PUBLIC HEARING

STATE OF NEW MEXICO

OIL CONSERVATION COMMISSION

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1220 S. Saint Francis Drive

Santa Fe, New Mexico

TRANSCRIPT OF PROCEEDINGS

April 21, 2025

VOLUME XII

HEARD BEFORE:

HEARING OFFICER RIPLEY HARWOOD

COMMISSION MEMBERS:

GERASIMOS ROZATOS, Chair

BAYLEN LAMKIN, Member

DR. WILLIAM AMPOMAH, Member

COUNSEL TO THE COMMISSION:

MR. ZACHARY SHANDLER, ESQ.

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I N D E X

(On the record at 9:02 a.m.)

TRANSCRIPT OF PROCEEDINGS

CHAIR ROZATOS: My name is Gerasimos Rozatos. I am the acting director of the Oil Conservation Division. I'm also the acting Chair for the Oil Conservation Commission.

Today is April 21st, 2025. We have our meeting and hearing today. So what I would like to do is start our meeting this morning, and I'd like to do a roll call.

As I stated, I am Gerasimos Rozatos. I am the acting director, and the acting Commission Chair for the Oil Conservation Commission. And then I'll turn it over to Commissioner Bloom. I'll start with you.

COMMISSIONER BLOOM: Good morning, everyone. Thank you, Mr. Chair. Greg Bloom, designee of the commissioner of Public Lands. And I am just here, I think, for the Apache and Northwind cases. And I'll step out and Baylen Lamkin will take my place for the Goodnight/Empire case. Thank you.

CHAIR ROZATOS: Commissioner Ampomah.

COMMISSIONER AMPOMAH: Good morning. I'm Dr. William Ampomah, professor of petroleum engineering at New Mexico Tech, and also designee of the Energy secretary. Thank you.

CHAIR ROZATOS: Excellent. Thank you.

And just to let everybody know, Mr. Zachary Shandler is also going to be appearing via Teams this week, as well. So he will be on platform also if we need anything.

Excellent. So our roll call is done.

So let's move to the approval of the April 21st through the 25th, 2025, agenda. May I get a motion for that approval.

COMMISSIONER BLOOM: Mr. Chair, I so move.

COMMISSIONER AMPOMAH: I second.

CHAIR ROZATOS: Excellent. Thank you. So the agenda for this meeting has been approved.

(Motion approved.)

CHAIR ROZATOS: Our third item is the approval of the March 11th, 2025, meeting minutes. Commissioner Bloom, I just wanted to make sure. You had wanted some time to be able to review it. Were you able to review the minutes?

COMMISSIONER BLOOM: Mr. Chair, yes, I did. I suggested a couple corrections, and I think those sent around by Sheila, so we should be good for a motion on that.

CHAIR ROZATOS: So you're moving for the

motion.

If we could get a second, please.

COMMISSIONER AMPOMAH: I second.

CHAIR ROZATOS: Excellent. So those minutes have been approved, as well.

(Motion approved.)

CHAIR ROZATOS: I don't know if Mr. Shandler is on right at the moment. But did we have any pending litigation?

As I stated, I don't think he's on right at the moment. So I don't think we have any other pending litigation. And did we have any other business that we needed to address, Commissioners?

COMMISSIONER BLOOM: No, Mr. Chair.

CHAIR ROZATOS: Commissioner Ampomah?

COMMISSIONER AMPOMAH: No.

THE CHAIR: So our next meeting is scheduled for May the 15th, 2025. So let's mark that on our calendars, as well.

We did have some cases that we wanted to do before we actually went into the actual hearing.

So our first pending case is Case Number 24881, application of Northwind Midstream Partners, LLC, for approval of an additional redundant acid gas injection well, and to amend Order Number R-20913, as amended, and SWD-2622, to authorize an increased shared maximum daily injection rate in Lea County, New Mexico.

Are all individuals for this particular case present?

MR. RANKIN: Mr. Chair, Commissioners, Adam Rankin with the Santa Fe office of Holland & Hart, appearing on behalf of Northwind Midstream Partners, LLC.

HEARING OFFICER HARWOOD: Thank you, Mr. Rankin.

MR. TREMAINE: This is Jesse Tremaine for the Oil Conservation Division.

CHAIR ROZATOS: Excellent.

Mr. Rankin, so this is a presentation of final order, correct?

MR. RANKIN: Correct, Mr. Chair. We circulated a proposed draft final order middle of last week, for the Commission to review and consider, proposing the adoption or granting of the application, as requested, with the modifications that came up from the hearing and adopting the Division's proposed conditions as modified during the hearing.

CHAIR ROZATOS: Mr. Tremaine, just making sure that you agree and you have no issues?

MR. TREMAINE: We reviewed the proposal and agree with the content.

CHAIR ROZATOS: Commissioners, did you have any questions on the final order?

COMMISSIONER BLOOM: No, Mr. Chair.

COMMISSIONER AMPOMAH: No, Mr. Chair.

CHAIR ROZATOS: Excellent. Okay. So we will process that final order and we will continue on with that.

Any questions, Mr. Rankin or Mr. Tremaine?

MR. RANKIN: No. Thank you very much Mr. Chairman, Commissioners.

MR. TREMAINE: None for OCD. Thank you.

CHAIR ROZATOS: Excellent. Thank you. So that one is completed.

We'll move on to Case Number 24912, the application of Apache Corporation for an adjudicatory hearing to contest the Division's condition of appeal on Apache Corporation's scope of work for additional investigation in Lea County, New Mexico. It's a matter to be heard. Motion to amend Order R-23728.

Are all parties present?

MR. MOELLENBERG: Mr. Chair, Members of the

Commission, Dal Moellenberg, from Gallagher & Kennedy, for Apache Corporation. Along with me is Samantha Catalano.

CHAIR ROZATOS: Thank you, Mr. Moellenberg.

MR. TREMAINE: And this is Jesse Tremaine for the Oil Conservation Division. Thank you.

CHAIR ROZATOS: Excellent. Thank you.

Mr. Moellenberg, we'll turn it over to you for your motion.

MR. MOELLENBERG: Thank you, Mr. Chair, Members of the Commission.

You'll all recall that we had a hearing in this matter in January. We then had an order that was issued by the Commission in February. Apache moved for rehearing of that matter. The Commission didn't act on that; so with that, the order became final, other than subject to a court appeal.

Since the hearing, Apache had conducted another round of groundwater monitoring, reported the results to the Division, and also conducted, along with others, some of the investigations prompted by the groundwater monitoring conducted before the hearing.

We then, after reporting those results, consulted with the Division, and discussed whether we could reach agreement on a slightly modified groundwater monitoring plan, after having looked at all of the additional information.

We were able to come to an agreement on that. The agreement makes some slight adjustments to some of the monitoring wells. There are, I think, about four fewer monitoring wells. But, essentially, the monitoring wells that were dropped are, more or less, replaced by a good spacing around the perimeter of the area. I would say the interior monitoring wells have largely been untouched.

The joint motion on behalf of the Apache and the Division summarizes those changes for you, provides a map. And with that, we would ask the Commission's approval of the joint motion. And along with the joint motion, there is and Exhibit A that would be essentially the new directive for groundwater monitoring at the site.

CHAIR ROZATOS: Thank you, Mr. Moellenberg.

Mr. Tremaine.

MR. TREMAINE: Thank you, Mr. Chair, Commissioners.

As you recall, we had a contested hearing in this matter. I think a couple things to point out are that at the time of the hearing, we had

had fourth-quarter monitoring that was concerning to the Division. And the consultant -- or new consultant for Apache was newer to the case.

Since that order was issued, we've had multiple meetings with Apache and the consultant. OCD has reviewed the technical aspects of the revised proposal and met all of the asks that OCD has made in terms of content of the reports and the sampling. This does revise the position of certain of the wells.

But this is -- this proposal is well within a range that OCD was seeking when we went to hearing, so we are satisfied with this as a worthwhile proposal in terms of the next step of remediation and characterization.

So I agree with Mr. Moellenberg that certain of the wells that are removed are replaced based on the positioning of other wells. There are some other changes, such as there are areas of concern identified by both OCD and Apache related to landscape scarring, potential sources of the chlorides from historic or potentially newer releases.

And so some of the wells have been changed to a monitoring well downgrading of that location, but a soil boring in the scarring location. And we think that that is actually a net positive from the result of the hearing. That was something that was not discussed before.

And lastly, one of the primary objectives of the Division in this case was to get us to a resolution on the next stage of characterization and identification of contamination. We believe that this does that, because with this proposal, Apache will waive their right to appeal. And there are still legal arguments between the parties.

So we believe that this is something the Commission should strongly consider and we ask you to approve. It gets us to where the Division believes that we need to be for the next stage of remediation and, in a modified way, it achieves, we believe, what the order issued by the Commission would have achieved.

THE COURT: Thank you, Mr. Tremaine.

Commissioners, any questions?

COMMISSIONER AMPOMAH: Mr. Chair, do we have a map for the new proposed locations?

CHAIR ROZATOS: I am not sure. I know the exhibits were submitted. I am kind of looking through it myself. My apologies.

Exhibit A does not have a map on it.
There was also an Exhibit B.
COMMISSIONER BLOOM: Exhibit B does have the map, yeah.
CHAIR ROZATOS: Yeah. It's on Exhibit B.
Mr. Moellenberg, I will ask a question. So on this Exhibit B, the wells that are designated as new, 1 through 6, are the new wells, correct?
MR. MOELLENBERG: Yes, Mr. Chair, that is correct. As Mr. Tremaine indicated, some slight adjustments of the location of a few other wells in the interior. But those six wells are the new well locations.
CHAIR ROZATOS: Okay. Thank you.
Commissioner Ampomah, did you have any questions on that?
COMMISSIONER AMPOMAH: Yeah, Mr. Chair.
So if you look, it sounds like the new wells are more on the exterior side. So can the parties explain how they, more or less, reach an agreement to site these new wells right at the exterior? Even during the hearing, OCD did have a concern that even the interior portion has not been fully delineated.
MR. MOELLENBERG: Mr. Chair, Commissioner, I

can explain that briefly. And if you have more technical questions, we do have Mr. Grahams, our consultant, online who could respond to that.

But mostly, Mr. Grahams took a look at where we were with the spacing of the perimeter wells and made some slight adjustments, in some cases moving wells slightly outward at locations where it would be expected to be fully outside of the plume and provide a clear delineation in that area that it's not affected.

In other cases, for example, in the southern portion, there's new 5 and new 6, which were intended to just provide better spacing. I think there was a well down there, it's not shown on the map proposed by Apache. That was TMW 25 that was more or less in between and perhaps a little to the south of those. So it was really just to improve the spacing of the perimeter delineation to make sure that the monitoring captures all of the potential areas where the plume might be or in the northern area, obviously, to space the up-gradient wells more appropriately.

COMMISSIONER AMPOMAH: So is it my understanding that, let's say assuming new 5 and then new 6, new 4 and new 3 and also the northern one, so once you drill these wells and then you sample and then you do not see any chloride in the analysis, then more or less shows that you've been able to delineate the boundaries of the plume?

Okay. Thank you, Mr. Chair, I do not have any further questions.

CHAIR ROZATOS: Mr Tremaine, you wanted to add on, correct?

MR. TREMAINE: I did just want to point out for the record that those are revised wells. But the green wells on the map do reflect that we retained -- so one of the questions was how are we delineating the interior and addressing OCD's concerns with the interior.

And so those are not represented in the yellow wells. Those are the green wells on map. And so the bulk of those wells from the order have been retained. So the interior is resolved by those.

And then, for instance, if you look up at the upper right-hand corner of the map that reflected as existing well TMW 13, the green TMW 33 from the order and the SB-1, Soil Boring 1, so in OCD's proposals and our discussions, we've previously proposed a groundwater monitoring well at SB-1, because we wanted to know what was up with that scarring at that location, right, on the lack of vegetation?

And conferring with the parties, the proposal is to, instead of relying on a new well there, rely on the two down-gradient wells in those locations, and put a soil boring that does not extend down to groundwater because we don't want to create a new conduit through potential contamination down to groundwater.

So we're doing kind of a combination platter there of the existing and new well, both down-gradient and the soil boring.

So I wanted to clarify that for the record, that those are -- from OCD's technical review, we believe that those locations are appropriate and the revision still captures what was represented in OCD's original ask in the order.

CHAIR ROZATOS: Okay. Commissioner Bloom, did you have any questions yourself?

COMMISSIONER BLOOM: No, Mr. Chair. I had the opportunity to review the materials prior to the meeting today, and I'm very comfortable with this. Thank you.

CHAIR ROZATOS: Commissioner Ampomah, any other questions?

COMMISSIONER AMPOMAH: No, Mr. Chair.
CHAIR ROZATOS: So I think we're all in agreement that we're comfortable with these changes. So we'll definitely get the order amended and written up and get it all out for everybody. So we'll do that.
Any questions from the parties?
Mr. Moellenberg? Mr. Tremaine?
MR. MOELLENBERG: Mr. Chair, no questions. Appreciate your consideration of the revision. And with this, Apache will not be filing an appeal.
CHAIR ROZATOS: Excellent. Thank you.
Mr. Tremaine.
MR. TREMAINE: Nothing further. Thank you, Mr. Chair, Commissioners.
COMMISSIONER BLOOM: Mr. Chair, just curious. Do we need to vote on this?
CHAIR ROZATOS: I think we actually do. I was going to kind of move on to that part, so I agree. So all those in favor for the amendment.
COMMISSIONER BLOOM: Mr. Chair, if you'd allow me, I would move to adopt --
CHAIR ROZATOS: All right. Please, can we move to adopt it?
COMMISSIONER AMPOMAH: And I second.

CHAIR ROZATOS: Excellent. Okay. Now, all in favor, say aye.
ALL MEMBERS: Aye.
CHAIR ROZATOS: Okay. So it's now officially approved. Thank you, Commissioner Bloom. I appreciate.
Excellent. Thank you to all the parties for that.
(Motion approved.)
CHAIR ROZATOS: We'll move on to our next case, which is the consolidated cases by Goodnight Midstream and Empire New Mexico. It's Case Numbers 24123, 23614 through 17, 23775, 24018 through 24020, and 24025. It is a continuation of an evidentiary hearing.
We have our hearing officer.
Commissioner Bloom, thank you. We appreciate it. And we'll get Mr. Lamkin on.
COMMISSIONER BLOOM: Thank you. And Mr. Lamkin is on his way up. Thank you. Have a good day. Thanks.
CHAIR ROZATOS: Thank you.
Mr. Harwood, we will transfer the hearing over to you.
HEARING OFFICER HARWOOD: Thank you,

Chairman Rozatos. Good morning, everybody.
I'm assuming, but I'll ask anyway that we do have the court reporter and we are on the record. Is that correct?
All right. Great.
We have what I understand is an agreed switch-up of witness order at this point. Empire, you're aware of this, right? You guys discussed it with Mr. Rankin?
MR. WEHMEYER: That's correct. Our understanding is that it will be Dr. Davidson, followed by Mr. Knights, followed by Mr. McBeath.
HEARING OFFICER HARWOOD: All right. That's my understanding as well.
Let me just remind everybody, put your phones on silent. We don't need to be rudely interpreted by any ducks this week.
So it looks to me like Dr. Davidson is here in person.
MR. RANKIN: Correct, Mr. Hearing Officer.
HEARING OFFICER HARWOOD: Doctor, if you'll raise your right hand.
MR. RANKIN: He's in the back. He'll make his way up to the stand now.
HEARING OFFICER HARWOOD: All right.

MR. RANKIN: And another point of order, Mr. Hearing Officer. Dr. Davidson, did have recent cataract surgery and has been having difficulty. So he's bought printouts of his portions of a slide presentation so it's easier for him to see, and perhaps for the commissioners as well.

HEARING OFFICER HARWOOD: Been there, done that, so I understand perfectly.

Good morning Dr. Davidson.

JAMES ALEXANDER DAVIDSON, Ph.D.,

having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Dr. Davidson, will you please state your name for the record.

A. James Alexander Davidson.

Q. And by whom are you employed and in what capacity?

A. Netherland, Sewell & Associates, senior technical advisor in petrophysics.

Q. Have you previously testified before the Oil Conservation Commission?

A. I have not.

Q. Can you please give a brief summary of your education.

A. BS, MS, Ph.D. in petroleum engineering. University of Texas for the MS and Ph.D.

Q. Is our resume attached to your written direct testimony and marked at Exhibit D-1?

A. Yes.

Q. Will you also please give us a brief summary of your work experience as a petroleum engineer and as a petrophysicist, in particular as it relates to your experience working in complex carbonate systems and your experience in and around the Central Basin Platform.

A. Well, I started about 45 years ago working for Arco Oil and Gas Company. But previous to that, while I was going to undergraduate school at Texas Tech, I worked part-time for what was at the time Amoco Oil and Gas Company. Subsequently went away, as did Arco.

But part-time work was involved with Levelland Slaughter Field. They were evaluating doing some coring, log analysis work, evaluating that field for potential CO2 recovery operations. That was during my undergraduate.

After I -- and I also worked in the summers for Amoco in some of their Permian Central Basin Platform waterfloods, where they were doing infield drilling, and also doing evaluations for CO2, potential CO2 flooding. And then that would have been in Henson Farms, North Cowden, South Cowden, those fields.

When I graduated, with a BS, I went to work for Arco, and my first job was in Midland, Texas, and I was assigned to the North Foster Unit, J.L. Johnson 8 units. And, again, Arco was doing the same thing as everybody else at the time, evaluating the waterfloods for potential CO2.

The reason for that was at that time, there was incentives. There were oil price controls at that time, in the early '80s, and there was incentives if you went to CO2 injection. As an EOR project, you got additional dollars for each barrel of oil. So all the majors at that time were evaluating their waterfloods, San Andres Grayburg waterfloods, for CO2. So that was my introduction to this type of work.

I worked for Arco for a year there, then was transferred to California. And there I worked several conventional waterfloods. And then moved to Indonesia, where I worked offshore Indonesia and was involved again with a large carbonate, the Bima Field, where we were doing an evaluation there as log decor and trying to figure out how to map dissolution precipitation fronts diagenetic that were affecting the performance of that field.

I left Arco and went back to graduate school at University of Texas and got a Ph.D. there. During that time, I worked periodically with the Bureau of Economic Geology. And at that time, the Bureau was doing an extensive study of the Grayburg San Andres as far as rock typing and developing petrophysical models that could be upscaled for reservoir simulation. It was a huge, interesting reservoir simulation in the Grayburg San Andres. And this would have been '90 to '98.

And that was the time that Jerry Lucia and Charlie Kerans were doing all the work on the outcrops out here in New Mexico and a bunch of them working in West Texas, where they were evaluating the different rock types and turning the rock types into reservoir simulations descriptions.

I didn't work directly with Jerry Lucia. I worked with one of his colleagues, Fred Wang. Jerry did the core work, the geology work, and Fred was charged with the doing the correlation of well logs to the core work. And they worked together to develop a pretty sophisticated model for a carbonate ramp environment.

After I left University of Texas, I went to work for Netherland, Sewell & Associates, been there about 26 years. And we do carbonates all over the world there. There I've worked some of the largest carbonates in the world, North Field, and Qatar, Taq Taq and Chemchemal in Iraq; worked large carbonate discovery up on the Guinea.

We -- from the time I joined Arco in 1998 until about 2019, we did Pemex reserves every year. And during that time, I worked every carbonate reservoir they had in Mexico and basically looked at every -- described and looked at every core from the carbonate fields in Mexico and the clastics, as well. I spent quite a bit of time down there in mosquito-infested core facilities, describing cores and building reservoirs models from there.

So that's a summary of my carbonate experience.

Q. Pretty extensive. Tell the Commission a little bit about what Netherland, Sewell & Associates is and what they do and what your role is with them.

A. We're reserve auditors, reserve consultants. The Security and Exchange Commission requires publicly owned companies to have an independent reserve estimate each year with their SEC filings, and we provide that service for publicly traded companies. We're the largest company that does that. We have more clients for SEC than any other of the major consulting companies.

The other thing we do is reserve certification, independent estimates for project financing for large projects. And, again, we work on a lot of the larger projects in the world. For example, the offshore Northwest Australia, Chance Gorgon. We reserve certification for the North Field, which is the giant LNG project in Qatar. We did the certification for the pipeline from Azerbaijan into Europe, which was pinned down by the reserves in the ACG Field.

The other thing we do is equities, when there's equity disputes. We've been involved in some of the largest equities in the world, the largest probably being Elk Hills National Petroleum Reserve equity dispute between the Department of Energy and Chevron. Our job is to provide independent reserve estimates for the purposes protecting capital, basically.

Q. Now, in this case in particular, Goodnight Midstream retained you for purposes of this case.

Will you explain what it was you were asked to do in this case.

A. We were asked to provide an independent petrophysical evaluation of the San Andres Grayburg interval, both inside the EMSU, from selected wells inside the EMSU, and from wells outside, some of the outside operated water disposal wells, for the purposes of basically determining or estimating oil in place -- or not oil in place, but to determine whether or not a residual oil zone existed and whether there were significant amounts of residual oil in the Lower San Andres where the disposal operations were going on.

The other thing that we were tasked to do was to identify potential flow barriers between the disposal zone in the lower part of the San Andres and the upper operations in the Upper San Andres and Grayburg, where Empire is operating.

Q. So, in other words, to look to see if you could identify any potential hydrocarbon reserves and also to evaluate whether or not there was a potential for a productive residual oil zone in that disposal zone where Goodnight is injecting; is that right?

A. That's correct.

Q. And have you then conducted a petrophysical study of the San Andres in and around the EMSU?

A. Yes, we have.

Q. Just at a high level, would you let the Commission know what it is that you did, what you looked at to come to your opinions?

A. Well, we looked at all the well logs, we looked at the core data. I did a significant deep dive into the petrophysics of the San Andres Grayburg and the literature. I had a lot of background from my work at the Bureau of Economic Geology on the type of work that had been done.

We drew all that information into our -- to build a petrophysical model to evaluate the potential of oil in place and the potential for barriers.

Q. And in the process of doing that, did you pursue independently your own independent investigation? You went and dug through data on your own and found --

A. Yeah. Again, I had quite a bit of experience. I was with the Bureau when the outcrop study at the Guadalupe Mountains was being carried out want. And the purpose of that study was to build a general model for a carbonate ramp environment that could be applied to any carbonate ramp, you know, anywhere in the world. So I was there when that work was being done.

We relied heavily on that study because it was the San Andres that they were studying, and specifically, they were studying the part of the San Andres that's in the -- that's associated with the disposal zone below the EMSU. So we relied heavily on that information.

At the time, we kind of had a faux pas, in a way. I was aware of the 679 core; we studied it extensively. There was also another core that was available for the RR Bell 4. Unfortunately, we discovered that there's two RR Bell 4s associated with the EMSU. One of them was drilled sometime in the late '40s, I believe, and one was drilled in the '80s.

We found the well that was drilled in the '40s, and it -- the log quality wasn't going to be sufficient for us to do anything. And there seemed to be a hundred-foot discrepancy in the strapping on the core. So we weren't quite sure where it was within the system, so we kind of used it for the purposes of defining porosity ranges and permeabilities, but we didn't really use that data significantly. We relied more heavily on the 679.

I became aware that the RR Bell was

drilled in the '80s and there was a full log sweep for it when we got the rebuttal from the Ops group. And we were able to go out and get that log. And we'll talk a little bit more about that later.

