeah We just have two more witnesses to get through and then just take it under advisement when we're done.

EXAMINER McCLURE: Sounds very good.

EXAMINER BRANCARD: You can probably hear the drilling right now, I'm sure.

EXAMINER McCLURE: Thank you.

EXAMINER BRANCARD: I can barely hear anybody at this point.

EXAMINER McCLURE: All right. Sounds good. We got it, Bill.

EXAMINER BRANCARD: Thank you.

EXAMINER McCLURE: Ms. Luck, do you want to call your next witness?

MS. LUCK: Yes. So now I'd like to call Mr. Tony Troutman.

TONY TROUTMAN,

previously sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

Q. Mr. Troutman, can you state your name for the record.

A. Tony Troutman.

Q. And by whom are you employed and in what

capacity?

A. OXY USA, Inc. as a petroleum geologist.

Q. And you were previously recognized as an expert in the past two cases; is that correct?

A. Correct.

MS. LUCK: So I would ask that Mr. Troutman be recognized as an expert in petroleum geology in this case.

EXAMINER McCLURE: So recognized.

Q. So, Mr. Troutman, in preparation for this case did you prepare some Written Testimony?

A. Yes.

Q. And was that included with OXY's exhibit packet as OXY Exhibit C?

A. Yes.

Q. And did you also prepare a portion of the Exhibit A attached to the application included as Slide 60 through 66?

A. Yes.

MS. LUCK: So with that I would move the admission of Mr. Troutman's testimony as Exhibit C, as well as the portions of Exhibit A that were referenced.

EXAMINER McCLURE: Are there any objections?

Hearing none, so brought into the record.

MS. LUCK: Thank you.

Q. So I'll go ahead and share my screen so Mr.

Troutman can see the slides that were referenced just now.

Okay. Can everybody see my screen --

A. Yes.

Q. Okay. With this slides.

So starting -- This is page 60 of the Exhibit A that was included with the application. And this is -- sorry, I'm just scrolling back up.

Can you explain for the examiners --

A. Sure.

Q. -- in the Second Bone Spring Formation involved in this case, as compared with the past two cases that were presented?

A. Yes. The well log on the right is a type log in this area, and the green highlighted zone is our injection zone here, which is Second Bone Spring Sands.

And on the left side I've put in descriptions of the barriers and to permeability and flow out of the Second Bone Spring Sand zone, and I've also identified productive zones above and below it.

Q. Okay. And in this case is it correct that OXY's targeting the Second Bone Spring Sand?

A. Correct.

Q. So turning to this next slide -- let me just pull back up here -- can you just explain your opinion as to this project's impact on any fresh water aquifers in

the nearby area?

A. Yes. If you look at the well log on the right, at the top of it you can see at that point the lowest fresh and brackish water aquifer is in the Rustler Formation, which is above the Salado and the Castile. So it's several thousand feet above the Second Bone Spring Sand, which is at the very bottom of this well log.

Both the Salado and Castile and barriers within the Bone Spring will prevent communication with fresh water aquifers.

Q. So does your exhibit included as page 62 of the application depict a type log for the project area and the proposed injection zone, as well as adjacent oil and gas zones, to reflect that there are confining layers for this project?

A. Yes. And this slide is simply a more-detailed version of those type logs -- of that type log showing the full section in detail and showing the deeper sections, which also have barriers that would prevent downward flow of this injected gas.

Q. Okay. And then can you explain anything significant that needs to be pointed out on this slide, Slide 63, as part of the Exhibit A to the application regarding the cross-section?

A. Sure. The green highlighted zone is the Second

Bone Spring Sand; the three red dots show the location in vertical distance of these three injection wells; and the little map inset on the right is a structure map of the Second Bone Spring Sand.

Q. And so also included, sorry, is your structure map and isochore map of the project area as well; is that correct?

A. Correct.

Q. And can you let us know or confirm the thickness of the Second Bone Spring Sand in this area?

A. This is the structure map. The next slide is the isochore map which shows the thickness.

So the thickness is rather consistent across this area. We're looking at basically 300 to 400 feet in thickness.

Q. Okay. And is it your opinion there's no evidence of faulting pinchouts or other pathways for migration between the zones in this area?

A. Correct.

Q. Is it also your opinion that this area in the Second Bone Spring Formation is suitable to have the proposed project?

A. Yes.

Q. And then did you also prepare this page 6 of the Exhibit A that reflects there's no evidence of open faults

or other hydrologic connections between the disposal zones and other underground sources of drinking water?

A. Yes, I did.

Q. And is it, finally, also your opinion this project is in the best interests of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, it is.

MS. LUCK: Thank you. So with that, that concludes my questioning for this witness, and I would turn him over to the examiners for any other questions.

EXAMINER McCLURE: Thank you.

Did we already take these exhibits in the record?

MS. LUCK: If not, I would move the admission of the portions of Exhibit A that Mr. Troutman prepared, which are specifically pages 0 through 66, and then his Affidavit Prefiled Testimony, which is Exhibit --

EXAMINER McCLURE: I think actually maybe we did already take those exhibits in, but if there are any objections -- or are there any objections to taking those exhibits, if we haven't?