Q. So in addition to doing your own investigations, did you also review all the data and information that was provided to you by Empire and Goodnight?

A. Yes, we did.

Q. And have you prepared written direct rebuttal and surrebuttal testimony, exhibits and figures in the appendices that are attached to your materials that are marked as Exhibit D and then in your resume, Exhibit G-1, to provide your opinions and analyses?

A. Yes, I have.

Q. Were the exhibits and figures included in your direct, rebuttal and surrebuttal testimony prepared by your or under your directions and supervision?

A. Yes, they were.

Q. Any corrections or changes to the testimony figures or exhibits that were filed with the Commission?

A. No.

Q. Dr. Davidson, do you adopt the testimony and self-affirmed direct testimony, rebuttal testimony and your surrebuttal testimony that's marked as Exhibit D as your sworn testimony today?

A. I do.

MR. RANKIN: Mr. Hearing Officer, I would at this time tender Dr. Davidson as an expert witness in petroleum engineering and petrophysics.

HEARING OFFICER HARWOOD: Any objection, Empire?

MR. WEHMEYER: Without objection.

HEARING OFFICER HARWOOD: OCD?

MR. MOANDER: No objection.

HEARING OFFICER HARWOOD: Rice?

MR. BECK: No objection.

HEARING OFFICER HARWOOD: Pilot?

MR. SUAZO: No objection.

HEARING OFFICER HARWOOD: He'll be so recognized.

MR. RANKIN: Mr. Hearing Officer, I'd also move the admission into evidence of Dr. Davidson's direct testimony, his rebuttal testimony and surrebuttal testimony and attached exhibits, figures and appendices that are marked at Exhibit D and his resume as Exhibit D-1.

HEARING OFFICER HARWOOD: Empire, any objection?
MR. WEHMEYER: Without objection.
HEARING OFFICER HARWOOD: OCD?
MR. MOANDER: No objection.
HEARING OFFICER HARWOOD: Rice?
MR. BECK: No objection.
HEARING OFFICER HARWOOD: Pilot?
MR. SUAZO: No objection.
HEARING OFFICER HARWOOD: They will be admitted.
(Admitted: Goodnight Midstream Exhibits D and D-1.)
BY MR. RANKIN:
Q. Dr. Davidson, have you been present for or did you listen to the summary testimony, the cross-examination and redirect testimony provided by Empire's experts during the first and second week of testimony in this proceeding?
A. I did.
Q. And did you also hear Mr. McBeath's direct testimony and part of his cross-examination that has been conducted to date?
A. Yes, I did.
Q. Did you prepare summary slides reflecting

your up-to-date opinions, including any additional opinions based on observing that summary testimony, cross-examination and redirect testimony from Empire's witnesses during this proceeding?

A. I did.

MR. RANKIN: Mr. Hearing Officer, I'm going to share my screen so that Dr. Davidson can review with the Commission his opinions.

BY MR. RANKIN:

Q. Dr. Davidson, I know you have a hard time seeing it on the screen, but you've prepared some slides, and I'm going to put them up on the screen here, and I'm going to ask you just, if you would, Dr. Davidson to walk through so the Commission understands exactly what you think is most important about this case and other factors that, in your opinion, should be considered in assessment and analysis.

A. Okay. Ready to go?

Q. Yeah.

A. So first part is my interpretation summary. And basically I wanted to kind of start -- I'm going to be using some terms that are associated with a carbonate ramp environment and different rock types. We feel like it's very important to understand the petrophysical characteristics of the different rock types present in the petrophysical modeling process.

Basically what this is showing is a cartoon of a carbonate ramp environment. And I'll try to get through this pretty rapidly. In the high energy, where there's a lot of wave energy at the top of the system, that's where the coarser grained sediments, carbonate sediments, reside. And those are generally described as grainstones, relatively large grains, very little mud content.

You move down where the wave energy is a little bit lower and you get into what's called a grain dominated packstone. And what that is is coarse grains with some mud material, carbonate mud material. Mud meaning not clastic mud, but mud-sized particles, which is very small grain carbonate sediments. And they start mixing together.

You get a little deeper in the system and you get into something called the mud dominated packstone. And that's where the volume of mud exceeds the volume of the coarser grains. And then, when you get even deeper into the system, you get into something that's called the wackestone. And there, the mud grains almost totally dominate the grain system.

And then at the bottom of the system in the deep water, you usually have lime mud. And, again, this is mud in terms of grain size. Very, very small grain sizes.

And in the environment where the sea level is changing or there's subsidence and uplift, you can get these different -- this depositional system stacked on top of one another. So when you drill a well, sometimes you drill through several sequences that represent different piece of this carbonating ramp.

And typically what happens is as you move deeper in the system, you get higher gamma ray readings because gamma ray in this environment is dominated by uranium content, and uranium absorbs onto the grains. And the smaller the grain size the larger the surface area for the uranium to absorb upon. So the gamma ray goes up.

So the other thing that happens is in a shallow water environment, for example, where I'm showing the grainstones, you have high wave energy, and in that environment, uranium content is typically pretty low.

So we use the gamma ray curve very extensively to kind of tell us where we are in the depositional environment. It's basically an indicator of mud content. The grains get smaller, the permeability typically decreases the deeper you get in the ocean, the deeper you move into the ocean. And with the higher mud content, the grain size is smaller and the permeabilities typically go down and the reservoir quality goes down. So we're very cognizant of the different rock types when we're trying to do an evaluation in a carbonate ramp field.

Let's go to the next slide.

So this is -- first thing we have to do is get an understanding of what the core data is telling us. And one of the problems that you have with conventional core is, when you cut the core, you're cutting into reservoir pressure and then you're bringing it up to surface. And as the pressure is released, the gas expands in the oil, and some oil and water are expelled. And we have to be cognizant of that when we look at the surface oil and water saturations that are reported in the core reports.

The other thing that happens is, as the gas expands out of the oil, the volume of oil shrinks due to the loss of the gas, and that's the shrinkage. So we have bleeding and shrinkage.

And then the other thing that occurs in

a conventional reservoir is, when you're coring with water, oil is flushed from the near well bore area. However, in this situation, that's not the big of a problem because the core was drilled in a residual oil zone. So arguably, the oil is going to be relatively immobile, it's not going be to flushed. Now, we still have the bleeding, we still have the shrinkage, but we're probably not going to have much flushing.

Now, there's been another loss mechanism that's been discussed earlier in this hearing. I think it was referred to as super flushing. And the more correct term for that is stripping. And that has to do with the fact when you have a high pressure at the coring bit and low pressure in the formation, sometimes you can get high velocity water movement at the bit that can strip oil out of the rock due to very high viscous drag forces, due to the high pressure differentials.

However, we did an analysis on that and the permeabilities in the matrix at EMSU, at least in the 679 core and in the RR Bell core, were too low. It takes permeabilities in excess -- roughly a darcy or higher for stripping to occur, and we just don't have that much rock. Most of our rocks are in the 10s of millidarcies to 1 darcy range.

So the stripping, we did the modeling to check was it present. We came to the conclusion it wasn't. So we concentrated on the shrinkage and the bleeding.

And so originally, I used a little rule of thumb that was developed by Jake Rathmell out of the Arco Research Center for use when -- again, when I started in the industry, there was a big push to try to evaluate fields very rapidly for potential CO2. And our research department developed some simplified procedures that we could use to correct the core data so that we could, you know, evaluate in-place volumes and determine whether or not we potentially had a CO2 project that could follow a waterflood. So I used that little rule of thumb method.

And I got some pushback on that during my verbal testimony. It seemed the implication was it was too simplistic and that a more rigorous approach might be needed. So I went back and did the full rigorous evaluation.

What we did is we took data from where we had -- pressure core data from the Seminole San Andres and Maljamar Field up to the north. And we looked at the oil properties, gas content, initial gas content, gas content at minimum reservoir pressure, we looked at viscosities, we looked an oil gravities at those two locations.

And then we moved -- at those two locations, we actually had pressure core data, where we had a pretty good idea of what the shrinkage and the bleeding values actually were. And we actually had core measurements where those could be quantified. And we took that data and we moved it back to the conditions that exist in the EMSU.

And you have to realize that kind of as you move off the central part of the Central Basin Platform toward the edges, you go to the east or the west edges, the oil properties tend to degrade.

For example, EMSU up in the Grayburg, the gravity was on the order of 30, 31 degree API, whereas, at Seminole, it's 35 to 38 degree API. And so you have to take those changes into account.

The other thing you have to take into account is changes in the gravity resulting from going below the producing oil-water contact. And at Seminole they found that oil gravity went from roughly 35 down to about 27 degree API below the oil-water contact. And that's very common, but it has to be taken into account that the 679 core was taken below the producing oil-water contact.

And basically, when I went through the mathematics to kind of figure out what the gravity was that would be what you'd expect below the contact, it was about 26 degree, not the 31 degree that Grayburg oil -- original conditions above the contact was measured at.

The other thing that happens is the viscosity goes up, so we took the viscosity at Seminole and also the viscosity data at Maljamar. We corrected that back to the EMSU conditions, and what we found was that the viscosity that -- for example, the viscosity below the oil-water contact at EMSU was roughly three times the viscosity that they had observed below the oil-water contact in the Seminole.

And bleeding is directly proportionate -- and this is some work that was done by Jake Rathmell at the time I was working with Arco in the research company. Bleeding is directly proportional to the gas content, and we found that the gas content at -- the gas content depends on the amount the reservoir has been depleted prior to the initiation of the CO2.

And we had some pressure measurements that were available, MTD measurements, that kind of defined a range of potential reservoir pressures at the location of the 679 core, and we evaluated that whole range.

But long story short, the gas content of the oil below the oil-water contact at the EMSU was roughly maybe 60 percent of what it was below the oil-water contact in the Seminole, you know.

So the bleeding is directly proportional to the gas content, inversely proportional to the viscosity of the fluid. The higher the viscosity, the less bleeding you get; the higher the gas content, the more bleeding you get.

So we had to make all those corrections back to EMSU conditions, and we came up with a range -- so then there's also -- you have to do the B sub o calculations, which are directly proportional to gas content as well. So we went back and we took the original B sub o, we used the Grayburg B sub o, and then we corrected it to bottom hole conditions, considering a range of potential pressure drawdowns prior to the coring of that well.

And long story short, the final correction factor kind of varied. When we lumped all that stuff together, it varied from about 1.1 to about 1.25. And if we assume that there has been no pressure drop at all in the San Andres, in other words, it had never experienced any pressure drop, then that 1.25 became 1.3.

And the little Jake Rathmell rule of thumb gave me a correction factor of 1.22, which seems to fit pretty well within that 1.1 to 1.25 range. So we were pretty comfortable that we didn't need to make any changes to our original core corrections.

Go to the next slide.

Then the next thing to do was to identify the different rock types that were available in that 679 core. And basically what I did there was use a rock typing procedure that was developed by Jerry Lucia at the Bureau of Economic Geology. And it was -- the major data for that at the time -- that procedure has undergone an evolution with time, as Jerry learned more and more about San Andres and Grayburg.

But the interesting thing is that he developed an original version of that cross-plotting technique with the Lower San Andres at that outcrop, which is exactly where we're evaluating the core for the EMSU. So I was able to go back and use his cross-plotting technique to identify the different rock types that were present in the core. So we did that.

And then so now I've identified the grainstones, the packstones the grain dominated, you know, packstones, the mud dominated packstones and wackestones. And we were able to identify each of those in the core.

And then the next that you have to do, we don't have core in every well, so I have to be able to you identify, predict the different types of rock facies present using the oil log measurements. And we did that. Of course, we have well log measurements we can use. We used the gamma ray density, neutron porosity measurements. If we have sonic, which is great, that provides some very important data.

And the other thing that we brought to bear was a modeling process developed by George Asquith, out of Texas Tech University, where you basically calculate an estimate of what the porosity of the rock is from the shallow resistivity measurements. And then by comparing that resistivity based porosity estimate to the actual porosity, you can determine kind of whether you're in a uni-modal pore system or a multi-modal pore system. And that helps you in a buggy environment. And when you have something like a mud mixed with a grainstone, you have a multi-modal pore system.

So using that porosity, you can kind of start developing a model on differentiating, for example, between a grainstone and a grain dominated packstone and a mud dominated packstone. So we used that information.

The other thing that we used is the uranium content. You know, that tells us something about the depositional environment.

And then the other thing that we found that was very useful was looking at shallow, medium and deep resistivity measurements in evaluating the invasion characteristics. And we were able to see, by looking at the invasion characteristics, that the different rock types had different invasion characteristics into the formation. So we brought that to bear in the rock typing.

Now, the other thing that we used and didn't discuss here, but -- because most of the wells in the EMSU, at least the ones that we were given to evaluate, didn't have sonic measurements, which I found to be quite unusual. But that was the hand we were dealt.

Now, the wells that -- some of the wells we were given, the disposal wells outside the EMSU, did have sonic data. And Jerry Lucia built a very comprehensive model when you have sonic measurements to do rock typing based on looking at the volume of calculated bugs to the total porosity. And they had done quite a bit of work at the outcrop study where they were actually able to kind of tie what's called the BPR, the bug to total porosity ratio, to rock typing and permeability.

So we were able to adopt that model, and that gave us -- that was actually a pretty neat thing, because it gave us a way to do rock typing without having to look at all this invasion profile and all these other things. It's kind of an automatic. And it's a really nice model. The problem that we had with it, we can only apply it on wells that we weren't really interested in.

But, on the other hand, what we were able to do, because we had the highest confidence in the model that had the sonic measurements, we able to take our model that we developed without the sonic, run it through the wells where we had the sonic and see did we get the same type of distribution of facies, the same type of oil saturations, the same porosity.

So we went through a process where we iterated through that to ensure that our model was predictive in a situation where we didn't have sonic. And why is that important? It's because up in the area where the core was drilled, there wasn't that much -- there was bug porosity, but it wasn't as high as it is deep in that disposal zone.

When you get into the disposal zone, the bug porosity karsting stuff starts becoming very significant. And we were very concerned that our model be predictive when we got to very high bug porosities because we didn't have it in the core. So it was very important for us to have a model that we could take to that Lower San Andres and have decent predictions of oil volumes in the area where the bug porosity was higher.

We found that that -- that the model did match when we run what we call the no-sonic model in the wells where we had sonic and compare it to the sonic porosity water saturation, oil saturation calculations. They agreed very well. At that point, we felt like we had a predictive model.

Now, since that time, we've had the opportunity, particularly at Maljamar, where we have a sonic and -- sonic measurements, a pressure core where we have the highest confidence in the oil saturations and porosities, and we were able to run our sonic and no-sonic model on that well, and we got a really good match to the core measurement.

So at the end of the day, we felt very comfortable that our model was predictive in all environments.

Q. Now, the Maljamar well that you're referring to, that was the 522 well; is that correct?

A. Yes. No, it's not. 522 is the north well. 358 Maljamar I think is the one in the Maljamar Field.

Q. Thank you for correcting me.

And just so it's clear, you prepared two models, petrophysical models, one that employed the sonic data and another that followed the Jerry Lucia approach, correct?

A. They're both Jerry Lucia approaches. It's one of them works without sonic. It depends on a facies model. The other one is pretty much -- the Jerry Lucia model that employs the sonic is pretty much an automatic rock-typing model. As soon as you have the sonic measurements, you calculate the bug porosity ratio, you can pretty well -- it figures out the rock types for you and assigns the parameters that we can do the saturation calculations.

Q. Dr. Davidson, before we move off this slide, you heard some criticism of your approach from the petrophysicist from Ops Geologic criticizing that you did not evaluate or did not -- you excluded certain rock types from your assessment. Can you just address that?

A. Yeah. Our model, all rock types are available in every interval. And I can talk later on why that appears to be so to somebody who is not familiar with our modeling. But all rock types are available.

The Upper and Lower San Andres contain grainstones. The Upper and Lower San Andres and Grayburg contain wackestones, they contain mudstones. All rock types are present.

It's just that there's a change that occurs in the Lower San Andres where you change the depositional environment where some of the better quality rock types are less prevalent than are present up in the Grayburg Formation.

It appears that the Grayburg Formation was a pretty high energy environment its entire life. But in the Upper San Andres, to some extent, and what we call the Lower San Andres, and I'll show that distinction here shortly, it appears that it was more cyclical, where we have high energy, high frequency sequences. Sea level changes were happening pretty rapidly and rock types were changing pretty rapidly. And as a result, the relative amount, for example, the good quality grainstones is lower as you get deeper in the system. And I'll go over that shortly.

Q. Next slide.

A. This is important I think for several reasons, because what it's showing, this is the data from the outcrop study. And the outcrop study occurred at the Guadalupe Mountain outcrop to the west of the EMSU. I think it's maybe 60, 80, 100 miles away, but it's the San Andres section outcrops and they're able to actually get in.

When you do an outcrop study, you have to go in and kind of dig off the surface rock, get deep into the rock to get some of the things that are ruined by weather out of the way so you can actually kind of see what the reservoir rock looks like.

The point I wanted to make on here was, in the better quality rock, let's talk about that, the grainstones, the grain dominated packstones, those are generally considered to have the better quality. There's not that big of a porosity range. We're only talking maybe 10 to 14 percent for the better quality rocks. However, you see there's like an order or magnitude of more change in the permeability. It's incredibly important to be able to distinguish between the different types of rocks, and porosity is not the proper way to do it.

And the other interesting thing here, they found in general, until you got to the situation where you're actually developing karst, where it connected bug porosity, the presence of bugs -- when porosity increases, it's generally as a result of the presence of bugs. And the interesting thing here is, the presence of bugs doesn't necessarily mean -- higher porosity doesn't necessarily mean higher water quality. And that's a very important thing to consider.

Ultimately what happens is, the bugs -- bug are created in dissolution precipitation experiments. So you dissolve the material out of the rock to make a bug, but then at some point, that dissolved material gets reprecipitated and you actually wind up, in many cases, with lower permeability associated with the higher porosity.

Now, in the situation we'll talk about later, where we have huge throughput of meteoric fluids and H2S counterflow and all that, now we're creating connected bug networks and karst, and that's a whole different ball game.

But for the purposes of what we're talking about right now, I just wanted to point out that porosity, in and of itself, is not a good indicator of rock quality.

Q. You mentioned the term "bugs," and we've heard that throughout the testimony earlier. Will you just explain what a bug is, just at a high level?

A. Well, what happens, a lot of times you'll have, for example, a simple example, you'll have a critter shell, a shell from some sort of sea animal. And sometimes -- it's usually a limestone calcite-based thing. Ascitic fluid coming through, a high pH fluid coming through, will actually dissolve that shell out and leave a hole where the cast -- where the shell actually was, and then that water migrates through. And then later on, ultimately the water becomes super saturated and calcium carbonated and it reprecipitates out.

So a lot of times what you'll see, for example, you'll see bugs, and then there may be fractures nearby and water will migrate into those fractures and those fractures will become calcite filled as that calcium carbonate comes out of the solution. And sometimes it occludes porosities, you know, the pore throats, sometimes it occludes fractures.

But in general what they found at the outcrop, at least, was increased porosity due to increased bug content didn't necessarily mean increased permeability and increased reservoir problem.

Q. So the bugs are the voided space?

A. The big voids in there, yeah.

Q. Let's go to your next slide.

A. Here's kind of the -- we're kind of jumping ahead, but what I wanted to show here is situation -- I'm plotting what's called the resistivity index, which is just the deep resistivity, the RI. RI is the deep resistivity measurements divided by the resistivity of 100 percent water through the rock. And that's a typical thing that you do with any petrophysical model.

But what I'm showing here is the RI derived from the core measurements and the log measurements of deep resistivity versus the water saturation derived from the core measurements.

Now here, because -- we didn't use the water saturations from the core because, as I told you, what happens when you bring the core out is you expel water. And, for example, the cores for 679, for example, if you add the oil and the water up, you only come up with about 65, 66 percent of the pore space. So in a situation where you're below an oil-water contact, you would expect the core to be completely full of fluid. Well, it's not full of fluid anymore because when we brought it to surface, gas expanded and we expelled the water and we expelled oil.

I don't pay much attention to the water, but I know I can correct -- if I know enough about the permeability, the characteristics of the rock, characteristics of the oil, I can correct the oil saturations back to fairly decent representation of what they were back downhole.

So what we did here, the water saturations that are reported here are basically 1 minus the corrected oil saturation, because that would have been the water saturation we would have expected in a residual oil zone at bottom-hole conditions.

So then, you know, with the Archie models that have been used here, for example, original model I think that NuTech used, they used an Archie-like model, it's a Simandoux model. But in a situation where there's not much shale, and there's not much shale in the system, Simandoux basically will reduce to Archie. And I think Ops used an Archie-type model, as well.

And what you typically do is you plot the data up and then you find the data will typically fall on a slope on one of these cross-plots. And a plot on there, for example, the n equals 2 line, you see that almost all the core data falls above that. So n equals 2 is not a very decent representation.

And then I think Trentham and Melzer have recommended for this San Andres maybe somewhere in the 2.3 to 3.4 rang for n. So I plotted that line on here, what that line would look like. And you see again there's some data that falls on that line, but there's still quite a bit of data that falls to the right of the line. And, again, each rock type kind of falls on its own.

So what we wound up doing was using an alternate model that was developed by Schlumberger for oil wet reservoirs, and this is an oil wet reservoir, that uses a different equation in a parameter called a critical saturation. And the critical saturation lines you see here are those little curved lines that you see above the n equals 2 line, the little curved linear line.

What we wound up doing was taking each rock type, plotting each rock type independently on this plot, and then fitting one of those lines, what we call Sc lines, to each rock type. So you see for the grainstone, which is the G on this plot, the grainstone points we fit a line to it. And we went to the grain dominated packstone, we just plotted those points alone, and then we fit a curve to those lines. Then we did the mud dominated packstone. We did the Sc model to that one.

And that way, we built a model where if we could identify the rock type, we could actually use that rock type and the Sc value that represented that rock type in the equation in the bottom left here to calculate the water the saturation.

And the beauty of this is it takes all the data into account. And as long as we can reasonably identify the rock type, we can reasonably estimate what the water saturation is. That was the calibration procedure. We used this calibrated data in both the sonic and non-sonic models.

Q. Dr. Davidson, you mentioned that you don't pay much attention to the water saturation in the core. Just if you would, just briefly touch on why that is.

A. Well, it's hard --

MR. WEHMEYER: I do have a quasi objection point. So, Mr. McBeath was first, and that went over an hour and a half. This is a 30-slide-deck presentation. We're at Slide 6 and we're over 30 minutes in at Slide 6.

I think the longest Empire presentation was Mr. West at the end, maybe an hour and a half. You know, the comments that came from Friday, we have no problem with a little bit of leeway off of kind of the rough parameters set for direct, but this is going to be a two-and-half, three-hour direct examination at this pace. And this is not the way that Empire understood the proceedings were working procedurally.

HEARING OFFICER HARWOOD: Mr. Rankin.

MR. RANKIN: Well, Empire has 11 witnesses, we have fewer, three fewer. This is a very complex issue. I think I'll leave it to the Commission. We can curtail, I can ask Dr. Davidson to go up at a higher level.

I do think it's helpful for the Commission, and the Commission can tell us what their pleasure is, to understand exactly how Dr. Davidson did his analysis so it's understood.