Hearing none, so brought into the record.

Mr. Rose-Coss, did you have any questions for this witness?

EXAMINER ROSE-COSS: No, Mr. McClure, I do not at this time. Thank you. Thanks again, Mr. Troutman.

THE WITNESS: Thank you.

EXAMINER McCLURE: I don't have any questions, either. Thank you.

MS. LUCK: Thank you. So if there is no further questions for this witness, I would like to call our final witness, Ms. Xie, again to the stand.

XUEYING XIE,

previously sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

Q. Hi. Can you please state your name again for the record.

A. Xueying Xie.

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

A. OXY USA as a reservoir engineer.

Q. And in the past two cases your credentials have been previously accepted by the Division and you have been recognized as an expert witness in reservoir engineering; is that correct?

A. Yes, that's correct.

MS. LUCK: Thank you. So I'd go ahead and tender Ms. Xie again as an expert in petroleum reservoir engineering.

EXAMINER McCLURE: So accepted.

MS. LUCK: Thank you.

Q. Ms. Xie, are you familiar with the application filed by OXY in this case?

A. Yes, I am.

Q. Did you also take part in the preparation of Exhibit A to the application in this case?

A. Yes.

Q. And specifically those are pages 68 through 78 of the application?

A. 66 through 78.

Q. Okay. That's correct, yeah. Excuse me. I Misspoke. 66 through 78.

A. Uh-huh. Yes.

Q. And so today do you -- excuse me.

Do you also accept and incorporate the testimony that was prefiled by OXY into this case as Exhibit D?

A. Yes.

Q. So I'd like to just briefly review any differences in this case as compared to the past two cases, because we would also like to incorporate your testimony in cases -- excuse me, in the accompanying cases that we presented today.

Those are 22151 and 22152, so if you could

just please highlight any differences. And I can share your exhibits on the screen for us to review, if you would like to go through them one by one, but otherwise just note any differences.

A. Actually there's no differences except, like, in each individual well has different storage capacity and different SRV. Other than that, there was no difference.

Q. Okay. And I guess is there anything further on these slides that should be pointed out to the Division examiners to highlight the difference in the well capacity or the SRV?

A. No.

MS. LUCK: Okay. Also with that, then, I would just move the admission of these slides, which are pages 66 through 78 to the application, and then also Ms. Xie's Prefiled Testimony which we filed as Exhibit D.

EXAMINER McCLURE: Any objections?

Hearing none, so brought on the record.

MS. LUCK: Thank you. So I would just turn over Ms. Xie to the examiners for any questions.

EXAMINER McCLURE: Thank you. Mr. Rose-Coss any questions for this witness?

EXAMINER ROSE-COSS: No additional questions. Thank you, Mr. McClure, Ms. Xie.

EXAMINER McCLURE: I have no questions, either,

for this witness. Thank you.

MS. LUCK: Thank you.

Thanks again. And if there's no further questions for any of the witnesses, then that would conclude OXY's presentation of this case. Of course if there is any further questions following the hearing we're happy and available to answer those questions.

EXAMINER McCLURE: All right. Sounds good.

Are you wanting this case to be brought under advisement, then?

MS. LUCK: Yes, that would be my request.

I just want to confirm that all the exhibits have been moved into the record, so Exhibit A through D in the exhibit packet, and then I would ask the Division take this case under advisement.

EXAMINER McCLURE: All right. Any exhibits that haven't been brought into the record can now be brought into the record, and this case, Case No. 22150, is taken under advisement, with the record left open for the submission of those -- of the updated or new AOR map with the laterals depicted, as was mentioned in the other cases.

Ms. Luck, I don't know if Mr. Rankin had mentioned it, but we just want to make sure that Mr. Bruce got a copy of these submissions, as well, when they were

made.

MS. LUCK: Yeah, we sent him copies of these exhibits on Tuesday or Wednesday after they were filed, but we will make sure that he gets copies of those updated AOR maps when we send them in to the Division, too.

EXAMINER McCLURE: Very good. Very good.

I guess with that done, I don't know as there's anything else we need to do before we close out the hearing.

MS. LUCK: I don't think we have any further business of OXY's, but thank you for your time. We appreciate you guys listening to these cases, and let us know if you have any questions.

EXAMINER McCLURE: Thank you for the time, as well. And with that, I think we can bring the hearing to a close and go off the record.

(Time noted 10:55 a.m.)

STATE OF NEW MEXICO)
) SS
COUNTY OF TAOS)

REPORTER'S CERTIFICATE

I, MARY THERESE MACFARLANE, New Mexico Reporter CCR No. 122, DO HEREBY CERTIFY that on Thursday, September 9, 2021, the proceedings in the above-captioned matter were taken before me; that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability and control.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with (unless excepted by the rules) any of the parties or attorneys in this case, and that I have no interest whatsoever in the final disposition of this case in any court.

/s/ Mary Macfarlane
_____

MARY THERESE MACFARLANE, CCR
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