I think the bottom line in this case is understanding whether and to what extent there is oil down here. And this analysis that Dr. Davidson is presenting explains that, how they came -- how he came to his determination.

A lot of this is in his written testimony, it's true. It's complex. And I can ask Dr. Davidson to, at a slightly higher level, to discuss it. But I leave it to the Commission. If this is helpful for them, then I'm happy to have Dr. Davidson continue at this level. Or if not, then we can go at a slightly higher level.

But I'll just say, I did not object at all to any of the time frames that Empire put forward with their witnesses. But they did have eleven and we just have eight, so it's not -- they had two separate sets of petrophysicists presenting, and we just have one.

MR. WEHMEYER: May I be hearted briefly in reply?

HEARING OFFICER HARWOOD: Sure.

MR. WEHMEYER: So the number of witnesses doesn't matter. Secondly, with respect to the examination here, I am hopeful for Mr. McBeath and Dr. Davidson, that given Mr. Rankin is spending all this time, that there wouldn't be any redirect because he's covered everything in detail.

Additionally, with respect to the witness statements, Dr. Davidson, I know you all are reading and preparing for three things, I'm not making fun here, he's quite loquacious. I think we have over 120 pages of direct witness testimony out of Dr. Davidson, including him being able to submit a surrebuttal for three rounds.

So, again, we're just trying to keep some reins on this because we're running out of the weeks that are allotted for the proceeding, and at this pace, we're going to be here a very, very long time.

HEARING OFFICER HARWOOD: Well, you know, there's some merit to the quasi objection. I mean, what I'm hearing from the witness is a lot of narrative. Now, I understand there needs to be some leeway because, frankly, it's all so technical that it's way over my head. But there is some merit to the objection.

I would ask that you make sure that the answers are responsive to the questions. And to the extent possible, avoid these long narrations.

MR. RANKIN: Sure. I understand. I'll work with Dr. Davidson to direct his testimony more succinctly.

HEARING OFFICER HARWOOD: Okay. Thank you. And to be fair to everybody, I mean, all of this is in the record already in written, sworn testimony. And these are high level people you're talking to. If you were explaining it to me, you could be here for a day. But you're not, you're explaining it to a highly sophisticated technical audience.

MR. RANKIN: Most of this is in the record, that's true, Mr. Hearing Officer. There's some elements that Dr. Davidson would like to address that are particularly responsive to the arguments and issues that have arisen. And I'll ask him to try to focus his recitals on those issues as we go forward.

HEARING OFFICER HARWOOD: That's fair enough. And I'll be listening for objections that the witness' answers are narrative.

MR. RANKIN: Thank you, Mr. Hearing Officer.

BY MR. RANKIN:

Q. So anything further on this particular slide, Dr. Davidson, in terms of how you came up with your petrophysical model to address each of the rock types.

A. No.

Q. If you would, just explain what this next slide shows and how it relates to our analysis with respect to the 679 core.

A. At the end of the day, the goal is to get a good match to the core data. So this is a match of our non-sonic model to the core measurements. In the right hand, you see the last two tracks to the right are porosity and oil saturation. And we feel like we did a fairly decent job of matching the core measurements.

In fact, if you take the oil saturation at each point and sum it up, our model over-predicted hydrocarbon pore volume by about 4 percent. But we felt pretty comfortable that we did a reasonable job matching the core measurements.

Hopefully that's short enough for everybody.

Q. Next slide here, Dr. Davidson, looking at the RR Bell 4, you also --

A. Okay. As I said, we didn't realize early on that the RR Bell had open hole well log measurements that were reasonable enough for us to use.

Ultimately, after we saw the Ops rebuttal, we found that there were raster images for the RR Bell logs. So we digitized the core section, ran our model blind against the core measurements, and this is the result.

And again, we felt that our model did a reasonable job for predicting the porosities and oil saturations from the RR Bell.

And, again, I hope that was fast enough for everybody.

Q. Next slide here, you're addressing the Maljamar core that you referred to briefly with me previously, the MCA 358. Explain that this shows with respect to your analysis regarding the corrected --

A. This was a -- yeah, this was an example -- again, this is one we got this data and evaluated late in the evaluation phase.

And Maljamar, the neat thing about that well, it was drilled and cored with a pressure core, which gives us the very best estimates of the oil saturations that can be corrected very accurately back to the reservoir conditions.

And what I'm showing here is the results from both of our models, the sonic model well where you can utilize the sonic data, and the model where we don't have the sonic data. And you see that both models, in my view at least, did a fairly decent job of matching the actual core oil saturation measurements.

Again, we just ran this model as it was

against this well and we ran both models of sonic, non-sonic. Now, it's not perfect, but we got a fairly decent match, at least to order of magnitude to the oil saturations for this well.

Q. If you would, just next slide here, explain to the Commission your understanding of what an ROZ is and how it applied to your assessment.

A. Well, we modeled this ROZ for the EMSU using this definition. It's oil remaining in a column below a trap that has been swept by vertical or horizontal flow to establish a shallower oil-water contact.

In our understanding, that's what 679 represented and that was what the ROZ in the EMSU is represented, where oil had been swept out of the interval below the current oil-water contact, and we were modeling it as a residual oil zone.

Now, the other thing that we're showing down here, this is data that BEG did, published for the Seminole Unit, where they had gone in and they -- for each rock type that I described, they kind of described what a residual saturation would look like.

You know, for example, if a well had -- or an interval had originally been full of oil and had been swept, what kind of residual oil would you expect? And looking at that, it says like, well, we would expect to see maybe 25 to 40 saturation units of oil in a residual oil zone. So what's kind of what we would be looking for.

Q. Just so it's clear, this is the basis for your assessment about whether or not or to what extent the disposal zone that Goodnight is injecting into would qualify as a potential residual oil zone?

A. Yes. And we'll a little bit more about the profiles here shortly. Again, I'm trying to speed up as best I can.

Q. So this next slide here, I think, goes further into this analysis. And you got it up on your paper here. Explain what this shows and why this is, in your opinion, critical to your assessment of the ROZ in the EMSU.

A. What we're showing here is the 746 well. This is our interpretation of the 746 well. To the right, I'm showing a well log from the Seminole San Andres Unit. And unfortunately, Hess decided they'd hold the cored well and the core information for Seminole as being confidential. However, we were able to find a well that was drilled as part of the ROZ development plan from Seminole.

So again, we went in and just ran our model blind against that well. And what you see there on the right-hand side is the Seminole well. And on the right track is the oil saturations.

And interestingly enough, we were able to duplicate -- down there, there's an MPZ which had been CO2 flooded for about 40 years. And you see the residual oil saturations there, oil saturations, on the order of 20 percent. You get down below the main production zone in what they classified as the ROZ, and we have oil saturations.

And, again, if you look at there, we kind of have a wall that's relatively flat, about 40, 45 percent. So we see the residuals kind of like what we would expect to see based on what we got out of the BEG for what the residual saturations would be.

So if we move to the left, we see the results from our calculations for 746. Why is 746 important? It's because it goes all the way through from the Grayburg all the way to the Glorieta. So we're going through the disposal zone in this well. And what you see is, in the Grayburg area and what you guys would call the Upper -- or we would call the Upper San Andres, does have what appears to be something that approaches what an ROZ would look like. It looks very similar to the ROZ over in the Seminole San Andres.

However, we get below that, you see there's a little bit of oil that shows up in the disposal zone in the interval below that. But the point is, the profiles just aren't the same. You get little wisps here and there and there's a hundred feet between them. Yes, there's little bits of oil down in that disposal zone. We think those are probably more likely paleo migration pathways, not an ROZ.

MR. WEHMEYER: Objection. Narrative.

MR. RANKIN: I've allowed Mr. Hardy to testify with her witnesses on direct.

I've asked him to explain why this is critical to his analysis and he's explaining it.

HEARING OFFICER HARWOOD: Overruled.

A. I'll try to make this as short as possible. We think the disposal zone predominantly consists of abandoned paleo migration paths. We think that the target, if there is one for CO2 injection exists in the Grayburg, and maybe the upper part of the San Andres, above what I call the gamma ray marker there, that very high gamma ray below where the high oil saturations are.

The other thing I wanted to point out on this slide, it's very important if we're moving west to east, and the top of the San Andres goes -- even using Mr. Wehmeyer's definition of how to pick the top of the San Andres, we go are from 400 feet down to 1800 feet for the top of the San Andres. So I'm just pointing out that going west to east, that the San Andres is downdipping.

Q. Before we move off this, Dr. Davidson, you explained that this profile in the EMSU 746 is indicative to you of a potential for a migratory pathway as compared to the profile you're seeing in the Seminole San Andres Unit well.

Can you tell the Commission why it is that you believe that this profile in the EMSU 746 within the disposal zone indicated here is more indicative of an oil migratory pathway rather than a zone that has been previously saturated with oil?

A. Because the oil saturations, when we can't calculate them to be present, are generally under 20 percent. And the oil that does show up, where we do have oil saturation, tends to be in the grainstones.

And what happens when oil migrates, it migrates through the best quality rock. And then all rock has some level of high permeability pathways at least partway, so oil, when it's migrating, small saturations can get into some of the poorer quality rock. But the higher soil saturations tend reside in the best quality rock.

And you never really build a trap in a migration path. And then if there's subsequent fluid flushing, the intervals that have very low saturation, say sub 20, the saturation doesn't change much. But the saturation -- you do wind up with a residual in the better quality rock and you don't get that nice, flat profile of high residual saturations that you see in the EMSU 746 up in the Grayburg and the SSAU well down in the San Andres. It's just a different profile. The saturation profile is just different.

Now we're going to talk about Tall Cotton. I've heard the interval below the oil-water contact in the Grayburg in EMSU described as both a greenfield ROZ and a brownfield ROZ. So I don't know which one that Empire actually believes it is.

But I went to look for what -- you know, assuming that Seminole is defined as a brownfield ROZ, where you have a trap below an existing oil column, Tall Cotton was described as a greenfield ROZ, where you have an ROZ that's not associated with a trap. So I wanted to look at what does the profile of an ROZ look like in a greenfield.

So we can go to the next slide.

And this is -- again, we ran our model

blind against the Tall Cotton. Unfortunately, Kinder Morgan, like Hess, held the core data and the log data for the cored well confidential, so we weren't able to get that. But I was able to find one of the development wells for Tall Cotton, and we ran our model there.

And, again, you can see that we have that kind of a flat 40 percent front for a hundred feet or more, where, you know -- it defines what I would consider an expected profile for a residual oil zone. Again, 20 to 40 percent residual saturations based on kind of found they found at the BEG.

Go to the next slide.

And this is the -- out of I think Mr. Melzer's or Dr. Trentham's paper where they're showing core data in an ROZ. This may be Seminole, it may be Goldsmith. I don't know for sure. But what they're showing again is a 20 to 40 percent oil saturation range through the ROZ.

To the left here is the core data from -- these are the corrected core points for the EMSU 679. And we're kind of not seeing that same kind of profile. We have a few feet there that kind of get up into the 40 percent range, 40, 50 percent range. But it just doesn't look to me like an ROZ.

However, it doesn't matter what I think. Empire wants to go and flood this, that's their prerogative. My argument is that what's going on deeper in the San Andres, below what I call the high gamma ray marker, the injections on there aren't going to affect their operations up in the shallow part of the ROZ.

Q. Just to be clear, Dr. Davidson, you referenced this chart on the left-hand side of your exhibit. Here it shows the corrected core values for the 679 and the EMSU well. Those are the core corrections based on your analysis, correct?

A. Yes, sir.

Q. What were the core corrections that you came up with for the EMSU 679?

A. Well, at the end of the day, the correction factor was about 1.22. For the pressure range present, it could vary between 1.1 and 1.3.

Q. Okay. Thank you. This next slide here, just explain -- you mentioned this previously as you were discussing your rock typing in understanding the system here. Explain how you determined how this gamma ray plot helped you evaluate and determine rock typing in your analysis for the EMSU.

A. Well, basically, once you do this for a while -- and it's important to realize that the gamma ray here is associated predominantly by uranium. There's not a whole lot of clay minerals in this rock that affect the gamma ray. So what we're actually seeing is variations in uranium. And like I said, uranium deposits based on surface area and wave energy.

Up at the top, above what I call the gamma ray marker, you see the gamma ray baseline is pretty low, those are the grainstones. Those are the high -- that's a high energy environment. And you notice above that high gamma ray marker, the rock is predominantly deposited in a high energy environment. That's the Upper San Andres Grayburg interval that we're talking about. Then you get what I call the high gamma ray marker.

Below that, you see there's a discernible shift to the right of minimum gamma ray measurements. And that's indicating higher surface area, which is indicating higher mud content. And when you have higher mud content, that's indicating poor reservoir rock quality.

So what we did is we found -- what we found is a gamma ray level above the baseline that would return the proper grainstone interpretation up in the Grayburg. Then we used that shifted gamma ray baseline to identify the grainstones below that high gamma ray marker.

So we do have grainstones in that deeper section, but what it's telling me is, as we move deeper in that section, I'm getting higher and higher mud content, meaning the reservoir quality, as we get deeper in the section, is deteriorating.

Now, what you have down there, below that high gamma ray marker, is a little spiky interval. And then there's an interval where the gamma ray kind of settles down, maybe about 4275 and down, and that's the interval where we'll see the karsting in the lower San Andres. We'll talk a bit more about that.

But basically, we go from an interval above that marker that's predominantly high energy to an interval below where we have high frequency sequences and we're getting lower and lower energy deposition. And, ultimately, we get into where we're actually starting to see deep water deposition, more mudstone, wackestone type deposition. That would be the poorest reservoir quality.

HEARING OFFICER HARWOOD: Mr. Rankin, would this be a good time to take a mid-morning break?

It's 10:31.

MR. RANKIN: I think that's just fine, Mr. Hearing Officer. We'll take a mid-morning break.

HEARING OFFICER HARWOOD: Let's be back at 10:45. Thanks.

(Recess held from 10:31 to 10:44 a.m.)

HEARING OFFICER HARWOOD: All right, Mr. Rankin.

MR. RANKIN: Thank you, Mr. Hearing Officer. I think we're on Slide Number 16 of Dr. Davidson's presentation, summary of his testimony.

BY MR. RANKIN:

Q. Dr. Davidson, the next slide, Number 16, would you explain how this slide reflects your analysis regarding the presence of anhydrites through the Lower San Andres that you analyzed?

A. Basically, we identified what I've called a high gamma ray marker. As I stated previously, what we see just below that marker, there's a marked shift in the minimum gamma ray values above the -- that are present up in the Grayburg.

Then what you see in the gamma ray track are very spiky gamma rays, and those gamma ray spikes typically correspond to low porosity intervals and, many times, higher resistivity intervals.

And we interpret those to be bedded anhydrites that are associated with a very high frequency depositional environment where we're basically probably prograding out into the ocean. We're moving from maybe a ramp crest to maybe the outer ramp. We're still getting some good quality rock being deposited. But then when the sea level falls, we get evaporites forming on the exposed rock. And when you evaporate sea water, you concentrate uranium. So the little gamma ray spikes you see below there are where we've concentrated uranium.

And then if you go to the right track, I'm color blind, but I think the color is purple, we've kind of identified the anhydrite intervals, or intervals with elevated anhydrite, as being purple.

And then the other thing we did is we want back to make sure that we had this right. We went back and used a cross-plotting technique that Jerry Lucia developed to identify anhydrites that hadn't been altered by any kind of diagenesis.

So a bedded anhydrite wouldn't be altered by diagenesis. And we would expect embedded anhydrite, we'd expect to see elevated gamma ray, we'd expect it to be unaltered and we expect to see an elevated presence of anhydrite.

So basically, that interval below what I call the high gamma ray marker consists of a high frequency sequence where there were multiple sea level changes. And we actually did have fairly good quality rock deposited because we're in a relatively high energy environment. But then they're capped by these intervals where the rock gets elevated above sea level and we're able to create some evaporites and create laminated bedded anhydrites. Now, these bedded anhydrites will be very good barriers.

Q. Dr. Davidson, were you able to corroborate your interpretation of these anhydrites with literature?

A. Yeah. And actually, Dr. Trentham describes this process as being part of the upper part of the Lower San Andres, this high frequency depositional environment, with the capping of evaporites at the top of each sequence. So I'm not the only person that identified this. Dr. Trentham described this depositional environment in the upper part of the Lower San Andres as well.

And I'm defining the Lower San Andres. I'm not a geologist, and I don't care to become one, to be honest with you. But the -- I'm defining the Lower San Andres as the San Andres interval below what

I call the high gamma ray marker.

Q. This next slide here, Dr. Davidson, goes into some detail about your analysis of these anhydrites. If you would, explain what this shows and how it reflect your analysis and determination of the existence of these anhydrites across the EMSU area.

A. So we had a -- I had a relatively limited data set and I didn't -- a lot of the logs that I wanted to have access to, we couldn't get in public available sites like Drilling Info and OCG and what -- OCD.

But what I was able to do, after we got the Ops rebuttal, they had access to whole lot more well logs than I did, and so we were able to get some well logs that penetrated through the Grayburg and a good part of what I call the Lower San Andres. And we war able to do mineralogy interpretations on those. And then I also went through the cross-plotting technique that Jerry Lucia developed, to identify the bedded anhydrites.

And what I found was, there's an interval -- and, again, the top line there on that yellow shaded area, I connect the dots between what I call the high gamma ray marker. And then below that, if you see the little flags next to the depth track, those were the intervals where we identified the bedded anhydrites.

And this is I believe a northwest-southeast cross-section through the EMSU, and you can see that there's an interval of bedded anhydrites that exist all the way across the field. And in my opinion at least, these would provide -- and, again, the majority of the injection, as I understand it, in the disposal wells are occurring below this interval that I've highlighted in the yellow there.

So in my view, the injection interval is isolated from the Upper San Andres above what I call the high gamma ray marker by several layers of bedded anhydrites.

The other thing on here that you can see is the porosity associated below that marker is quite a bit higher, indicating quite a bit of dissolution has occurred. And that's probably as a result of the meteoric water and the H2S migration that Dr. Lindsay and Dr. Trentham and Melzer have hypothesized.

Q. So I think the next series of slides, Dr. Davidson, specifically go to items that are identified in your rebuttal testimony in responding to NuTech specifically and I believe also Ops Geologic.

If you would, just explain what this

slide shows. I think it's information from Dr. Melzer and Dr. Trentham's assessment of ROZs. Explain how this relates to your rebuttal and what you have to say, your critique and response to Empire's petrophysical analysis.

A. Again, this is going to be my critique of Trentham and Melzer as well. They published kind of what they call a "Cookbook" of how to identify ROZs. And this is based on I think either four or eight counties, and they kind of defined m and n values for the Archie model. They defined water resistivities used and kind of tell you: Where am I on the Central Basin Platform, and after I know my location, how should I do the petrophysical calculation?

And in my opinion, and it's used in the Archie model -- and I'm going to talk in a few minutes about why the Archie model in any of its -- any way that it's presented is not the right type of model to use for this environment. But I think what -- the thing that bothers me is I can apply this Cookbook approach and I can find an ROZ almost anywhere, but the disturbing thing is, I almost always overestimate the amount of oil that's in place in the ROZ that I think I found.

Let's go to the next slide.

Q. This I think shows a core interpretation that you conducted on the 679. Explain what this has to do with your critique of the Trentham models.

A. And, again, what I've done here is I've shown, I believe, our -- I can't see very well, but I believe our interpretation is on there, and I've shown the oil saturations.

But then what I've done is I've displayed Dr. Trentham's model using the salinity that he said I should use. I think I used the Gaines County and we're in Lea County. So we're right across the border. But I used the model that he suggested in this Cookbook, in he and Melzer's Cookbook, and you see that it predicts a pretty constant oil saturation in the 60 percent oil all the way through the interval and doesn't match the core well at all.

Then the other model, I said, well, let's give them the benefit of the doubt, and we did not use the salinity that he pointed out in his Cookbook, but used the actual salinity that we knew to be present. And we see it does a little bit better job, but it still over-predicts the amount of oil in the ROZ. And my concern is this type of analysis may get people overly excited about their potential.

Let's go to the next slide.

Q. Just for clarity of the record, this slide is 20. And the two far right tracks are your application of the Trentham models to the core data, correct?
A. Correct.
Q. And the first -- the second from the right is the one where you applied -- from the Cookbook?
A. Right.
Q. And then the farthest to the right is the one where you applied the --
A. The correct Rw.
Q. Right. And the core data is in purple, right?
A. Yes.
Q. Next slide here is your analysis or assessment of I think NuTech's revised analysis relative to what you have done. Can you explain what your critique analysis is of NuTech's revised approach and how it relates to your analysis?
A. I've shown the original -- we didn't have curves for the original. The original was m equal -- n equals 2, which basically resulted in the overestimation of oil saturation all the way through the interval.
We were given, in October or November, a

revised NuTech analysis. And that one, we talked about that quite a bit during the testimony of Mr. Dillewyn. But that model was calibrated to the water saturations from the core. And I've got the core water saturations in that far right track. I think they're blue. And you see how they did a fairly decent job of matching to the core water saturations.

The problem is, the core water saturation don't represent the oil -- are not representative of what the oil saturations would be in reservoir conditions. And what I've shown, I believe it's green, are the corrected oil saturations. And you see that even the revised model overestimates the oil saturations all the way through the interval.

And we were told that, well, maybe we should look at the original model as a high side and the revised model as a low side and that develops a range that we would consider, so therefore, we've considered uncertainty in the petrophysical model.

I would argue that it's calibrated to the water saturation, which is the wrong thing to calibrate to. And both what they would consider the low side and high side overestimate the amount of oil in place in that 679 core.

Q. Next slide here. I think you do the same thing with the Ops Geologic analysis. Explain your critique of the Ops Geologic petrophysical analysis relative to what you have prepared in your analysis.

A. And here -- and we'll talk a little bit more about Ops. But the thing I wanted to point out here, what I plotted here are our estimates of the corrected core measurements. And what I would argue here is that both the Ops low side and the high side more often than not overestimate the amount of oil present through that interval.

Now, part of the reason that they gave for that was that they were trying to account for oil that was lost by the super flushing that we talked about, the stripping and super flushing. They said, "We're going to match as best we can to the data, but we're going to be a little optimistic to account for the fact that there was super flushing or stripping going on."

And, again, our analysis indicates that the pressure differentials at the bit weren't high enough for the permeabilities present for the super flushing or stripping to occur.

And, again, if you go back and do kind of what we did, we went back and looked at the hydrocarbon pore volume associated with each core point. And our model predicted that hydrocarbon pore volume within 4 percent.

The Ops model, their low side case, they said, "Well, in the low side case, we used the raw core data without any correction."

Well, even if we use our corrected core measurements, their low side is 30 percent higher than the corrected core measurements as far as the in-place volume, and 87 percent higher than the corrected saturation for the upside case.

So my argument is, the low side and high side on the Ops are still optimistic compared to what the core data -- the actual core measurements say that the presence of oil is. And in a minute I'll kind of show why that may have happened.

Q. So just to be clear, this is Slide 22, the second track from the right is NSAI, your analysis, showing the core data plotted in purple, with your model in the dash blue, correct?

A. Correct.

Q. And then on far right track, the blue solid line is Ops Geologic's low side analysis?

A. I can't tell the color, but it's the lower of the two.

Q. Okay. And then the higher side, on the right, is the red, and that's Ops Geologic's high side interpretation, correct?

A. Correct.

Q. And then same thing, you've got the corrected core saturations on the same plot?

A. And my conclusion here is, while there was a range established with the Ops model, it seems to violate the core measurements. And, again, you know, I was criticized earlier on for not having a range. So what I -- we went back and looked at -- Ops established the precedent of: Well, we're going to look at the corrected core, the range of uncertainty in the core measurements as the uncertainty in the petrophysics. And then they said, "Well, we're going to model our low side to uncorrected or high side to maybe an optimistically or slightly optimistically corrected core measurement."

Well, if I do that with ours, our correction factor for the core range from 1.1 to 1.3, and if I look at that in terms of uncertainty, that's about a plus or minus 10 percent uncertainty on each core saturation, that gives you a standard deviation of about .31, if you're interested in statistics.

But the point is, if you want to look at the uncertainty in our petrophysical model, take the saturation calculations and vary them by plus or minus 10 percent, and that would be a reasonable uncertainty range based on the uncertainty that we see in the core measurements.

Q. Thank you. Next plot, I think you do something similar again and look at a core that Ops Geologic had evaluated. Explain how this assessment of your model against the GSAU 522 well reflects your analysis as to your petrophysical approach.

A. Again, I won't belabor this one too long. There was a -- some early concern about the fact this 522 well indicated very high oil saturations in the San Andres, up to 60 and 70 percent, in an interval that arguably has been waterflooded. And that was put forth as evidence that hey, there's high oil saturations in the San Andres in the waterflooded intervals. We went back and looked at the data and found that oil has been added to the drilling mud just prior to the coring operations.

And I won't go into it in great detail now. It's in my testimony. We identified an interval where we think maybe some spontaneous inhibition may have occurred at the lower part of the core. And at high part of the core, there may have been mobile oil present. I think there was some testing done that indicated some mobile oil present in that green perforated interval in the depth track.

And basically, we took our model -- we didn't have this data early on. We had some electromagnetic propagation tool data. And we came to the conclusion, based on analysis of that data, with the Ops rebuttal we were able to get the actual open hole log curves for this, which I didn't have at rebuttal time. Again, we ran our model in the blind test and we were able to pretty much reproduce the conclusions that we had drawn from the analysis of the electromagnetic propagation tool in this well.

And basically, we concluded that oil contamination was the reason for the high saturations, not that they were actually there from the beginning.

Q. Thank you. This next slide here I think goes into more detail, I'm back onto the EMSU 660, and evaluates NuTech's revised analysis relative to some of the well tests that were conducted.

If you would just explain what this slide shows and how it relates to your critique of NuTech's analysis.

A. This argument can go with either the original NuTech or the revised NuTech, because up in the Grayburg, they're the same model. We've talked about this before in some of our previous testimony -- previous cross. This well is predicting the NuTech 60 percent oil saturations and above up in the Grayburg and upper part of San Andres in the intervals that tested basically very high water cuts. And we wouldn't expect the high water cuts, you know, 93 percent plus cuts in intervals that were 60 to 80 percent water saturation.

And I'll tell you that a conventional model, in the shallow part we would be running 2 and 2, Archie with 2 and 2, that's been demonstrated that that just flat doesn't work below producing oil-water contact. I discovered the hard way when I went to work for Arco. Jerry Lucia produced a bunch of documents showing that using Archie at almost any constant m and n value generally results in the overestimating the oil saturations.

So I think the NuTech model -- you know, they were moving in the right direction at NuTech, because they were going from a constant m and n to a variable m and n, which is the right direction in trying to tie it as best they could to facies. The problem is, they calibrated to the water saturation rather than the oil saturation.

And, again, we look at the actual

physical measurements, which is the produced oil. It just doesn't seem to match with our higher oil saturation from the modeling.

Go to the next slide.

Q. This next one, I think, again, you're looking at a mud log for the 746 well, and you're looking, in this case, at the Ops Geologic high and low assessments.

Explain how your interpretation or assessment of the Ops Geologic petrophysical analysis conflicts with what your understanding is of the mud log data.

A. And we're going to talk a little bit about why -- and by the way, I'm nearly done for all you all that are watching their watch.

The Ops model, interestingly enough, calculates very high oil saturations and very low porosity rock. And the reason for that is, more often than not, when you get low porosity rock, you get less than 5 percent porosity. A lot of those pores aren't talking to one another anymore. They become occluded with cement materials, pressure solution, which is, you know, the overburdened pressure at the grain-to-grain contacts, basically melting the grains and causing precipitation -- dissolution prescription reactions that could occlude the pores so one pore is not communicating with the other. It's a very typical problem in low porosity carbonates.

So what you see is, you get low porosity because it can't conduct electricity very well anymore. The resistivities are elevated. And if you just use an Archie model, regardless of whether it's variable m and n or any type of model, you can calculate the presence of oil where there isn't any.

And what I was trying to point out here is we're going down to an interval that's a low porosity rock, and I happen to have the mud log and I show the mud log through that interval shows absolutely no oil staining, no fluorescence, no anything. Yet, we're getting 60 to 80 percent oil saturation with the Ops model. And I'll show you in a minute why that these occurring.

But at one point, we scratched our head, you know, how can we come up with oil where the mud logs are showing nothing is there? And particularly in a situation where we have oil wet rock. This is oil wet rock, and in oil wet rock, oil is going to coat the surfaces of the carbonate grains, so you'd expect to see something on the mud log. And the fact that there's no shows of any kind -- the other giveaway is that your C-1 is at background level. So there was never any hydrocarbon there.

So, you know, what you're seeing there is a low side and high side from the Ops model in an interval that doesn't contain any hydrocarbon that's -- where they're counting that hydrocarbon in their oil-in-place estimates. And, again, this well tested, you know, zero oil.

Q. Next slide. I think another kind of similar analysis showing mug log relative to what Ops Geologic had identified as having high levels.

A. Yes, and I may have gotten these slides just backgrounds from one another. But it's the same thing. We're seeing oil saturation in an interval that produced very little to no oil at all in a low porosity rock.

Q. Next slide here is your --

A. This is the back one. Which way are we going? We went the wrong way.

Q. I skipped a slide, Dr. Davidson. I apologize. This next one here is the EMSU 746 mud log showing the Lower San Andres. If you would just explain how -- and this shows your analysis.

A. This shows our analysis. And granted, in that same interval, we calculated a little bit of oil in place. And I didn't put any limiters in to say, you know, if the porosity gets below a certain level, don't calculate oil anymore. And we actually calculated a little bit of oil in there, as well.

So, you know, this is kind of like the pot calling the kettle black, I'm saying that Ops kind of fouled up. Well, you know, to be honest, we calculate a little bit of oil there, too.

But rather than eliminate it, we left it there because we don't know for sure and we don't have mud logs in all the wells. So in order not to be overly pessimistic, I didn't say if the porosity gets to 5 percent, set oil saturation to zero. We just let it be what it was.

Q. In this particular slide, your interpretation, your petrophysical interpretation is the second track from the right, correct?

A. Yes.

Q. And I think you also show the farthest right track, you show NuTech's original and revised analysis?

A. Yes, in that one there.

Q. Okay.

A. Everybody is calculating oil in that interval.

Q. Okay.
A. I'm as guilty as everybody else.
Q. Very good. I think your point here, though, Dr. Davidson, correct me if I'm wrong, is that the saturations that are being calculated by both NuTech and Ops Geologic don't -- are not reflected in the mud logs, correct?
A. That's correct.
Q. Okay. Next one is the Meyer B 4-34, and I think you're showing your interpretation and the Ops Geologic interpretation. And I think you had a comment here about floating oil. Explain --
A. Well, what that --
Q. Explain that this shows and why their analysis doesn't jibe with what you understand the reality to be here.
A. And what we're seeing here, again, it's an interval where we have low porosity, and we're calculating reasonably high oil saturations in a portion of the rock that has low porosity. Then you go around that, what I'm calling the floating oil above and below, and you get elevated porosity values with water saturations at 100 percent.
And, you know, at one point, I think they stated they hypothesized that a residual oil zone

could reside all the way from the Glorieta up into the Upper San Andres.

And I'm having trouble with the physics of oil only existing in the very poor quality rock and being completely flushed out with no residual at all in the better quality rock. It certainly doesn't seem to fit the data that we have on -- if that interval had -- thea higher porosity interval had been full of oil and had been swept away, we'd at least expect to see residuals in the 20 to 40 percent range in that higher porosity interval, and we're not.

So I think this is an artifact of the way that they chose their m and n values. And I think I'm going to show that in just a second.

Q. Now, this next slide I think goes into that analysis where you've got a correlation. Explain what what this shows and how, in your opinion, it reflects that Ops Geologic's petrophysical analysis is flawed.

A. So what we did is we went back and we took the core measurements and I followed the procedure that Ops said that they followed. We took the core measurements. We corrected the saturations for each core point used in the resistivity values. We calculated using the Archie model what the m and n values would be. And I believe this -- hang on. I can't see. The Archie saturation. So this is N.

So if I took each core point with the resistivity measurements, the porosity, what we knew the formation water salinity was, and I calculated what would the N value be for that core point, and then we plotted it as a function of our corrected oil saturation, what turned into water saturation, so 1 minus oil saturation to get the Sw, and you see indeed there is a trend there.

But you see there's quite a bit of variability in the n values as a function of porosity. For example, you know, in a 5 percent porosity, I could have a couple of orders, two to three orders of magnitude variation in the n value for a given porosity.

Now, the other thing we did is we took the 746 data and we backed out what the -- what Ops did was, as a function of porosity, they calculated what an n value would be. And then they applied an m and n -- I think a constant m and then variable n value using Archie's model to calculate the saturation as a function of porosity.

And that line there represents the n value they would have selected for each porosity point, and you see it ignores probably 80 percent of the measurements that were in the core. The core had intervals which would have calculated much higher n values that were used in final model.

And I think that's why we're getting these floating oils and the 60 percent oil when you have 5 percent porosity, because the way it's designed, let's go to the next slide, and it's colored such that the best quality rock, the lowest -- highest oil saturations to the lowest water saturations I think are the green colors, and it's all along that leading edge.

So what they've done is, by choosing the correlation along the front end of that data, they've made every possible porosity return the highest possible oil saturation. And I think that's why their model is overestimating in the core generally leads to overestimation of the oil saturation in a lot of the points. And in the Lower San Andres when we get the lower porosity intervals, it's putting oil in the low saturation rock.

So, again, I think there may be an implicit bias based on the way that they modeled -- the Archie model they selected and the way they chose to select their variable n value.

Q. Thank you, Dr. Davidson. I think that's your last slide. A few questions to sum up your opinions.

Dr. Davidson, what's your opinion about whether Goodnight's disposal zone is a residual oil zone?

A. The disposal zone I don't believe is. There's several reasons for that. Predominantly because -- there's going to be oil in there in migration paths. It literally -- probably billions of barrels of oil have flowed through the San Andres to accumulate up into the Central Basin Platform over geologic time. There's going to be migration paths all through the San Andres.

However, when I look at the profiles, that's why we're talking so much about profiles, I don't the profile of an ROZ anywhere below that high gamma ray marker. And where we reduce the oil, it's spread out -- you know, disparate, spread out by hundreds of feet. Typically, the better quality rock where the oil does appear to be high saturation, it's usually less than a couple of feet thick. And the profiles around it don't have the nice, flat front edge that you normally see.

The other thing is, as far as an ROZ, it -- for example, let's look at Seminole. It was created by a situation where they think they had a trap breach. And so the water moved up after the trap was breached, and there was a little bit of sweep, very little sweep, you know, maybe a pore volume or so of sweep as that oil-water contact moved up after the trap breach, creating that residual zone.

It hasn't seen the lateral displacement that would exist in the ROZ -- or, excuse me, the sub -- what I call the Lower San Andres, below that marker. That's had multiple pore volumes of water through it, and there's been a lot of dissolution reactions. And then it's probably had a lot of H2S.

In Dr. Lindsay's model, the way he's got it described is the water was moving down from the outcrops through this interval, and then H2S was bubbling back up through it. In that world, you create sulfuric acid, and that would create the karst they we're seeing.

We're losing circulation when we get below those layers of anhydrite. So we're entering a karstic -- almost karstic-type environment, very buggy. Bugs are connected. Very high permeability. That's why we're losing circulation.

It's a different environment. That interval in the -- below those anhydrite layers has seen multiple volumes of water move through, a lot of H2S move through. A lot of water has been -- a lot of rock has been dissolved. So it's a different beast. It's a different environment.

If we got up into the interval, the Grayburg and the Upper San Andres, that Dr. Lindsay described, he's describing the karsting there as coming from more of a top-down, where you had subaerial exposure and meteoric waters were flooding in, moving down through the rock and dissolving -- creating karst and filling it with sand, silt filled into the karst, creating the San Andres Grayburg boundary.

There's karst up there. But the karsting that occurs in the -- below that high gamma ray marker is whole different beast. It's the Trentham-Melzer model that describes the large volumes of water movement through there. In that world, a couple of things that would occur. There would be a massive sweep. You'd be sweeping through intervals that probably contained only migration paths.

And the other thing that would happen, any oil that would be down there would be dead because there's too much water by, there's been fresh water by, the sweep would reduce -- would move all the light ends. The gas content would go low. It would be very poor quality and it would probably exist only in those migration pathways. So I don't see an ROZ below that high gamma ray marker, per se.

Q. On that basis, Dr. Davidson, do you have an opinion about whether that disposal zone that Goodnight is currently injecting produced water, whether it's potentially productive as an ROZ?

A. I don't believe so.

Q. What's your opinion about whether Empire's producing zone above your gamma ray marker and Goodnight's disposal zone below that gamma ray are in communication?

A. I see very little evidence of it. Predominantly, one, those bedded anhydrites are going to be very good layers. I think there's other barriers as well. Up in that interval -- there's a lot of the low porosity intervals that would potentially be barriers I think. Bill Knights is going to address that more in some of his testimony. But there are ample barriers between the two.

The other thing that bothered me is, I don't see any evidence -- I'm seeing maybe 70,000 barrels a day injected, 70,000 barrels a day produced. I think Dr. -- the modeler, Buchwalter, it seems to me that his testimony indicates the fact that there's somewhere on the order of 20,000 barrels a day was leaking up into the San Andres. I don't see any evidence of that from the production.

There was a description of fractures, you know, that might connect the two. The problem with that is that there's multiple intervals that have variable ductal behavior. And it would be very hard to keep a fracture open in that environment between the San Andres and -- with all the diagenesis and the ductility of the different rock variations.

I don't see a condition where you can have fracture communication. And if there were fracture communication, I expect you would see -- with the amount of water, again, on order of I believe about 120,000 barrels a day injected, I believe I would see a bigger impact up in the Grayburg and no increase in water at all. I would expect to see that they would be producing more water than they were injecting if there were major fracture communications between the two.

Q. Dr. Davidson, what's your recommendation to the Commission about what decision the Commission should make based on everything we've heard and your analysis today?

MR. WEHMEYER: Objection. This is outside the scope of this witness' testimony. And it's improper to speculate by this witness in terms of what the Commission should act on. But chiefly, this is outside the scope of any of the direct testimony.

HEARING OFFICER HARWOOD: Rephrase the question.

MR. RANKIN: Sure.

BY MR. RANKIN:

Q. Dr. Davidson, do you have an opinion about whether Goodnight's injection is causing waste in the purported San Andres dis- --

A. No, I don't believe --

MR. WEHMEYER: Objection. With respect to the definition of "waste," the witness has offered zero testimony in any of his filed statements about waste. You can keyword search the word "waste," it's nowhere in there. The idea of testifying to this Commission about waste is outside the scope of anything that we've had an opportunity to prepare for.

HEARING OFFICER HARWOOD: Mr. Rankin?

MR. RANKIN: Mm-hmm.

HEARING OFFICER HARWOOD: Response?

MR. RANKIN: Well, I think waste is a

question -- it is a legal term, but it's also a question of whether or not there's actually waste occurring. It's a technical issue that Dr. Davidson has evaluated in detail about whether or not there's any impact on ultimate recovery in the purported ROZ below his gamma ray marker.

And I'm asking him whether or not in his analysis there's any, in his view, adverse effect to ultimate recovery from the zone below his gamma ray marker.

HEARING OFFICER HARWOOD: I'll sustain the objection. I think he's already answered that question.

BY MR. RANKIN:

Q. Dr. Davidson, is there any basis, in your opinion, for the Commission to suspend Goodnight's existing disposal?

MR. WEHMEYER: Same objection. This is outside the scope of anything he's testified on. And it would be so multi-disciplinary, it is absolutely inappropriate for this witness to offer speculation on this point.

MR. RANKIN: If I may respond, Mr. Hearing Officer. At the very outset of Dr. Davidson's testimony, it's outlined in his direct testimony, that one of the things he was directly asked to do was to determine whether or not there's any impact from the injection. And this goes right to his opinion, that he's directly -- and it's within his scope of testimony.

HEARING OFFICER HARWOOD: Well, we've heard his opinion, and I think it's up to the Commission to decide the question that you're asking him to -- you're basically asking the witness to tell the Commission how to decide the case. So sustained.

BY MR. RANKIN:

Q. Dr. Davidson, we've heard a lot of testimony from Empire's witnesses about whether or not there's enough data for the Commission to make a decision.

In your opinion, does the Commission need more data to make this decision today?

A. I don't believe so.

Q. Why is that?

A. Well, the San Andres has been very well studied. And we brought all the data and we got the core data from the zone that arguably is one that would be amenable to some sort of EOR-type operations. In looking at what's going on in what I call the injection zone, we see no evidence of the existence of an ROZ.

You know, that increased injection, I don't think is going to be a problem. One, it doesn't appear that the pressure is significantly increasing down there.

And, again, I've looked at this thing regionally. I think everybody has maybe got a little bit of blinders on. The Trentham-Melzer theory speculates water movement from even west of the Guadalupe Mountains all the way into the Central Basin Platform. That's a big area.

And you go back and look at the Central Basin Platform before major waterflood operations started, there's been something like 7 billion barrels produced out of that. Well, this aquifer is attached to that. So there's been a tremendous amount of withdrawals.

And arguably, you know, Trentham, Melzer and one of my former colleagues at Arco, Alton Brown, have speculated that the aquifer to the west in Southeast New Mexico is connected to the Central Basin Platform. Dr. Brown actually --

MR. WEHMEYER: Object to the hearsay. Additionally, what he's speaking to he has characterized himself as speculation. So the hearsay statement about speculation would also be speculation.

HEARING OFFICER HARWOOD: We have a relaxed standard for hearsay in these administrative proceedings, but, you know, speculation on top of speculation --

MR. RANKIN: Maybe I can ask Dr. Davidson to maybe kind of reconsider or rephrase his statement.

BY MR. RANKIN:

Q. But I think, Dr. Davidson, you were testifying about the connectivity of the San Andres with broader reservoirs or formations. And I guess you can explain why you believe that's important for the Commission to consider.

MR. WEHMEYER: And with respect to communication amongst -- water communication outside of the EMSU, none of this is in the witness statements. So this is nothing that has been disclosed prior to today. We object that it's outside.

MR. RANKIN: Dr. Davidson is responding to the testimony of Empire's witnesses that he heard throughout the course of the hearing for the last two weeks.

HEARING OFFICER HARWOOD: You still have lots of witnesses to go. Are you not going to cover this testimony with anybody else?

MR. RANKIN: I think it will be addressed. So that said, I think Dr. Davidson had something to say about it and he was letting the Commission know.

HEARING OFFICER HARWOOD: Well, Dr. Davidson has a lot of say about a lot of things. I think, you know, it's not fair to Empire to bring up stuff that is new and wasn't disclosed in his testimony. So if you're going to cover it with another witness, I'll sustain the objection.

BY MR. RANKIN:

Q. Dr. Davidson last topic I want to discuss with you is one that has come up in response to questioning from Empire and also in response to some of the Commissioners' questions. And this goes to obtaining core for the Lower San Andres, the disposal zone within the EMSU.

Based on your experience, Dr. Davidson, in response to those questions and the questions from the Commission, what's your opinion about coring in the interval below your gamma ray marker and whether that can be done and whether it should be attempted?

A. Well, above the marker, you basically have a pretty tame environment without a lot of karsting. Below that marker, all indications are there's quite a bit of karsting. And I've got a lot of experience with that working with the Pemex Oil Fields. The Alcala Field is a field that I've done extensive work with, and it's got a tremendous amount of karsting.

And what they find when they try to core through the Alcala Field is when they get into the karsted intervals, you had tremendous loss circulation problems, and more often than not, they stick the core barrel, stick the pipe due to the loss circulation, and then when they do finally get the core barrel out, it contains maybe 10 percent of the core interval, and the remaining rock that's in the core is poor quality rock, and so you really don't learn much.

In drilling below those anhydrite layers, Goodnight has loss circulation and many times had to drill for long periods of time with no returns at all and losing tens of thousands of barrels into the wells. And, you know, I would caution anybody to go in and try to do a pressure core or a sponge core or anything like that the first time through until you learn about the coring conditions. It's going to be difficult because of the karsting and the loss circulation.

And, I mean, I can understand why Goodnight wouldn't do it, because you're basically --

it's an expensive operation and you're potentially going to lose a lot of equipment in the hole. And then, if you do get the core barrel out, the data is not potentially going to be that good.

Now, occasionally, a blind squirrel finds a nut. And you drill into an area where there hasn't been, you know, the extensive karsting, you may be able to get a conventional core out. But I think it would be a crapshoot.

MR. RANKIN: Thank you, Dr. Davidson.

Mr. Hearing Officer, at this time I have no further questions of Dr. Davidson.

BY MR. RANKIN:

Q. Dr. Davidson, before I let you go, I just want to make sure that you've addressed everything that you wanted the Commission to understand about your analysis and your assessment of the situation in the ROZ, purported ROZ, in the Lower San Andres.

A. I'd just like to make a statement. Hopefully I won't get objected to; I expect I will.

But I see the Upper San Andres above that marker as being a conventionally karsted interval, where it's top-down due to meteoric water input, with subaerially exposed rock.

Below that marker, it's the

Trentham-Melzer-Alton Brown we've had multiple pore volumes of water through. And it's karsted. How do I know it's karsted? Because we can inject so many volumes, so much high volume injection on the vacuum. It's got to be karsted.

Because if you look at he permeability of the rock that's there, it's not sufficiently high enough of the rock types present to handle the injection that's being injected.

I haven't seen evidence of an ROZ in a highly karsted interval. The Seminole San Andres was not. That was a situation where you had the contact move up due to a breach of a trap.

And we're moving into undocumented territory. I haven't seen a sustained ROZ project in a highly karsted interval, I haven't seen evidence of it anywhere. So I think this is potentially -- we're treading into new world looking for an ROZ in a highly karsted interval that's had this much water and H2S through it.

Q. Just to clarify, based on your assessment, it's your determination that it's not a potential ROZ in that zone, correct?

A. I do not believe so, no.

MR. RANKIN: Mr. Hearing Officer, I have no further questions of this witness and make him available for cross-examination by the other parties.

HEARING OFFICER HARWOOD: Okay. It's almost 11:35. We have a couple of options. We could -- and Chairman Rozatos, are you there?

CHAIR ROZATOS: I am.

HEARING OFFICER HARWOOD: I'm just thinking we could give Empire the lunch hour to work on their cross-examination and come back sooner, or we could start it now, and break conventionally at noon. What would be your thoughts?

CHAIR ROZATOS: I was just thinking that we break conventionally at noon.

HEARING OFFICER HARWOOD: Okay.

Are you okay with that, Mr. Wehmeyer? You've got enough to keep us going for the next 25 minutes, I suspect.

MR. WEHMEYER: Absolutely. We're happy to proceed now.

HEARING OFFICER HARWOOD: All right. Great. Then it's your cross-examination, Mr. Wehmeyer.

MR. WEHMEYER: Thank you. And just for record reference, the direct was two hours and 12 minutes, as we keep track of time.

THE WITNESS: That was shorter than your

longest witness, if I remember properly.
MR. WEHMEYER: Dr. Davidson, I'm not going to argue with you. My goal is to just get some of this testimony out so that we can get the Commission to some decisions.
HEARING OFFICER HARWOOD: Just make sure that that comment doesn't end up being a boomerang.

CROSS-EXAMINATION

BY MR. WEHMEYER:
Q. Dr. Davidson, as we talked about -- I always like to divide expert things up into qualifications, data relied on, methods and conclusions. I want to talk a little bit by way of qualifications first.
In terms of EOR experience in the Permian Basin, was the last time you had that was a little bit over 40 years ago, with Arco?
A. In the Permian Basin, yes; not in the world.
Q. Okay. So if the Commission wants to know your last EOR experience in the Permian Basin, that was about 41, 42-ish years ago at ARCO?
A. My last EOR experience in the world was a few weeks ago.
Q. Prior to this engagement, you've never had any experience at all in New Mexico?
A. Not in New Mexico, no.

Q. Now, in terms of the data relied on here, I want to visit a little bit about that. The core, we obviously have the 679 core in the EMSU that extends partially into the San Andres, correct?
A. Correct.
Q. Was there any other core within the EMSU that you had available here by way of data?
A. Well, eventually, the RR Bell.
Q. But you didn't use that as part of your first two analyses; is that right?
A. We used it for purposes of looking at ranges and porosities and permeabilities. But we weren't quite sure whether it was Grayburg or San Andres.
Q. Any other core inside the EMSU?
A. No.
Q. Now, in terms of -- I'm not talking about triple combo logs, but in terms of spectral gamma, what wells did you have available as part of your original analysis with spectral gamma in the EMSU?
A. None in the EMSU. I think one of the wells we had was in the AGU.
Q. Again, if you'll just listen to the question. The question is, within the EMSU, if the Commission wants to know what wells you looked at, analyzed, studied, correlated that had spectral gamma,

the answer would be zero?
A. I answered that question when you asked it the first time.
Q. Is it zero?
A. No. I said no, there was no wells in the EMSU that had spectral gammas that we had available to us.
Q. Now --
A. Why are we beating this to death?
Q. And, again, earlier, do you remember telling the Commission that they would not need any additional data to make their decisions here?
A. I do.
Q. So the only core we have is the 679 and the RR Bell, which you didn't use the RR Bell in the opening analysis. We have zero spectral gamma in the EMSU. What about sonic logs in the EMSU?
A. I wasn't aware of any. We went on a wild goose chase with some of the NuTech data only to find out that it was synthetic sonic data.
Q. So is the answer, as you've testified to the Commission that they have all the data they need, on sonic logs within the EMSU, you have exactly zero sonic logs, correct?
A. That's correct.

Q. Now, in terms of going back briefly to qualifications. You are not a geologist?
A. No.
Q. And you don't hold yourself as doing any expert work in this case in a geology capacity; is that right?
A. That's correct.
Q. And as we talk about tops and where the San Andres is and where the Grayburg is, I didn't take your deposition, but I've reviewed your deposition, and you were emphatic and repetitive that you did not pick any tops here; is that right?
A. That's correct.
Q. And in terms of where the Goodnight tops would have even come there, that required speculation on your part? You didn't know where the tops would have even come from for sure, did you?
A. Sure.
Q. And with respect to Netherland, Sewell, Netherland, Sewell didn't do any analysis by of the work of Mr. Knights or anyone else to identify tops here, did they?
A. No.
Q. Is that work you could have done, had Goodnight asked you to do it?

A. I wouldn't have gone down that path. I don't believe that -- Jerry Lucia used to tell me that --

Q. My question is -- if you just listen to my question. The question is, is identifying a top of the San Andres work that Netherland, Sewell could have done if it was asked? Yes or no?

A. I wouldn't have done it. Netherland, Sewell could do it.

Q. Netherland, Sewell could do it?

A. Yes.

Q. Okay. Coming back to just Netherland, Sewell and some of your experience, with respect to your day-to-day, like what you're doing on the majority of days that just occupies your 8:00 to 5:00. You with me so far in what we're talking about?

A. So far.

Q. Is that predominantly reserve evaluation or bank lending and for SEC filing?

A. Well, we do that, as well as advisory studies for national and regular oil and gas companies, as well.

Q. My question is you personally. Is the vast majority of your day-to-day, 8:00 to 5:00 work, Monday through Friday, spent performing reserve evaluations

on behalf of companies that need them for SEC filings and/or banks that are using it for lending?
A. It would probably occupy maybe 50 percent of my time.
Q. The remaining 50 percent is what?
A. Doing speciality studies for national oil companies where we're hired to do specific field studies for major and independent oil and gas companies, equity work, working when there's equity disputes between different owners in a common oil field.
Q. Can you tell the Commission about when the last time you would have been personally engaged to identify impermeable barriers?
A. That would be probably a few weeks ago.
Q. In what context?
A. We're working on another lawsuit in Australia, where migration up and down the wellbore is one of the contentions. I can't give you any details on it. It's confidential.
Q. Coming back to just what Netherland, Sewell does -- and, again, I'm just -- I heard in your description and response to Mr. Rankin's questions you specifically mentioned assisting with reserve evaluation and bank lending and for SEC filings.

You would agree here, as we just talked forest for the trees, forest for the trees, NuTech performed two rounds of oil-in-place evaluation here that would both be significantly more optimistic than what you came up with. True?

A. Correct.

Q. And Ops Geologic performed work here and arrived at oil-in-place estimations that would also be significantly optimistic to what you and Netherland, Sewell did here. Isn't that true?

A. That's correct. But they're also optimistic to the core measurements.

Q. Well, let's speak to the core measurements just briefly. But before I do that, you've also been in the examination room when the Exxon sales brochure has been published? You've seen that?

A. I have.

Q. And you can tell the commissioners that Exxon is also significantly more optimistic about its estimations of oil in place at EMSU as compared to the work here that Netherland, Sewell did. Yes?

A. Yes. And if you look at their 25 percent average through the 679 core, the core data doesn't support that.

Q. With respect to the 679 core -- well, let's

just put a bow around this. So we've seen two rounds of analysis from NuTech, we've seen Exxon's analysis, and we've seen Ops Geologic analysis. And you can tell the commissioners that, this is just a yes or no, Netherland, Sewell here is pessimistic to all four of those evaluations. Yes?
A. I'd say Netherland, Sewell is correct and the others are all overly optimistic.
Q. Your testimony is they've all got it wrong?
A. Yes.
Q. As we talk about -- do you remember visiting about certainty back in your deposition?
A. Mm-hmm.
Q. And you said here that in terms of your oil in place, if you were to put a percentage on it, that would be 50 percent certain.
A. No. I said it was a 50 percent probability, which is a most likely case. If you read my corrected version of my verbal testimony, I made that correction. I didn't -- I was talking about a P50, 50 percentile probability, which is a most likely case. And that was corrected in my written response to the verbal deposition.
Q. So you wouldn't use the testimony you changed from the first time you swore to the

50 percent?
A. I misspoke in the first time, which Ms. Shaheen tripped me up. I was talking about probability. Not uncertainty. I was talking about 50 percentile of a probability range. And, again, I corrected it in my -- in the testimony to reflect that properly.
Q. Let's look briefly at the testimony, since you just said that Mr. Shaheen tripped you up, that this was something she did.
A. It wasn't on purpose.
Q. You said --
A. I misunderstood the statement when it was given and I said yes, when I should have clarified that it was 50 percentile uncertainty, on the uncertainty range, not 50 percent uncertainty.
Q. So I'm going to try to share the screen, if I can do this correctly.
As we talk about this 50 percent and Ms. Shaheen tripping you up, do you recall what she was asking you about was the certainty with respect to potential residual oil zones and oil in place? Do you remember that?
A. Mm-hmm.
Q. And you said, I'm reading from Page 46,

Line 21, "I'm saying we can't say that we could differentiate between 35 or 36 percent, but the evaluation would be reasonably certain to identify intervals that would be potentially residual oil zones."

She asked you again, "And so, again, I don't think you've answered my question yet. What do you mean by 'reasonably certain'?

"ANSWER: I would be reasonably certain that we identified potential intervals containing mobile oil under CO2 flood.

"And does reasonably certain mean that you are 50 percent sure?

"ANSWER: That would probably be a reasonable estimate. That would be a most likely estimate."

And then you were asked about the aerial continuity as a result of sparse well control, and you said, "That's part of the problem; we don't know the aerial continuity."

So, again, when you told Ms. Hardy that -- strike that. When you told Ms. Shaheen that you were reasonably certain, that is, 50 percent certain, that you've identified intervals that would be potential residual oil zones, it's now your

testimony that you meant something else?
A. I meant that the -- our estimate would be a mostly likely case, which I said in the very next sentence. It's mostly likely -- I corrected the testimony to represent that it wasn't 50 percent -- I'm 50 percent certain that it's a P50, or a 50 percent probability, which is a most likely case. Our answer is a most likely case.
Q. Now, the core, we visited with Mr. McBeath a couple weeks ago, he said core is direct evidence. And you would tell this Commission that based on the opinions of Netherland, Sewell, we don't need a core down to the bottom of the San Andres here, right?
A. I'm not saying you don't need one. I'm saying it would be very difficult to get one. I'm not sure of the value of it, given the fact that there doesn't appear to be much oil down there.
Q. In terms of your oil-in-place assessments, isn't the rock facies very important to that?
A. Yes.
Q. You have to know what is the rock facies down in the San Andres, because if you're off on the rock facies, everything else falls apart; isn't that right?
A. Yes.

Q. With respect to the different rock facies, there's been a lot of discussion about wackestone. And I've heard it different ways. Do you pronounce it wackestone or wackestone?
A. I prefer wackestone, because the other sounds silly to me. But geologists would disagree.
Q. Okay. I'm been calling it wackestone, but I thought I heard somebody today call it differently.
And then you would say, that's the least desirous rock facies, or there's even worse than that?
A. Mudstone. Lime mudstone is worse.
Q. Do you have lime mudstone in your interpretations?
A. We did. When we found thick limes less than 5 percent, it was generally classified as lime mudstone.
Q. Is that what you're calling the non-reservoir?
A. It's generally non-reservoir, yes.
Q. I'm just trying to get to your terminology, because in your papers, you discuss non-reservoir. Is that what you're calling --
A. That was the non-reservoir facies, yes.
Q. So we have wackestone, and then you would move over one to mud dominated packstone; is that

correct?

A. That's correct.

Q. And then you would move over to a grainstone?

A. Grain dominated mudstone.

Q. And then as you continue moving over, what would be the next?

A. Grainstone and then a moldic grainstone.

Q. Now, as we come back to the core here, did you ever personally look at the core?

A. Never had the opportunity.

Q. What did you do to try to gain access to the core to be able to actually evaluate the core?

A. I wasn't aware that it was available at the Bureau, or I would have gone to look.

Q. Why were you not aware that the core was available at that time Bureau?

A. I didn't know where it was.

Q. As we talk about studying the core being our direct evidence here in terms of rock typing, can you tell the Commissioners about everything you did to try to get access to that core?

A. I didn't try at all. I assumed that it was -- that Empire had it and we couldn't get availability to it.

However, looking at the core, being valuable in and of itself, I had the core measurements, and with the core measurements and with the data we had from the outcrop, I was able to do a reasonable job of rock typing based on what I learned from the outcrop study.

Q. Okay. And I may have forgotten my -- I thought my question was: Can you describe to the commissioners everything you did to get access to the core?

A. I told you, we didn't know that we could get access to.

Q. The RR Bell, did you ever get access to the RR Bell core to evaluate that core?

A. To be honest with you, I was a little surprised that Dr. Lindsay went back and looked at both cores and we weren't invited to go look at it with him.

Q. So the first time was Ms. Shaheen's fault and this one is --

A. I'm not saying it's --

Q. -- Dr. Lindsay's?

A. I'm just saying, we weren't aware that the core data was even available.

HEARING OFFICER HARWOOD: Doctor, it's human nature, but for the court reporter's sake, you guys please try not to talk over each other. She can only take down one person at a time.

MR. WEHMEYER: And I apologize to Madam Court Reporter for my part in it.

BY MR. WEHMEYER:

Q. Now, coming back to the RR Bell, you said, Doctor, you were surprised, was how you described it, that Dr. Lindsay didn't invite you to look at the RR Bell core or the 679 core.

And so earlier, when you said that you would maybe be 50 percent certain on your oil-in-place estimations, and you said that was the fault of Ms. Shaheen, for tripping you up, the reason you didn't look at the cores here as part of your work, your work being very important by way of facies of work, that one's Dr. Lindsay's fault for not inviting you?

A. I don't know if it's anybody's fault. It just seemed like if data was being evaluated, both parties would have been invited to take -- you know, that's not my -- that's not my position to lay fault. It seemed like it would have been a fair thing to do.

Q. But Dr. Lindsay, who you've heard testimony in this case, the first witness that Empire called, he

did actually study the RR Bell core, didn't he?
A. He did.
Q. He also studied the 679 core, didn't he?
A. Yes.
Q. Now, in terms of any fracture studies, did you perform any fracture studies from any of the core?
A. No.
Q. But you did see that Dr. Lindsay performed a fracture study in connection with the 679?
A. Yes.
Q. He's also prepared one for the RR Bell. I don't want you to say you wanted information. Would you like to see the RR Bell fracture study?
A. At this late stage, it wouldn't be of any value to me.
Q. Why is that?
A. We're coming to the end of the hearing.
Q. But isn't the goal here to get it right?
A. Yes.
Q. Okay. Now, in terms of any other fracture studies, did you see any other fracture studies by way of data relied on here besides the one prepared by Dr. Lindsay?
A. I did not.
Q. As you talk about the concept of

communication between the Grayburg and the San Andres, wouldn't fracture studies be something you would want to see?

A. Assuming it was available. But in my view, the fracture studies up in the Upper San Andres wouldn't have much impact on what's going on down in the Lower San Andres.

Q. Do you know what areas Dr. Lindsay performed his fracture study on in terms of in relation to the Lovington Sand?

A. I assume it was above. But below the Lovington, it would be very hard without core data to infer much of anything because of the high ductility of some of the intervening layers. And it would be hard to predict whether the fracture penetrated down or not, whether there had been any diagenesis that had closed the fractures, what the stress field was, you know, what's the arc of the formation top, where in the system do I go from extensional to compressional? Again, do I have ductal layers that would isolate the two? I didn't see anything that went to that level of sophistication.

Q. Is your testimony to the commissioners that you don't even know where, by way of depth interval, the fracture study that Dr. Lindsay performed is?

A. I suspect he did a regional study that would include projecting down. But that's a very hard thing to do without direct evidence to support other than the geomechanical model that would predict such an extension.
Q. My question is, do you know where, by way of depth interval --
A. I do not.
Q. -- Dr. Lindsay's fracture study was performed?
A. I do not.
Q. But that didn't stop you from offering opinions to the commissioners here under oath about communication between the San Andres and the Grayburg, correct?
A. That's correct.
Q. The other thing I want to ask, as we talk about the core on 679, did you anything to depth shift that core in relation to the wire line?
A. Yes, we did.
Q. How far did you depth shift it?
A. If you'll remember, it was variable, but it was a few feet up and down, up and down the core.
Q. Now, as we talk about how important your rock facies is, wouldn't it be important to look at --

the only core description you've seen here was the one prepared by Dr. Lindsay on the 679, right?

A. No. I saw the core description prepared by I guess it was Western Atlas, whoever wrote the report, the digital report.

Q. Did you rely on either one?

A. I relied on both.

Q. Now, I want to see if I can get over -- I have this on a poster board, if it helps.

What we've done is actually compare your rock facies against Dr. Lindsay's core description and core interpretations. Have you ever actually tried to correlate here by actually mapping your different facies against Dr. Lindsay's descriptions in a graphic such as this?

A. I have not.

Q. I'm trying to get to this. Is it coming up where you can read it?

A. I'm never going to be able to see this, so get on with your point.

Q. I guess, how --

MR. WEHMEYER: May I approach with the poster board just in case it helps?

BY MR. WEHMEYER:

Q. I knew you had some vision issue, so I wanted to be sensitive to that, so I have this in hard copy.

HEARING OFFICER HARWOOD: Mr. Rankin, if you need to move to see.

MR. RANKIN: I don't know who prepared this. It wasn't part of anybody's direct testimony or cross or rebuttal. I don't know where this came from. I guess that's one of my initial questions.

BY MR. WEHMEYER:

Q. Do you see Dr. Lindsay's core description on the right?

A. Mm-hmm.

Q. And they've been compared against your facies model off of this board --

MR. RANKIN: Mr. Hearing Officer, additional objection for clarification on the origin or providence of this exhibit or potential exhibit. I don't know where it came from, I don't know who prepared it, and I don't know the foundation for it at this point.

HEARING OFFICER HARWOOD: Well, it's not being offered as far as I can tell. So far it's a demonstrative aid.

Is that correct? Mr. Wehmeyer?

MR. WEHMEYER: That's exactly correct.

Thank you.

HEARING OFFICER HARWOOD: By the way, we're at the noon hour. But go ahead if you want to finish your point.

MR. WEHMEYER: If you'll indulge two minutes, I think I can finish.

HEARING OFFICER HARWOOD: All right.

BY MR. WEHMEYER:

Q. So here, for example, in your facies model in the 679, do you see this large interval as you're showing as non-reservoir?

A. In our model any interval below 7 percent porosity is considered non-reservoir.

Q. I'm just saying, in your model do you see that there's this large interval that you describe as non-reservoir?

A. I don't know how you got to those -- how you got to that figure.

Q. The figure -- this is straight out of your work, where you showed this interval right here as non-reservoir.

A. And we eliminated intervals that indicated high anhydrite saturations as non-reservoir, yes.

Q. But if you go over to Bob Lindsay's core description, he actually has laid eyes on this core, studied it, wrote about it is, in fact, peloidial packstone where the core reports oil saturation of 13 percent. Can you just explain to the commissioners how, under your modeling, when the direct evidence we have comes out of the 679 core, you could be showing something as non-reservoir, that under Bob Lindsay's description, is 13 percent oil saturation and peloidial packstone?

A. In our modeling, we eliminated intervals that were lower than 7 percent porosity that had indicated elevated anhydrite contents from the core measurements that we used to calibrate the model.

I realize that some of those intervals in the core -- we also pointed out that we were concerned that intervals that had indicated high anhydrite intervals could be potentially damaged during the core handling procedures, and we felt like they were somewhat unreliable from the perspective of doing a core match.

So from the combination of eliminating low -- what indicated low porosity rocks, indicated -- our modeling indicated a high -- potentially high anhydrite values, we eliminate some of the rocks, that actual core measurements, from the modeling procedure so as to try to concentrate on the better quality rock.

Q. If we move just a little bit deeper in the wellbore, we have sections with 30 percent saturation, oil saturation, actually measured in the core and described by Bob Lindsay, Dr. Lindsay, as reservoir rock. And you're showing that non-reservoir. How can that be?

A. Again, those would be intervals where the log indicated they had high potential anhydrite.

I'm curious how you got to that description. That was never delivered.

Q. What was not delivered?

A. The facies model values.

Q. Did you actually take the facies model to see where in relation to Dr. Lindsay's descriptions the rock types --

A. We did. And, again, there was concern some of that data was associated with karsted intervals that potentially contained anhydrite that wasn't there anymore by the time the core came to surface.

So rather than try to deal with the uncertainty, we eliminated it and concentrated on modeling where we didn't have the uncertainty in the presence of anhydrite.

Q. Well, at 4200 feet TDB, did Dr. Lindsay describe karsting?

A. He did. And karsted interval is potentially one where you would have had anhydrite, and that anhydrite may not be there anymore by the time -- this well wasn't cored with salt -- the salt-saturated fluid. And there's a potential that anhydrite that may have been there wasn't there anymore.

They certainly saw that in the outcrop barriers, intervals in the outcrop, that anhydrite would be completely dissolved away.

I wasn't sure enough, I wasn't sure whether or not that potential existed. So rather than deal with the uncertain data, we ignored it when we were doing the core modeling.

Q. You ignored what?

A. The intervals that had indicated high anhydrite content from the logs.

Q. Your facies model doesn't even identify the Lovington Sand, does it?

A. I don't know what the Lovington Sand is.

Q. So as we talk about how important your model -- facies is to your model, you do not even know what the Lovington Sand is. True?

A. It's described as a dolomitic sandstone.

MR. WEHMEYER: I'm trespassing on the

goodwill of folks who want to eat. I'm happy to pick this back up after lunch, or proceed at the Commission's pleasure.

HEARING OFFICER HARWOOD: Okay. Mr. Chairman, what is the Commission's pleasure? When do you want to reconvene?

CHAIR ROZATOS: I'm sorry, can you repeat it please.

HEARING OFFICER HARWOOD: It's six after 12:00. Mr. Wehmeyer is at a stopping point for now. What's the Commission's pleasure in terms of when we reconvene?

CHAIR ROZATOS: Let's come back at around 1:15.

HEARING OFFICER HARWOOD: 1:15 is it. Thank you we'll be off the record until then.

(Lunch recess was held from 12:06 to 1:15 p.m.)

HEARING OFFICER HARWOOD: So I'll just remind Dr. Davidson, you're still under oath, and turn it back over to Mr. Wehmeyer.

MR. WEHMEYER: Thank you.

BY MR. WEHMEYER:

Q. Going back to qualifications and some of the data we relied on here, have you had experience with residual oil zone development before this engagement?

A. Directly, no.

Q. So, as we talk about the work of Mr. Melzer and Bob Trentham, this would be your first residual oil zone project, correct?

A. As they define it, yes. But we deal with the residual oil all the time and why I do it. So, it wouldn't be the first time I've dealt with doing evaluation through an interval that has residual oil. It'd be the first time that I've done it in terms of an ROZ as defined by Trentham as an EOR project.

Q. Now, in terms of -- I want to talk about some of the work done. Jonathan Martel actually did a great deal of the work here for you, didn't he?

A. He did the actual push the buttons to run the model.

Q. Did he not also build the databases and build the computer models?

A. Well, we built the models together jointly. We write the code. He's responsible for populating the databases and getting the data ready for input and output.

Q. And so Mr. Martel did all of that work. Yes?

A. It's Markell, by the way.

Q. With a K?
A. Markell.
Q. Okay. And we haven't seen any witness statements in this case for Mr. Markell, have we?
A. You have not.
Q. Now, coming back to the facies, and visiting about how important the rock facies are, and I want to kind of frame some of this oil in place, if for purposes of your oil in place, if there was less, based on your modeling, if there was less than 20 percent residual -- strike that. If there was less than 20 percent oil saturation -- you with me so far?
A. Mm-hmm. Yes.
Q. -- you can tell the commissioners that your model credits zero oil towards the oil-in-place volumes; isn't that right?
A. In the summations that are generated to -- I'll put it this way. In the intervals that exceed 20 percent oil saturation, all oil is counted. In the intervals that are less than 20 percent oil saturation, we don't count them because, one -- there's two reasons for it. One, after 40 years of --
Q. And, Dr. Davidson, this is a yes or no question. In your model, in terms of telling these commissioners about opinions as to oil in place, if it

is below, under your modeling, 20 percent oil saturation, zero of those volumes are credited; isn't that true?

A. Zero of those feet are credited.

Q. Likewise, as we talk about permeability, if, based on your modeling, an interval has less than 1 millidarcy of permeability, your model credits zero oil for any oil in place that would be in an environment at, according to you, less than 1 millidarcy; isn't that correct?

A. That's not correct.

Q. Explain that.

A. Okay. Our cutoff is a tenth of a millidarcy. And when that's our cutoff and we don't actually use the permeability calculated to calculate that, we use a 7 percent porosity cutoff, which came from a -- that's the permeability porosity cutoff with the available core data, using the tenth of a millidarcy as a cutoff permeability. So the permeability cutoff is actually .1 millidarcy.

And then for the assumption of, is there a vertical barrier or not, we take the vertical -- the horizontal permeability that came out of Seminole San Andres and then used that to generate flags that indicate the existence of potential barriers. But

those barriers aren't used in our modeling for oil in place. Those were flags to demonstrate the location of potential barriers at the request -- because I was asked to identify potential barriers as part of my evaluation. But as far as the cutoffs, as far as oil in place, those were not used.
Q. Additionally, just big picture so that we don't lose the forest, did you use 7 percent effective porosity or 7 percent total porosity?
A. As it came out of the model, it would have been effective.
Q. And so if there was oil in intervals that you assessed as being less than 7 percent effective porosity, there's also zero oil credited in your oil in-place volumes at those intervals; isn't that right?
A. That's correct.
Q. With respect to data here, you also have had zero oil samples out of the EMSU; isn't that correct?
A. Oil samples out of the EMSU. I don't hold an oil sample from the EMSU. No, I don't have one in my office.
Q. You also performed no oil miscibility studies within the EMSU, and you haven't seen any either, have you?
A. That wasn't part of my job. That wasn't

part of what I was hired to do.
Q. With respect to EOR and CO_2 injection, that's going to lower the porosities and the permeabilities that otherwise might be perceived as cutoffs in a conventional primary recovery; isn't that right?
A. I don't agree with that.
Q. Let's get into -- we've talked about some of the geology and that you're not a geologist. I want to go to one of the slides that you used earlier.
So would you agree that there was a lot of geology discussed in your opening remarks with Mr. Rankin?
A. I discussed depositional environments.
Q. That's really more of the geology thing, isn't it?
A. It's part of petrophysics. It's a big part of petrophysics.
Q. I want to ask, in terms of the karsting that you described, can you describe to the commissioners how this karsting occurs?
A. There's a lot of different ways that it can occur. Shallow, the theory is that you have meteoric waters, which would be fresh waters, penetrating exposed carbonate surfaces and creating dissolution where the water penetrates. And that could create

karst.

But the way it was described by Dr. Lindsay was it created kind of sinkholes that ultimately filled in with other materials. That would be what I would call top-down karsting. We see that sort of thing routinely in the San Andres.

Another type of karsting occurs due to the movement of acidic waters through the rock where you get dissolution precipitation reactions where the rock is dissolved. It generally moves through the higher -- fluids move through the higher permeable rock and you start generating pathways, dissolution pathways between the bugs. And then, ultimately, the bugs get connected and enlarged. And then when they become large enough, you can get something called a collapse breccia, where the rock actually collapses it on itself. And that's a different type of karsting.

Q. All of that is happening at the surface level in shallow water environments, isn't it?

A. I don't think -- I don't really agree that the massive karsting that comes from the model that Bob Lindsay put together with the counterflow of H2S in meteor waters, I'm not sure -- I don't think that's a surface phenomenon, no.

Q. In terms of evaporation and evaporative cycles, this isn't happening? To get this evaporation, that has to happen at the surface?

A. Well, evaporation doesn't have anything to do with the karsting. Evaporation has to do with the development of the evaporate layers.

Q. I want to go -- because I think we can short circuit a lot of this. At Slide 16, in response to Mr. Rankin's questions, you shared with the commissioners your opinion that the San Andres was a high energy environment; is that right?

A. The Upper San Andres is in a high energy environment. So above what I'd call the high gamma ray marker, it was a higher energy environment. And then below the gamma ray marker, I'm moving more towards, I guess, the outer ramp environment, where sea level changes can dramatically change the characteristics of the rock over short distances.

Q. In your earlier testimony, you described all the way through the San Andres that it is a high energy environment. Are you changing that testimony now?

A. I didn't -- No, that's not what I testified at all. I said the Grayburg San Andres interval above that marker is generally a high energy environment. Below that marker, where the gamma ray baseline

shifts, I'm moving to a high frequency environment where I'm seeing very rapid sea level shifts where the rock quality is changing from good to medium with these evaporite boundaries on it. Then, as I move deeper in the San Andres, I'm moving more and more into a deeper water, lower energy environment.
Q. You describe anhydrites throughout the Lower San Andres. Yes?
A. We see evidence of them. Now, they're not all layered, they're not all bedded anhydrites.
Q. Anhydrites are going to be formed at the surface, aren't they?
A. That's correct.
Q. And you heard Dr. Lindsay's testimony that this was not a deep water environment here at the EMSU for the San Andres. Do you remember that testimony?
A. I don't know what he said for the San Andres, because I don't think he looked at any San Andres cores here.
He said that there were no bedded anhydrites in the Grayburg or in the Upper San Andres in the cores that he reviewed. He said there was only anhydrite cement.
Q. My question is, you do not recall Dr. Lindsay testifying that the San Andres, at this

particular EMSU location, would have been a shallow water environment, not a deep water environment?

A. Well, if he said it, I don't agree with it.

Q. And with respect to the qualifications of the geologists, you would have to tell the commissioners that Dr. Lindsay is far more qualified than you as a geologist; isn't that right?

A. I don't know that he -- he was describing the San Andres underneath the -- underneath the gamma ray marker.

There tends to be a tendency to define the San Andres as what has been seen in the core and ignore that it could be different deeper in the section.

Q. Would you want core to be able to say it is different?

A. I can see that it's different from the gamma ray response.

Q. Well, let's talk about the gamma ray response. Now, the gamma ray there would be, according to you, measuring uranium, correct?

A. That's correct.

Q. How do you know, since you don't have spectral gamma, that it is not measuring potassium or thorium?

A. Because everywhere I've looked at spectral gamma rays, Maljamar, I believe in the AGU, at Seminole, everywhere I've seen a spectral gamma ray, the thorium and potassium are extremely low and the gamma ray is responding predominantly to uranium.

Q. In terms of any actual logs in the EMSU, you have no spectral gamma to be able to make a differentiation between uranium, thorium or potassium within the EMSU, do you?

A. No. But I haven't been outside it.

Q. Now, you've talked about the gamma response I think at where you would call the -- what you're now speaking to in terms of an impermeable barrier, the gamma kick?

A. I don't know if it's impermeable or not. I just see that that's a mappable high gamma ray marker that can be mapped across the entire EMSU.

Q. So as we talk about that gamma ray kick that you've described that's mappable across. You've shared before the break that you don't know where the Lovington Sand is, you don't know what it is. It's not your testimony that that is an impermeable barrier; is that right?

A. I don't know anything about the Lovington Sand.

Q. So, just in terms of illustrating the gamma ray kick, did you hear Mr. Bailey's testimony about the Lovington Sand is basically arkosic sands that have blown off of the ancestral Rocky Mountains and deposited at that location?

A. I heard that testimony, yes.

Q. That would be a shallow water environment, wouldn't it?

A. It would.

Q. Okay. So we know that the Lovington Sand would be shallow water environment. And you don't have any basis to disagree with Mr. Bailey's testimony about that coming from -- arkosic sands being blown off of the ancestral Rockies. Why would those have uranium in them?

A. I don't agree with that. There's been work that's been done at Slaughter on the Lovington Sand that shows that they're not arkosic at all; that the elevated uranium comes from organic matter.

Q. Okay. Wouldn't this be a question for a geologist?

A. I'm just reading what geologists say about the Lovington Sand.

Q. And you've heard Mr. Bailey's testimony in here. Would arkosic sand create a gamma ray response?

A. Arkosic sand would imply the presence of feldspathic inputs that would have radioactive potassium in them. But what I'm telling you is, I was told that early on, that that was the theory about what was going on, but I've also done some research and it's been determined, at least north of the EMSU, that that elevated gamma ray is a result of the presence of organics in what's called the Lovington Sand. I don't know if the Lovington Sand makes it to the EMSU or not. I don't know.

Q. Now, as we talk about the gamma ray marker in the EMSU, and if you just assume with me that the gamma ray is Lovington Sand, is that basically where you change from a shallow water rock facies and then begin using a deep water rock facies?

A. That's not true at all.

Q. Explain that.

A. I go from a predominantly shallow water environment above that, due to the low gamma ray, the typically low gamma ray, and then I go to a cyclic shallow to medium depth back and forth, back and forth with evaporite caps.

Q. Is the gamma ray different above the Lovington Sand versus below?

A. That value, if you draw a baseline through the middle, yes, there's a shift below the Lovington Sand.

Q. Is it a significant shift?

A. Well, it's significant in that if the response is predominantly dominated by uranium, which I believe it is, then that shift would indicate, roughly, two to three times the uranium content.

And the uranium content of the ocean didn't magically increase below that marker. What happened below that marker was that the grain size, the average green size of the material, got smaller. And basically, the way it works out, a three times increase in uranium would imply about one-third the average grain size.

And Lucia has shown that as the grain size mud content increases, the permeability goes down. And if it's a three times increase in uranium, you would lose about an order of magnitude of permeability. So there would be a change in the rock behavior below that marker in my opinion.

Q. And the question was just, was it a significant change in the gamma ray? And I think, after all that, the answer is it's not a significant change.

A. No, it is significant in that it would imply a major change in average grain size and a loss of permeability.

Q. With respect to the change in rock facies, we've talked about the data that we don't have, would you agree with me that you could at least be off by one level of rock facies, instead of -- agree with me that instead of mud dominated packstone or -- let me strike that -- agree with me that instead of wackestone, this could be mud dominated packstone?

A. Well, one, we don't have wackestone in the model at all. And two, that there's a spectrum of rock types between those that we model so that we can model the entire range that was present in the core data set.

So, for example, we can model between a mud dominated packstone and a grainstone to determine a grain dominated packed stone. When the porosity starts increasing in the grainstones -- the average porosity of a typical grainstone is 10 to 14 percent. When we start getting higher porosities of that, it's indicative of the presence of bugs. So we move from a grainstone to a moldic grainstone.

Q. The question was, would you agree with me that there's at least sufficient uncertainty here that you could be off on your facies by a magnitude of one?

A. I don't know what that means.
Q. For example, moving over from wackestone to dominated packed stone, Could you be off by one facies? Is there enough uncertainty in the data to be off by one?
A. For one, there's no wackestone in the model. And two, there's a continuum between. So there wouldn't be a quantum jump from one to the next.
Q. Would you agree that you could be off by approximately that magnitude if you want to average them overall to the depths?
A. I don't know -- again, I don't know what that means, because there's not one facies. I mean, it's -- it's not a -- it's not a quantum shift from one to the next. It's a transition from one to the next.
Q. In terms of just moving from one to the next, could you be off by the next?
A. I suppose I could.
Q. What does that do to your oil saturations in your model if you were off by one magnitude?
A. Again, it's not -- the oil saturations aren't predicted based on discrete rock types. There's a spectrum of rock types between -- that sweep that entire range presented in the core data.

Q. I'm going to try to work through these in order here.

At your Slide 2, you said you did review the facies descriptions from Dr. Lindsay?

A. As best we could. We didn't have a good picture of it. We tried, and we could make out the facies. The problem that we had there was I had no idea what the resolutions were of those. We built a model based on discrete core plug by core plug measurements tied back to the Lucia-Kerans model.

And I don't know whether Dr. Lindsay was describing individual core plugs, or was he going up and down the core and describing what he saw at a different resolution. So I don't know -- there could certainly be a disconnect between the plug-based cross-plot to determine the facies of a specific plug versus a general description of looking at the core and describing a depositional environment.

Q. Do you agree with Dr. Lindsay that the San Andres is high on the carbonate ramp?

A. I would -- the Upper San Andres probably is. The problem is, you keep saying "San Andres" and it's not just the San Andres. There's an Upper San Andres, and then there's a San Andres deeper in the section that's below that gamma ray marker.

Q. I'll indulge the difference that you're trying to draw here.

The Lower San Andres, you'd disagree with Dr. Lindsay that that would be high on the carbonate ramp? Or you don't know?

A. The very upper part of that, where we have the high frequency sections, would be just at wave base and just below wave base, depending on where I am in that high frequency sequence.

As I get deeper in the San Andres, as I go below that high frequency interval, I'm getting increased mud content, which would indicate that I'm moving down the carbonate ramp more into the basin.

Q. The question is, are you disagreeing with Dr. Lindsay that the Lower San Andres is high on the carbonate ramp? Or is your answer, "I don't know"?

A. There's portions of it that are near wave base on the carbonate ramp; I guess you could say that would be high on the carbonate ramp. And there's portions of it that are in the deeper water portion of the carbonate ramp.

Q. And that's, according to you, in the Lower San Andres?

A. In the Lower San Andres.

Q. How many feet of the Lower San Andres, according to you, are on the upper carbonate ramp?

A. In the Lower San Andres?

Q. Yes.

A. I haven't quantified it.

Q. In talking on the core earlier, before we broke, you said that you did depth shift the core. If you didn't have core gamma ray, on what basis did you shift the core?

A. Basically, we calculated the porosities using our porosity model. And then we looked at the core porosities and then moved the core sections up and down in order to get the core porosities to best match the right porosities.

Q. On your core oil saturations, did you come to the opinion here that a lot of the water was lost as a result of hydrocarbon expansion, dissolved gas?

A. Yes.

Q. So if that water was lost because of dissolved gas, that means we have oil in that core, don't we?

A. Yes.

Q. Do you agree that the adjustment would not be uniform from top to bottom and that you're going to have differences at different places in the core?

A. Yes.

Q. Did you hold it constant or did you make adjustments throughout the core on the saturation correction?
A. We pretty much -- what we did is we determined the average value of the bleed factor and applied it throughout the interval.
Q. I'm sorry, so was it held constant?
A. The bleed factor was. The B sub o I think it was as well.
Q. But you would agree for the commissioners that that would actually be -- you would need variable corrections throughout the core?
A. Well, the interesting thing was, when we went back and looked at the bleed that occurred at Maljamar, it was variable, but it wasn't uniform from top to bottom, as you would expect.
And what we found when we did the evaluation in the Maljamar core, in order to get the best match between what we would call corrected data -- because basically with a pressure core, you can get an equivalent of what an uncorrected core would be. And because of the way they do the analysis, the bleed is quantified separately, and you can get, I guess, a mimicked picture of what a conventional core saturation would have looked like.

In looking at that, you look up and down the core and you can see it's not exactly it -- I think there the average was about 19 percent. It wasn't necessarily 19 percent at every interval, but there wasn't a discrete trend noticed from top to bottom.

And so the best match we got when we went back and practiced with the Maljamar data set was used in the average. That gave us the least uncertainty between the corrected core saturations and the actual measured saturations. So we didn't see the variation that you're talking about when we were working with the Maljamar core. We certainly checked for it because I wanted to see is there a depth related.

Because in Maljamar, we went from the main production zone to the interval below the oil-water contact. And I was curious whether I needed to change the bleed factor based on those factors. We saw that we didn't need to get the best match.

Q. I'm not talking about a match. My question is, you would agree that the correction factor is going to be different as you move through the core, it's going to be different in different places, it's not a static? And in this particular case, you used a

static one. You did not attempt to vary it. True?
A. That's true.
Q. Thank you. Now, as we continue moving through, we're now at Slide 5 of your presentation. Now you're talking about Guadalupe Mountain outcrop here. Yes?
A. Mm-hmm.
Q. So obviously, this is weather exposed?
A. They dug down -- they actually described the process of peeling off the surface and getting that deep enough to try to get the interval where the weathering was not impacting the results. I'm very careful about that.
Q. So you think that this outcrop study was not affected in any shape, form or fashion by the weathering of the stone?
A. It was affected by the fact -- again, they made every effort to get past the weathering layer, if you want to call it. There's a proper geologic term for that; I can't remember the name for it.
But they dug down deep enough into the rock to convince themselves, at least, that they were below the interval with which weathering -- however, they did point out, because of all the water that had gone through, that they could not quantify accurately

the amount of anhydrite that may have been there originally.

The other problem that you get to with outcrops is because of the ice fracturing, you can't really do accurate fracture analysis on an outcrop. And they didn't attempt to do so.

Q. The permeability in the San Andres here at EMSU is higher than the permeability that was measured at the Guadalupe outcrop, isn't it?

A. Not necessarily. These are average values. And if you go back and read the paper, you see that there's a range of permeabilities that were associated with each rock type. And these written here are the averages based on multiple samples of each rock type.

Q. The averages in the San Andres are above the average permeability reported at Guadalupe Mountain; isn't that correct?

A. I don't know that that's correct. It really doesn't matter. In the calibration procedure, the way that the cross-plot is defined is divided into regions. And when the core -- permeable -- the cross-plot crosses the permeability, it lands in a space, and that space defines the rock class or rock facies, not the specific point.

For example, we went and assigned a 12

percent porosity and a 17 percent permeability to the grainstones in our model. We just used the cross-plot technique to identify the different facies present.

Q. I'm moving now to Slide 6. Here we have the resistivity index is on the Y axis, and water saturation is the X axis; is that right?

A. That's correct.

Q. What is the reference for the data used to make the critical water saturation lines?

A. That's in the paper. It's a Schlumberger model. And basically, what you do is -- the process was this, I described it earlier, we identified -- based on the cross-plot that was prepared from the outcrop, we identified the rock class or rock facies.

We grouped the rock facies -- for a particular face, for example, let's just say grainstone, we grouped all the points that were identified on that cross-plot analysis as grainstones. And then we plotted them on this plot.

And then, if you take that equation on the bottom left-hand side of the figure and solve it for Sc, you can get an Sc value for each core point, and then we just average the Sc values. And then we plotted that line as a function of saturation to make sure that it actually did -- it was a reasonable representative expression of the behavior of those points that were identified as grainstones.

Q. Is the answer that this was not your data, this came from a Schlumberger reference?

A. No. This is the data from the EMSU. The model that describes it was developed by Schlumberger to handle this type of analysis for an oil carbonate.

Q. The reference data.

A. No, no. That --

Q. The reference data used to make the water saturation lines, is that reference data Schlumberger?

A. No. It's -- that data on that -- the data on that cross-plot is EMSU data from the core. The model, the equation at the bottom left, is based on a model developed by Schlumberger to handle oil wet reservoir. And it's in my -- the references are in my testimony.

Q. If we move over onto the right side, is the W, is that wackestone?

A. It is.

Q. What is the water saturation there in your plot for wackestone?

A. In the plot, it would probably be north of 90 percent. However, I'll remind you that wackestone wasn't included in our model.

Q. What is your poorest rock then, if it's not wackestone?
A. My dominated packstone.
Q. What is your water saturation from that dominated packstone?
A. It's variable. You can see it varies depending on the resistivity index.
Q. Up at the very top, at 100 percent, I guess, do you know what the critical water saturation there would be?
A. 100 -- that would be 100 RI. There's not a percent.
Q. Yeah, at 100 RI.
A. I have no idea what it would be. It doesn't matter what it is at a particular depth. It's the curve fit parameter that defines that curve. It's not a value at an RI. It's the curve fit parameter that describes the saturation found at each point on that curve. If I remember -- I don't remember the exact number for that. It seems like .78 or something like that, the exact number.
But that .78 doesn't plot anywhere on there. The .78 is the Sc parameter that describes the curve that goes through those data points. In the model, the Sc is not a discrete value. There's a

spectral model that exists all the way across there so that we can include all the different rock types in the analysis and we don't exclude anything.

Q. And so each of the data point plots, explain what each plot is.

A. Okay. Well, let's go to the grainstone. What we should have done that we didn't, and it's because it would have been useless for me because I can't see it, but basically the way the model was set up is we identified the rock class based on the Lucia-Kerans model. We gathered all the rock for a particular class or facies. We gathered all the samples that were identified with that facies and we plotted them on this cross-plot to see where they fell. And then we fit a line through that data cloud based on the Sc equation.

Basically, what we wound up doing is calculating an Sc for each one of those data points and then averaging it and then plotting that average Sc back to this equation to see was it a reasonable representation of the data points from which it was derived.

Q. I'm confident I didn't understand any of that. What I'm trying to understand, so if we have a dot that is on this, what is the dot?

A. It's a core point.
Q. It's a core point measuring --
A. It's the saturation from the core and then the resistivity index calculated from the porosity of the core and the formation water resistivity and the deep resistivity measurement recorded at the depth in which that core plug was recorded.
Q. And you can tell the commissioners that there's a great deal of uncertainty in the water saturation correction on this plot; isn't that right?
A. The water saturation correction? There's no water saturation correction.
Q. None of this involves any corrections to water saturations?
A. The corrected water saturations for my analysis go into this, yes.
Q. And there's a great deal of uncertainty in that correction to the water saturation from your analysis; isn't that true?
A. In my world, it was plus or minus 10 percent.
Q. And that's off of the core, which is --
A. Yes, that's based on my core analysis -- my analysis of how to correct the core data.
Q. With respect to the inputs on here, which of

these are assumptions or something that you've corrected as opposed to actual data measured?

A. The porosity comes from the core. The resistivity comes from a measurement from the log. What the assumption, the piece where there would be some interpretation would be the water saturation. Because what I'm doing is I'm correcting the oil saturations to the best of my capabilities, and then saying the water saturation is 1 minus my corrected oil saturation.

Q. Using this plot, if I'm understanding it, at, like, the mud dominated packstone, if you make the decision that the facies here is mud dominated packstone, what is the maximum amount of oil saturation that you could get into that particular rock facies?

A. It depends on what packstone resistivity that exists, and I don't know what that is.

Q. Is it Less than 20 percent?

A. Oil saturation?

Q. Yes.

A. It could be. I don't know. Like I said, it depends on where you are on that plot.

Q. By merely selecting a facies of mud dominated packstone, you can tell the commissioners that if you've selected that facies for a rock type, that can never have an amount of oil saturation that would exceed 20 percent; isn't that right?

A. I don't know if 20 percent is the right number, but that would be what the core data is telling us.

Q. And again, I'm trying to get this as simple as I can in my mind and maybe help some of the commissioners. By you selecting mud dominated packstone, here, based on your data throughout the entire San Andres, if it's mud dominated packstone, based on that facies, it can never go over 20 percent residual oil saturation, can it?

A. I guess that would be true.

Q. And we know that if it's less than -- if it's 20 percent or less residual oil, you exclude all of those oil volumes from your oil-in-place summation in this case that you're offering the commissioners, correct?

A. If it's less than 20, we did.

Q. And also, in terms of Mr. McBeath and his number, you know he relies on your oil in his numbers, correct, for his opinions?

A. Yep.

Q. And so here, simply by selecting a rock facies of mud dominated packstone, we know from that point on, it can never have more than a 20 percent oil saturation, and we know that you credit none of those volumes for the purposes of Mr. McBeath's economic work. True?

A. That's true. And it's based on Trentham's work.

Q. And here, we come back to the -- as we talk about uncertainty, we do not have core through the San Andres, we do not have pressure or sponge core in the San Andres at EMSU. You're working off of a gamma ray. You don't have spectral gamma to be able to parse out thorium, uranium and potassium.

You would agree with me that there is at least one rock facies of variance possibility here based on your lack of data? For example, moving over from a mud dominated packstone to a grain-dominated packstone?

MR. RANKIN: Objection. Asked and answered.

HEARING OFFICER HARWOOD: It's a long-winded sentence. Maybe you can break it into discrete questions.

BY MR. WEHMEYER:

Q. We've talked about the porosity of data here in terms of core. We have zero spectral gamma in

here. We have zero sonic inside the EMSU. You're not a geologist, but we've heard from Dr. Lindsay, who is a geologist.
What I'm coming back to is, you would at least give me that with this porosity of data, it's possible that you would be off by one rock facies? For example, what you classify as mud dominated packstone could be a grain-dominated packstone. True?
A. I suppose it's possible.
Q. At that point, the oil volumes here look much closer to the volumes that have been estimated by NuTech and by Exxon and by Ops Geologic; isn't that right?
A. I disagree. Those models are invalid. I don't agree with any of the saturations coming out with any of those models.
Q. What were some of the n values that -- I'm going to jump here for a moment and try to find a slide that I think -- are you looking on Slide 29?
A. I am.
Q. The red squares, will you tell the commissioners what the red squares represent.
MR. RANKIN: Mr. Examiner, objection, I guess. Dr. Davidson is color blind. So maybe we can figure out how to sort that out.

A. Those are just differences between 679 and RR Bell.

HEARING OFFICER HARWOOD: Okay. It's overruled. But can you see what he's talking about, Doctor, the squares versus the --

THE WITNESS: Well, there's a legend in the upper right-hand corner.

MR. WEHMEYER: Yeah, I didn't make the objection. I asked what the red squares are. I don't see anything that's not a red square on here.

And additionally, he didn't have any problems testifying about the slide when Mr. Rankin had the mic.

HEARING OFFICER HARWOOD: Overruled.

Do your best, Doctor.

A. Now, goddamn it. Look, there's blue circles or something down at the bottom, and then there's red squares. There's both colors on there. And there's a label up in the right-hand corner explaining what they are.

Q. And, again, I didn't make -- your lawyer made the objection. I thought you and I were tracking on red squares.

A. I can't see the colors, but I'm guessing the colors. But I can see squares versus circles.

Q. So if we take the very upper left one, tell the commissioners, what does that data plot represent?

A. That's a core point, and I guess that's a square, so that would be a core point for the EMSU 679 where we took the porosity and the saturation and the resistivity values and backed out what an n value would be to make this water saturation that was measured -- the corrected water saturation that was measured in that core match the core data.

So in other words, we're going through Archie's law backwards, knowing the saturation, knowing the n value, knowing the Rw, knowing the Rt, and we're back in solving that equation for n to see what the n value would be. And this is based on what Ops did.

Q. You solved for this n value, didn't you?

A. From the core data using the procedure they gave us.

Q. And weren't some of your n values here actually over 100? They were like 113, were some of your n values?

A. Yeah. And that's -- it could have been.

Q. And Ops Geologic, they used the variable n as well, right?

A. This is the calibration procedure that they told me that they used.

Q. My question is, it's just a yes or no, did Ops Geologic use a variable n? Yes or no?

A. Yes, they did.

Q. And their variable n's looked something from like 2 and a half to maybe 9, 10 at some places, right?

A. Yeah. And it's that line that's fit through the bottom of the curve.

Q. My question is, your n values, some of those actually went as high as 113?

A. That's right.

Q. Which doesn't seem reasonable at all, does it?

A. It doesn't, but that's the point. This is using the calibration procedure that Ops said they used. And we went through the exact same procedure calculating N for each core point to try to figure out what they did.

We took their model, which you're right, does have a variable m and n, and that came from the 746. We backed out what the N had to be for each of their saturations as they calculated, and we plotted it. And so it's a line on the bottom.

So what they did was, they did exactly

the same thing I did, they looked and they fit a line through the bottom part of the data to build their saturation model, their variable n model. Their variable n model is that bottom line.

My point is, that bottom line represents the highest possible oil saturations for a given porosity, and it ignores about 80 percent of the actual core measurements.

Q. So you built your own model and you came up with your own variable n values?

A. We didn't use N.

Q. Well, you have to have an N in your equation.

A. No, we don't. The equation is the one that's on the bottom left-hand corner of that plot we were arguing about a while ago.

Q. This is going back to our Slide 6, I think. What is the maximum oil saturation possible if Sc is .78? And I can go back to 6 if you need to see that.

A. I have no idea. It depends on what the maximum RI would be.

Q. What is the equivalent N for an Sc of .78?

A. I have no idea. I'd have to calculate it. We didn't use Archie.

Q. You understand that in their variable n, Ops

Geologic made adjustments to the core analysis, right?
A. I know that they made -- I know that they used a model to calculate the correction factor to correct the raw measurements to what they considered as the corrected.
Q. As there's measured oil saturation in the core, would you expect the lower oil saturations to be closer to accurate or the higher oil saturations to be closer to accurate?
A. I don't have any idea which ones are more accurate. Bleeding occurs from all of them. It's proportional to the amount of gas that's in the oil and the viscosity of the oil. So the relative bleed is probably relatively simple.
For example, if a core has 1 percent oil, it's not going to bleed as much as a core that has 50 percent oil simply because it's an expansion based on the amount of oil that's originally left in the core. So there's not more bleed at one level than the other unless there's more oil at another.
Q. As we come back to -- with respect to the porosities and permeabilities, you've seen that -- numerous ROZ discussion that oftentimes the highest oil saturations will, in fact, be found in the lower porosity, lower permeability rock?

A. Well, that could be the case if it was originally filled with oil and then displaced. For example, this is -- Seminole, the theory is that there was an oil column there, and then there was a trap breach, the oil-water contact moved up and displaced oil out.

And if you go back to my -- if that were the case, you could go back and look and see that saturations would be expected, that, in that condition, be somewhere in the 20 to 40 percent range. And the 40 percent can be associated with some of the good rock, and it can be associated with some of the poor quality rock.

Q. I want to put up a paper to see if you're familiar with this paper. This is Journal of Petroleum Science and Engineering by Bo Ren and Ian Duncan. Have you seen this paper before?

A. I have not.

Q. I'm going to get down to Section 4. Is that large enough for you to read it?

A. If you just tell me what you want me to answer.

Q. This study has not attempted to specifically model the Seminole Field. Rather, we have modeled the formation of a generic ROZ by starting with an oil-saturated reservoir. Its thickness is equivalent to the sum of the current SSAU ROZ in producing MPZ. Our simulations reproduce many of the features reported from the San Andres ROZ. The simulation results are consistent with an effectively steady state being reached, at least with respect to oil saturation, on a time scale of 50,000 years. It is significant that even after 1 million years of regional water flush, the oil saturation in several patches remains similar to the initialized values, .7 to .8. These patches are local areas of lower porosity and permeability. This observation is consistent with the observed presence of oil stains in the less permeable patches of the San Andres core samples.

You would give me that there is literature that would document the Ops Geologic conclusions that oftentimes some of the best residual oil saturations are actually found in the lower porosity, low permeability rock?

A. I wouldn't agree with that, because it's based on model results. And I would add that our model did a reasonable job of reproducing what they actually saw in the core measurements from SSAU.

Q. I intended to ask this earlier, I forgot.

On the core oil saturations in your analysis there, what was the pressure in the San Andres?

A. Well, we modeled the range and it was based on the available MDT data. Prior to the start of the waterflood, I believe the lowest pressure that we had was about 365 psi. And then we've argued about this point, whether it's San Andres or Grayburg or whatever, but I think the highest pressure in that interval was about 1264.

If we go back and look at what would the pressure be in the San Andres had there been no withdrawal at all, it seems to me like it's about 1700 psi, assuming it wasn't under pressure. So we modeled -- when I did the modeling, we modeled that entire range. I said, well, what if the 679 core had been depleted all the way down to 350, what would my viscosity B sub o bleed be?

Then I modeled all the way through that entire range, all the way up to -- assuming there had been no pressure depletion at all at the EMSU 679, which is not practical because it's up in -- it's just below the producing oil-water contact you'd expect at least there would be some.

Now, if you go back and you look it up, I believe it's the 211 data where all these MDT measurements were made, It's roughly the same depth equivalent to the 679 core. So it seems to me that the pressure range of 1265 to 364 would be a valid range. So that's where we did most of our analysis.

And so when we calculated the bleed and the expansion and all of the factors that go into that correction factor, we modeled it over a range from the 365 to the 1264 psi.

And then, just for an upside, because you guys weren't including uncertainty, I went ahead and modeled the point, assuming that there had been no pressure drop at all at the 679, which is 1700 pounds.

So then we derived a range of potential correction factors for each one of those conditions based on the B sub o, the gas content and the viscosity that was associated with each one of those pressures. And then we got a range of a final correction factor from 1.1 to 1.25 for the condition where we said 1265 is the maximum pressure it could be. But if we assume that there had been no depletion at all, it gave us the 1.3 correction factor.

Once you reduce the reservoir pressure and gas bleeds out of the oil, you don't get to go back and use the original B sub o to do your calculations, which I think a lot of people do. And that's an error.

Q. I'm going to try to use these slides to illustrate. As we talk about just your model, what I've endeavored to do here is illustrate your cutoffs.

In terms of your values, do I have this correct, that, for example, if we're looking at effective porosity on the bottom X, that if you get below .1 -- I'm sorry, .7, at that point, is this correctly illustrating that you would give zero oil volumes to anything below that 7 percent porosity?

A. We conclude that below 7 percent is non-reservoir rock, and we don't do any additional evaluation beyond that.

Q. Okay. And now I'm showing an Ops Geologic prepared slide to just illustrate in terms of plotting against the core measurements from the 679, the RR Bell, the 458 and the North Monument. Do you see at .7 effective porosity, we place the dash line that goes up that's on the X axis between the 6 and the 8?

A. I can't see it, but go ahead.

Q. Well, I want to make sure you can see it, because I just want to bring it back to just show the commissioners graphically kind of what we're talking about here by way of volumes. Can you see the cursor at least?

A. Yeah, I can see it.
Q. Okay. The cursor is at 7 percent porosity. And that would be where you cut off. Yes?
A. Uh-huh.
Q. If we move over to the left at 4 percent porosity, this would be the Ops Geologic cutoff, right?
A. Right.
Q. And then on the Y axis, do you see the permeability of 0.1?
A. Right.
Q. And you're saying you did not cut that off at point one, or you did?
A. Well, basically what we did, we applied I think -- the cross-plot is in my testimony. You can see what we did. It's one of the attachments in my original testimony.
We cross-plotted the core data from 679. And then we get a line to it, and then we selected 1 millidarcy -- 1 millidarcy, read over to the right, saw where the regression line was, read down, picked a 7 percent cutoff.
At that level, the way that we've drawn it, we would be excluding as many points that were permeability above .1 as we would be including that

were below. And that's -- you know, typically in the San Andres, a .1 millidarcy is chosen, and most operators use cutoffs in the 6 to 8 PU range. It's pretty standard in the San Andres. That's what people do to calculate pay.

Q. Earlier, we were talking about the core corrections and end values. And what I'm trying to do here is graphically illustrate. You would agree that the core has to be corrected, the core volumes of oil saturation have to be corrected, right?

A. Yes.

Q. And the correction here that Ops Geologic performed needed larger corrections down at the lower volumes of oil measured in core, smaller corrections up at the higher saturations of oil in core?

A. I don't believe that that's what was in their write-up. They basically said they used a rule of thumb based on the paper that was published, and I've got the same paper, and used that correction in order to do -- my view, it was one number. And if it's not one number, that's not what Mr. Birkhead stated in his write-up.

Basically, he said their low side was based on uncorrected measurements and their high side was corrected -- was based on the correction based on the rule of thumb that came out of the paper. I may have that wrong, but that's what I understood.

Q. And here, this is just a modification slide you had earlier. This is basically Ops Geologic demonstrating that if you're not filtering out the poor or the questionable data, you're going to have to have unreasonable n values that would get up into the 100 plus?

A. And maybe it was -- we didn't -- we didn't use those for anything in our analysis. What I was trying to understand is how they calibrated their model. And I see how the model -- and if that thing that has three lines on it is their model, then fine, they still are excluding measurements from probably more than half the core.

There's nothing magical about our points. We're just plotting the core data in terms of n that comes from backing n out of what it takes to match the core measurements.

Q. And again, what do your n values look like in your equation? I understand that you didn't come up with your own n, but in your equation, what did the n end up at?

A. I don't know. I'd have to calculate them because we didn't use n in our model. We used Sc in our model. So for each point, I can calculate an n, but that would only correspond to that RI and that porosity and that saturation. And if I moved a foot down, even though I was in the same rock type, I would have a different n, but I'd be on the same Sc value.

That's the beauty of that model, is I can characterize a variable n for all practical purposes with one curve set. And it is possible, I guess you could go through and calculate an n for each one. We didn't bother to do it because we didn't use an Archie model.

Q. Do you know approximately what n's would have been calculated -- I hear you on your Sc. Do you know about what the n's would have been?

A. They would probably have been, I don't know, 6 to 10, 6 to 20. I don't know. I didn't do the calculation. I'm just speculating based on gut feel.

Q. Let me go back to your presentation.

With respect to the residual oil saturations that you're reflecting here in Slide 10, would you just explain for grainstone, moldic grainstone, grain-dominated packstone, what are you demonstrating with this slide?

A. I'm just showing that based on the measurements that the Bureau of Economic Geology made, I think some of these were outcropped or some of them were Seminole. San Andres cores, there's a variety of sources for those. But these are average residual oil saturations to water that were reported for the rock types.

And I'd point out that, you know, you say, well, you're assigning something, and therefore, you're limiting it, I would point out that when we take our model and apply it at SSAU in the ROZ, we can reproduce this range of residual oil saturation.

So the model will work and provide the right outputs. And obviously, we're picking facies in the model and we've been able to verify it at Seminole, we've been able to verify it at Tall Cotton, we've been able to verify it at Maljamar.

Q. I guess what I'm trying to understand is that it's been the testimony of Goodnight in this case that the San Andres is an ideal place to inject saltwater.

In looking at the facies that you've actually selected for the San Andres and the critical water saturations that would be in there, maybe your Slide 6 helps illustrate it, but how on earth could you move water through that if your facies are correct and the water saturations are as high as you've represented in your testimony to the commissioners?

A. San Andres is full of karst.

Q. So your explanation for these rock types and the critical water saturations that you've come up -- and these water saturations you're up to are over 90 percent in the majority of the San Andres, isn't it?

A. Well, there's places where there are that I would call migration paths where that's not true. I don't know that San Andres ever had any.

The point is, the matrix of the rock in the San Andres would be relatively poor compared to the better quality rock up in the Grayburg. What makes the injectivity so high is the fact that we've had sulfuric acid going back and forth through there and the multiple meteoric paths -- pore volumes of meteoric water going through.

Q. So ignore the water saturations and the critical water saturation that you've come up with, and ignore the facies that you've assigned to these rock types. Your explanation for why Goodnight is able to inject into this is all on karsting as opposed to the rock type?

A. I think so. I think the karsting is the major component of why we're able to -- however, the rock -- the permeability -- like I said, the increased gamma ray content indicates an increased mud content, which indicates, indirectly, poor permeability.

So the rock type -- and there are high permeable grainstones in there. It's not that I've excluded grainstones and mud dominated grainstones from the Lower San Andres. They're there. All rock types are there.

As you move deeper in the system, you get more and more of the poor quality rock types and they're not going to -- they calculate as having very high water saturations.

So my conclusion is, there's not a lot of ROZ down there, or any at all. It's probably migration paths. And the injectivity that they're getting has to do with the karsting.

Q. So again, I'm just trying to figure out, with my simple mind, how two of these things can be at the same time. How is this rock type which you've selected as being either non-reservoir -- is non-reservoir even worse than wackestone? Right?

A. Well, we don't have wackestone in the model. But the non-reservoir would be the lower than 7 percent of the mudstones, the lime mudstones.

Q. Okay. The non-reservoir, is it between

wackestone and mud dominated packstone, or is it on the other side of wackestone?
A. Non-reservoir is anything under 7 percent, basically.
Q. Okay. Under 7 percent effective porosity?
A. Yes.
Q. And you've chosen that facies for the vast, vast majority of the Lower San Andres, Upper San Andres, all of it, haven't you?
A. I don't know that that's true.
Q. If it's your facies, how do you not know what rock is in your own model?
A. -Well, we can see that there's grainstones and mud dominated grainstones, or we wouldn't have -- that's where the oil saturations are. When we get into the high gamma stuff, that's poor quality rock, and that's going to be those poor facies.
Q. And isn't that, according to you, the vast majority of the Lower San Andres?
A. I don't know if it's the vast majority. It's certainly a good swath of the interval where you have high gamma ray that appear to me to be almost a carbonate shale.
Q. My question, isn't the vast majority of the Lower San Andres, according to you, the non-reservoir

rock?
A. I don't believe that's true. I don't believe I'm calculating low saturations in the vast majority of it. I don't know what the highest or what the major distribution of rock types in all of San Andres. Again, we didn't put out rock type curves, and we didn't do analysis on that.
Q. So the very first batch of questions I asked you was that your model is very facies-dependent. It comes down to the rock facies that you assigned and that you picked for the Lower San Andres? We talked about that?
A. That's true, but --
Q. And I'm asking --
A. I can get a grainstone and a very low RI and calculate a high saturation in the grainstone, and that's the best facies.
Q. Your model is very facies-dependent and facies-specific based on what you picked.
A. It's also resistivity-dependent.
Q. Now, in the Lower San Andres, the vast majority of what you picked in the facies is non-reservoir, or you don't even know?
A. I don't know what the vast majority is.
Q. How can it be that the facies is so poor

that it lacks such permeability and lacks such porosity that you're calling it non-reservoir and you've got it at nearly 100 percent critical water in some places, but it is so ideal for injecting saltwater that you --

A. Because it's karsted --

Q. How can those two things exist at the same time?

A. If you'll look at where the karsts are, they're in the high porosity intervals with low resistivities. And so what's happening is, the water is moving through there and what we're doing is we're creating bugs and we're connecting bugs. The bugs can be present in any of those lithologies.

And with the long-term passage of the meteoric water and the H2S, sulfuric acid, I'm creating permeability due to dissolution. And that occurred over long periods of time.

If you look where the EMSU is, it sets right on top of what Trentham and Melzer have described as the Artesia Fairway and the Capitan Fairway. Those two fairways coming together have pumped a bunch of water through there.

And if Lindsay is right and we had counterflow of H2S at the same time we had meteoric water, we've put sulfuric acid through that thing multiple times, maybe up to 20 times. And that's going to create the karsting system.

And that's why it's different. This thing is karsted to heck below that marker, but it's a different karst style than exists above the gamma ray marker.

Q. You just mentioned bugs. As I understand it, bugs are critters, fossils, that type of thing?

A. No. It's where you've dissolved out a critter or fossil and created a void in the rock.

Q. That happens at a surface, yes, a shallow water environment?

A. No, it doesn't. It can happen anywhere. It can happen anywhere that acidic waters move through. And that's the whole point, that acidic waters -- in the Trentham, Melzer and I'll say Alton Brown model, multiple flow volumes had been through there, and it was after the whole San Andres interval was uplifted and water came through. So it wasn't depositional.

The creation of the bugs in the water disposal interval occurred way after deposition, after the uplift of the Guadalupe Mountains and the exposure of the San Andres to meteoric fluid input. So it's a totally different system. It's not a shallow water environment.

Q. I'm going to move over now and talk about your idea of impermeable barriers. First, what's the difference between a baffle and a barrier?

A. I don't -- well, Ops described their low permeability/low porosity zones as baffles, which implied that they don't aerially go very far.

A barrier would be one that would exist where you could map over long distances.

Q. Okay. Well, I'm thinking of a baffle, like, in a truck, like a milk truck or a fuel truck. You're familiar with, like, a baffled truck that's moving liquids?

A. I have no idea what you're -- no.

Q. Baffles do not stop flow. What a baffle would do would inhibit, slow, impede flow?

A. Yes.

Q. Okay. And so you appreciate that there is a difference between a baffle and a barrier. Agreed?

A. Yes.

Q. Now, in terms of the -- I was reading your surrebuttal, and nowhere in there do you actually say that it is your opinion that there is an effective barrier across the EMSU. It is not the opinion of Netherland, Sewell to this New Mexico Oil Conservation

Commission that there is an impermeable barrier all the way across the EMSU between the Grayburg and the San Andres, is there?
A. My testimony is, as a result of the anhydrite layers that exist in that yellow highlighted interval, that the injection that is occurring below that yellow highlighted interval is isolated from the production that is occurring above that yellow highlighted interval.
Q. Let's take the highlighted interval. I would just like Netherland, Sewell to be on the record. Are you here under oath testifying for Netherland, Sewell that the yellow highlighted area, since we can't speak of Grayburg and San Andres and you don't know where the Lovington Sand is, is it the testimony of Netherland, Sewell here, are you swearing that there is an impermeable barrier across the EMSU at the yellow highlighted area? Yes or no?
A. I'm swearing that there's likely no communication through that yellow area.
Q. So if Mr. Rankin wants you to swear to this OCC that the yellow area here is an impermeable barrier, no fluids shall pass across the EMSU, for Netherland, Sewell, are you swearing to the OCC to that or not?

A. We haven't seen evidence that there's been water movement from the injection zone into the EMSU.
Q. Is your answer that you're unable to swear one way or another?
A. I guess that's true. But we haven't seen evidence of movement -- even though 120,000 a day is going into that interval below, we haven't seen evidence that has penetrated about that yellow interval.
Q. And so again, so that I've got one question on this, one question and answer, your testimony for Netherland, Sewell, you are not --
A. The testimony is not from Netherland, Sewell. The testimony is from me.
CHAIR ROZATOS: Doctor, wait for the question. I know you can anticipate it, but remember the poor, long suffering court reporter.
BY MR. WEHMEYER:
Q. All of the revenue that Mr. Rankin or his client are paying is not going to Dr. Davidson, it's going to Netherland, Sewell here. Yes?
A. That's correct.
Q. Netherland, Sewell is the firm engaged as part of this case; isn't that right?
A. I'm engaged as the expert in this case.

Q. As an employee of Netherland, Sewell?
A. Correct.
Q. If the Commission wants to know what the testimony of you, for Netherland, Sewell, is as to impermeable barrier at the yellow area, from your demonstrative Slide 17, you cannot testify one way or the other as to whether that is, in fact, an impermeable barrier all the way across the EMSU that does not allow fluid to pass. True?
A. I cannot. But I can say that the evidence --
MR. WEHMEYER: Object to the nonresponsive after that.
A. I can say that the evidence indicates that it is.
MR. WEHMEYER: Object to the nonresponsive after it is not.
CHAIR ROZATOS: Doctor, it sounded to me like a yes or no question. You'll have a chance to explain your answer on redirect if Mr. Rankin goes there.
THE WITNESS: He's got my answer.
BY MR. WEHMEYER:
A. It is not your testimony. True?
CHAIR ROZATOS: Mr. Hearing Officer, it is

getting a little heated right at the moment. We should probably take a short break, about 15 minutes.

And I want to remind everybody: Decorum. I have said this multiple times, we're not going to accept anything else but decorum. So everybody needs to be on their best behavior.

Mr. Hearing Officer, let's take a 15-minute break.

HEARING OFFICER HARWOOD: Okay. That's great. Let's call it 2:40 and be back at 2:55.

CHAIR ROZATOS: Thank you.

(Recess held from 2:40 to 2:55 p.m.)

HEARING OFFICER HARWOOD: I'll just remind counsel and Dr. Davidson, try to remember to wait for the end of the question and answer before speaking again. Think of it like a radio transmission, where people say "over" at the end of the presentation without the need to say "over." Thanks.

Go ahead, Mr. Wehmeyer.

MR. WEHMEYER: Thank you. I think I have less than five or six minutes of questions here, based on the last answer that I got.

BY MR. WEHMEYER:

Q. On the geomechanical studies, are you aware of any geomechanical studies that Goodnight would have

performed before commencing saltwater injection into Empire's oil unit?
A. I'm not.
Q. With respect to the frac gradient, any frac gradient studies, that is, at what pressure will existing fractures expand, any frac gradient studies?
A. I'm not aware of any.
Q. Do you agree that there would be a ROZ in the Upper San Andres?
A. Could be.
Q. Are you aware that Goodnight's Ryno well is injecting into the Upper San Andres, has perforations and injects into the Upper San Andres?
A. I'm not aware of that.
Q. And then these are two cleanups.
How did you calculate the resistivity of the water?
A. We used picket plot analysis.
Q. And at Slide 6 that I'm publishing right now, we've talked -- you made corrections to the data that's plotted on here?
A. To the --
Q. What -- the data plots.
A. Those are water saturations based on corrected oil saturations.

Q. That you prepared?
A. Yes.
Q. And so as we try to get back to your n, do you see that there are two curves drawn through the graph, and one is an n of 2, one is an n of 3.4?
A. Yeah. But those are just for display purposes. We did not use those.
Q. But as we talk about where n would be drawn through your plot, that would obviously be -- farther to the right would be a significantly higher n, wouldn't it?
A. If we had used n, it would be. We didn't use n.
Q. I understand you're saying you didn't use n. But we can see where n would be based on your work.
A. That's going to be higher than the 3.4.
Q. Can you just eyeball this? What about would n be based on your work?
A. Where?
Q. How about for a grain-dominated packstone.
A. I have no idea. It looks like -- if I just had to pull a number out, speculating, that might be a 6.
Q. How about for a mud dominated packstone?
A. Maybe an 8. I don't know. Again, I could

calculate for each one, but we didn't use it, so I didn't bother to go through that analysis.

Q. And what would n be for a wackestone off of here, just eyeballing it?

A. I don't know. Maybe 10.

MR. WEHMEYER: I'll pass the witness.

HEARING OFFICER HARWOOD: Okay. Mr. Moander, cross-examination for the OCD?

MR. MOANDER: I do indeed, Mr. Hearing Officer. Thank you.

CROSS-EXAMINATION

BY MR. MOANDER:

Q. Good afternoon, Dr. Davidson.

A. Good afternoon.

Q. This shouldn't take us very long, unless you shock me here. So you were deposed in this case; is that correct?

A. I was.

Q. And you also submitted rebuttal testimony in this matter on behalf of Goodnight, correct?

A. That's correct.

Q. And in your deposition, you had testified that you didn't have any opinions on communication between the San Andres to the Hobbs Channel to the Capitan Reef. Is it still the case you don't have opinions on that issue?

A. Well, I guess if I -- based on what I've learned, my opinion now is that water would most likely move to the east rather than to the west. But that's based on what I've heard and getting a little bit better understanding of the Trentham and Melzer model and the implications of potential water withdrawal -- oil and water withdrawals from the central part of the Central Basin Platform.

Again, this is simply an opinion, but my opinion would be the water would more likely move to the east than to the west.

Q. And you'd agree with me, then, that this is a new opinion not previously disclosed in any filings or during the deposition?

A. That's correct.

Q. All right. And then as to the particulars of your opinions, what you're testifying to us, if I understand it correctly -- well, actually, what was the basis for this new opinion factually?

A. Again, as I've learned a little bit more about the Trentham-Melzer theory and revisited some of the work that Arco did back in the early '90s, there was an establishment of tilted oil-water contacts in the middle of the Central Basin Platform, which the tilted oil-water contacts would imply a hydrodynamic gradient across the Central Basin Platform.

And since that time, I've gone and looked and looked at the withdrawals that occurred. And again, before waterflood and CO2 started in earnest on the top of the Central Basin Platform, roughly 7 billion barrels of oil had been produced, and who knows how much water had been produced from the central part of the Central Basin Platform.

And, you know, given that the Trentham-Melzer theory would connect the water in Southeast New Mexico to the Central Basin Platform, it makes sense that, you know, those sort of oil-water contacts become a little bit more credible to believe that maybe they do exist. And that would imply the movement of pretty large volumes of water from New Mexico into the Central Basin Platform in Texas.

Again, this is all opinion. I haven't done -- I'll tell you right now, I haven't done the hydrodynamic studies. I wouldn't even begin to try to do something like that.

However, I understand that Bob Trentham did do quite a bit of hydrodynamic work and concluded that quite a bit of water had moved across it. I think in his world, something about 15 to 20 pore volumes of water had moved out of New Mexico and into the Central Basin Platform. So if that's consistent in the tilted water context, or consistent, it would suggest that water is moving from west to east.

But again, am I an expert in that? I am not. Have I done the hydrodynamic work? I have not. That's simply an opinion based on the preponderance of the data I've looked at.

Q. And do you base this opinion on your background with knowledge, skill, experience, training and education?

A. That's correct.

MR. MOANDER: Mr. Hearing Officer, I'm going to go ahead and move to strike this opinion since this was absolutely not disclosed in any way, shape or form. I fleshed out that this has been developed outside the various deadlines in this case. This is 100 percent ambush testimony, which I am not in a position to refute at this point or cross-examine effectively upon.

HEARING OFFICER HARWOOD: Mr. Rankin.

MR. RANKIN: Well, I guess my understanding is Dr. Davidson was asked a question and he listened to all the testimony during this hearing and did some additional investigation. It wasn't within the scope of what we asked him to look at and so there are other witnesses who will be testifying on the questions that. Mr. Moander is asking. So I don't have an objection to striking the testimony.

However, I understand that it's based on everything that Dr. Davidson has reviewed and listened to today, to this point.

HEARING OFFICER HARWOOD: Well, this is a bit of a difficult ruling. On the one hand, you know, Mr. Moander, you asked the question, you got the answer. On the other hand, the witnesses said he's not an expert in this field. So it seems to me that the opinion that he gave at least deserves little weight. I'm not inclined to strike it entirely. I mean, you know, we can't unring the bell; what's been heard is what's been heard.

But I think the Commission can take into consideration that Dr. Davidson has self-admitted that this is just basically a lay witness opinion in an area calling for expertise that he lacks.

MR. MOANDER: Well, that's fine. I can ask him some other questions and we'll suss this out a little further then.

HEARING OFFICER HARWOOD: All right.

BY MR. MOANDER:

Q. So, Dr. Davidson, give me one moment here. So you'd agree with me you were deposed in this case on November 22nd, 2024?
A. Yes.
Q. And at that time, you were to render your opinions from examination from the parties opposing Goodnight; is that your understanding?
A. Yes.
Q. Do you recall testifying when you were asked specifically by me whether you had any opinions on the existence of migration of injection fluids in the San Andres into the Hobbs Channel of the Capitan Reef? Do you recall that question?
A. I do.
Q. And then you answered, "I haven't looked at any of that. You know, that's more of a geologist's bailiwick than it would be for me. And we have not looked at -- in fact, I haven't looked at any of the wells. I assume, from what little I do know, that would be to the east -- or excuse me, to the west of the EMSU. And I haven't looked at any of the data from that direction."
That was your answer?
A. That's correct.
Q. And then, let me share a little something

here. All right. Doctor, you recognize this document? Let me zoom in for you. My apologies, I forgot.

A. Yeah. That's my self-affirmed statement.

Q. Okay. More importantly, this is your self-affirmed rebuttal statement, correct?

A. Right.

Q. Is that right?

A. That's correct.

Q. And can you point to me in here where you recite anything you just told the Commission about your opinion on migration from the San Andres?

A. It's not in there.

Q. All right. Thank you.

All right. Turning back to your prior testimony, at that same deposition, do you recall that you testified you had no opinions on the broad-scale impacts of injection into the San Andres?

A. That's correct.

Q. And you also testified that you had no opinions on the effects of subsidence in relation into injection into the San Andres?

A. That's correct.

Q. And you also testified that you have no opinions on seismicity related to the injection at

issue?
A. That's correct.
Q. And I've got to ask this, since we've got a changed opinion here. Have you altered your opinions on any of these three topics since you gave that testimony and/or filed your rebuttal testimony?
A. I have not.
MR. MOANDER: All right. With that, Mr. Hearing Officer, I'll go ahead and I will pass the witness over to Mr. Beck.
HEARING OFFICER HARWOOD: Thank you, Mr. Moander.
Mr. Beck, for Rice Operating.
MR. BECK: No questions. Thank you.
HEARING OFFICER HARWOOD: I assume that it's Mr. Suazo for Pilot Water Solutions.
MR. SUAZO: Correct. Pilot has no questions.
HEARING OFFICER HARWOOD: All right. Instinct tells me that Dr. Ampomah may have some questions. I'll turn it to you first, Dr. Ampomah.

EXAMINATION

BY COMMISSIONER AMPOMAH:
Q. Thank you, Dr. Davidson, for your testimony.
I just want to clear this. So you are a

petrophysicist or you are an engineer? Just for my own clarity?

A. I do both. My Ph.D. is in oil engineering. I specialize in petrophysics and reservoir description for modeling.

Q. You know, let's say within the petroleum engineering discipline, you are more -- you have a lot of expertise in formation evaluation specifically?

A. Yes.

Q. Okay. I do have a couple of questions, so I'll try to go through that as quickly as I can.

If we can bring up the slides that you went through, that would be much helpful. Now, you showed a depositional environment. And I want to know, is this one for -- so that would be Slide Number 2. Would this one be for the San Andres?

A. It should be for either one, but it -- because the depositional environment is the same in the Grayburg and San Andres. It's just that the Grayburg that has spent more time in the high energy environment than it has the lower energy environment.

Q. Okay. Let's go to Slide Number 3.

Okay. So did you use a constant Bo for the estimation of the correction factor?

A. Well, again, I estimated a range of

correction factors based on my assumption of what the lowest reservoir pressure that had been obtained before the core was cut. But when I -- I used the constant Bo from the top of the core to the base of the core. But then I estimated a range of pressure, so there was actually a range of Bo values.

At the end of the day, I used an average correction factor that was kind of in the middle of the range, based on the uncertainty in the pressure range that existed for the pressure that was -- the lowest pressure that would have existed at the coring location at the time of the core.

Q. So was the correction applied to the core measurements?

A. Yes.

Q. Now, as you look at multiple conditions or situation at which there could be oil losses during coring, now, and based on all the discussions that we've had today, at least based on your testimonies, do you believe that the oil saturation that has been completed, or more or less even from the core analysis, could be underestimated?

A. Well, the analysis I did, I tried to include all the variables that would be involved in that correction factor, and I came up with a range. And again, the range that I came up with was about 1.1 to 1.3 correction factor, depending on the assumptions on how low the pressure had gotten. I settled for, I think, a 1.22 correction, which is kind of in the middle of that range.

And then, however, you know, if the reservoir pressure had not significantly fallen from original conditions, the correction factor could be the 1.3. And I testified earlier that that would result in about a 10 percent increase in saturations.

For example, if I had calculated a 20 percent oil saturation, then, you know, if the pressure had not fallen as lost as I thought it did, then it could be a 22 percent oil saturation.

Q. Now, you talk about -- so right on your number point, point 2, Number 2, you talk about, just getting to the end of the sentence, "...a pore volume reduction to account for reservoir stress conditions."

Can you discuss a little bit about the reservoir stress condition you are referring to here?

A. What I did is I went back and looked at a range of -- I calculated pore volume compressibility for a range of pressure drawdowns. And then, it turns out it's a very insignificant number.

But basically I said, well, if the

reservoir pressure had fallen to 300 pounds, what would the net effective stress be? And then I used the net effective stress in a model that we use internally at Netherland, Sewell to estimate what the pore volume compressibility was.

And then after I knew the estimated pore volume compressibility, I estimated how much the pore volume would have contracted as a result of the net effective stress. And I did that for the full pressure range that I looked at. And, in fact, they turned out to be relatively insignificant values, but I wanted to include all the possible mechanisms that would change the oil saturation when I did the analysis.

Q. You made mention of the pressure reduction. So did you see any pressure reduction in the San Andres?

A. The core -- again, these are just the corrections that I applied on the 679 core. And the problem is, I don't know for certain what the lowest reservoir pressure that was seen in the area that was cored prior to the coring operation, how far had the reservoir pressure been drawn down.

I did have some -- I think it's the EMSU 211, there were some MDT measurements at roughly the same depth, and the range of pressures that were exhibited in that MDT I think were 367 to 1264. I may have those numbers wrong. But I ran that full spectrum of possible lowest bottom hole pressures and calculated the B sub o, the R sub s, the viscosity, and then the correction factors for each one of those conditions. And that's where I came up with a range of a correction factor of 1.1 to 1.3 -- or 1.25.

Again, if I assume that there was absolutely no pressure drop in the San Andres and that whole core was at initial reservoir pressure and it had never been depleted, I'd get a 1.3 correction factor.

So that's the range of correction factors given the in situ conditions of the oil at the time that well was performed or the potential conditions that could be present at that location.

Q. So you said you looked at various ranges of pressures?

A. Yes.

Q. Now let me ask you. So, in your estimation, what is the initial reservoir pressure within the San Andres?

A. Well, I would -- the initial -- I would assume it would be the hydrostatic gradient. I think that turns -- I haven't got the numbers in front of me. It seems like it was about 1700 psi if I assume that the San Andres had never been depleted and it was at a normal hydrostatic gradient.

Q. So then, it is your testimony that the San Andres is not under-pressured?

A. I think the San Andres is under-pressured. For example, I think, if I remember right, and I may have these numbers wrong, but I think that the gradient that they're measuring in the injection zones is roughly about .38. If it were not under-pressured or somewhat depleted, I think that number would be more like .43 or .44, somewhere in that range.

So, again, I don't know what that -- the problem is, I'm not sure anybody knows what the initial pressure in the San Andres was before any of these fields were put in production, whether it was under-pressured or not. I don't see a reason it would be under-pressured, but maybe it was.

Q. You know, Dr. Davidson, I asked you about what the initial pressure in the San Andres was based on your analysis, because you talk about you looked at multiple pressure ranges, and then you told the Commission that it is hydrostatic, which is about 0.43 or .44, 1700.

Now, I asked you is the San Andres under-pressured, and then you are saying yes, so I'm confused. Can you help me out?

A. Well, the current measurements of what was purported to be the Upper San Andres in the MDT measurements -- and again, I don't know where the top of the San Andres is, so I don't know. I'm just going based on what was put forward by Empire. The San Andres interval would have had about a 1264 psi pressure. That would be under-pressured. They attribute that pressure as being evidence of flow from the San Andres into the Grayburg.

Now, the other piece of information that I'm aware of is that the injection -- the gradient in the injection interval, that disposal interval which is below that yellow band that you see on this figure, if we go down into what I'm calling the lower San Andres, which exists below that yellow band, the pressure gradient there today is, I think, about .38.

In my view, that would indicate that the lower San Andres is under-pressured. But what I don't know is has it always been under-pressured. What was it in 1921, before any of the production started? I don't know what that pressure was.

Q. Dr. Davidson, then my question to you is, do you believe that there is an uncertainty associated with even the correction factor that you calculated?

A. Well, the correction factor I calculated used the nearest pressure measurements to that well that I had at the time. And at that time, my conclusion would be that the San Andres around that well would have been at a pressure somewhere between 364 and 1265 or whatever that -- somewhere in that range, because that's the pressure measurements for the MDTs that I had available to me at about the depth of the core, at about the -- just before waterflood operation started.

And the B sub o and all that needs to be calculated at the lowest pressure that it was obtained prior to the initiation of the waterflood. Because the waterflood has the potential of re-pressuring the reservoir. I don't know if it did, but it has the potential of re-pressuring. But you can't put the gas back in the oil once it's escaped.

So you need to know what the lowest pressure was prior to the initiation of the waterflood at about the depth at which the core was recorded. And there was a range of pressures that were available, so I evaluated the full range. And those ranges would indicate that that part of the San Andres and Grayburg were reduced pressure from the hydrostatic conditions.

Q. So you utilized the same correction factor for the Grayburg and then the San Andres?

A. I used the average through that whole interval because I couldn't tell for sure what the actual pressure to use, what was the proper pressure.

It was somewhere between 364 and 1265. So I evaluated the full range. But for the corrections, I used something that was roughly in the middle of that range.

And, you know, the fact was, this evaluation of the correction factor occurred after I'd already done the original calculations. The original calculations were carried out using an Arco Oil and Gas Company Research rule of thumb that I had used back in the early '80s when we were evaluating core data to evaluate potential CO2 floods. That number from that analysis came out as 1.22.

If I take the average of all the measurements that I made from the 365 to 1264, you come up with 1.22. So I'm like, gosh, no matter what I do, I'm coming up with somewhere in that range. So I didn't go and change all of my corrections. I just said one of my original corrections seems to be in the right range. And that would be somewhere average between 365 and 1264, maybe 1,000 pounds or so would be that average that I assumed would have existed, the lowest pressure that existed in that cored area prior to the drilling of the core.

Q. Dr. Davidson, so are you telling the Commission that the correction factor that you actually used was based on your experience?

A. That's correct.

Q. And not necessarily based on the actual data from the San Andres EMSU?

A. Well, it was from the Grayburg San Andres pressure measurements. What I did was, because there was concern voiced by Empire, that was a very simplistic way to do the corrections, I went and did a full rigorous evaluation of what the possible range of those correction factors could be. And the evaluation of that full range came out to be 1.1. And if I assumed absolutely no pressure drawdown at all, the 1.3. And so the point is, I saw no reason to go back and change anything.

Then when pressed on well, what's the uncertainty, I followed the Ops model, and what Ops did is they decided that the biggest uncertainty was in the correction of the core measurements, and then they defined an uncertainty range based on the core correction factor. So I followed that same path.

In following that path, basically, you know, my correction factor range was from 1.1 to 1.25, realistically, for the conditions that were actually present. So I felt like the 1.22 that I had originally used was a pretty reasonable place to be, so I didn't make any changes.

So in answer to your question, yes, I used the experience of the rule of thumb, but I backed it up with a rigorous analysis that proved that that rule of thumb really wasn't a bad place to be.

Our core guy, Jake Rathmell, is probably one of the best core analysis people on the planet. And he developed that rule of thumb so that new engineers could apply it very easily and not have to go through all the rigorous analysis that I ultimately did.

Q. So has this been a normal practice in our industry that we always apply a correction factor to, let's say, a core measurement?

A. Yes, that's standard practice.

Q. And since you said it is a standard practice, did you check -- assuming Core Labs did perform this core analysis, did they apply the correction factor or not?

A. They did not. They don't report it. They report the saturations as measured.

Q. Okay. Let's move to Slide Number 4.

So there has been a lot of great discussion about the rock types. And then even looking at your cross-section right there, you've talked about the karst and then also the collapse.

My question to you is -- you know, and this will be the first question, you know, and I do have a series of questions on that.

You know, how does that impact CO2 EOR, assuming, let's say, with Empire's CO2 injection into the San Andres.

A. Well, again, I looked at the San Andres, the shallow part of the San Andres, above what I've defined as that gamma ray marker. I see that as a situation where the karst is certainly present, and I think they potentially would be much more limited in the aerial extent than they would in the Upper San Andres because they were created from exposure, surface exposure of the carbonate ramp at the ramp crest periodically in meteoric water, you know, rainwater basically, moving down through that and creating dissolution of the carbonate materials. So that's more of the typical karst that you see in a ramp environment.

And so again, this is my opinion. The CO_2 operation would be probably -- could be potentially advantageous in that environment because the karsting wouldn't have large aerial extents.

However, when I moved down into the San Andres Center, which I call the Lower San Andres, below that gamma ray marker, that interval appears to be, at least, to have been more affected by the massive water and CO_2 movement that Dr. Lindsay and Dr. Trentham have hypothesized.

And those karsts would be developed post depositionally at the time that the Guadalupe Mountains -- I don't know the proper geologic term for the uplift that occurred. But the rock had been uplifted and the San Andres was exposed at the surface, and you had meteoric waters moving through.

In Dr. Trentham's model, and it may be Dr. Lindsay's model, I don't know who actually came up with it first, but there was first a hot water -- geothermal water moving through there as a result of volcanic activity near the mountain ranges. And then there was a further uplift and shut that hot water off. And then you had cooler water that was just migrating in from the outcrops. And in their model, I think they hypothesized somewhere between 15 to 24 volumes of water had moved from that mountain range across Southeast New Mexico and into the Central Basin Platform.

Now, Dr. Lindsay has a theory that H2S was coming out of the oil, the Wolfcamp oil was being liberated and it was moving the other way. But the water would be moving downhill from the mountain range into the Central Basin Platform, and gas, because it's lighter density, would be migrating upward. So he has kind of a cross flow in that. And the commingling of that fresh water in the H2S would create a sulfuric acid. And I think that's a perfect recipe for karst.

In fact, I think that's the theory for the development of the Carlsbad Caverns, if I'm thinking properly, that the H2S and the meteoric water is what leached out Carlsbad Caverns.

And, you know, I'm unconvinced, you know, based on the -- you're looking at the gamma ray, seeing that there's smaller grain size material down in that Lower San Andres, the fact that they're able to inject on vacuum and they're able to inject thousands of barrels a day and over long periods of time, not seeing much of a pressure increase, that seems to me to indicate that the aquifer is very large and the permeability that allows that to happen would have to come from a karsting environment.

So, you know, and -- so I think that the Lower San Andres may fit the Trenton-Meltzer model extremely well. The Upper San Andres may or may not fit that model. It seems to be that the karsting is more localized.

But again, I haven't looked at all the data and that's just an opinion. I'm certainly not an expert on any of that, but I'm relying on the expert testimony I've heard to give you an opinion on the different styles.

Q. Well, so from the cross-section that we are seeing here, which I believe was Slide Number 16, so all the -- I believe, all the purple or the violet color, more or less, is showing the karst?

A. Right.

Q. Okay.

A. What this is actually showing is that the existence of what I think are bedded anhydrites through that yellow interval. And if you get below there, if you look at my computed well logs, you'll see that the porosities below that highlighted interval start getting very high.

For example, in the outcrop and in the cored interval, the average porosities of each of those rock types are in the vicinity of maybe 8 to 10 percent. So the porosities in the -- what Trentham and Melzer would call the main production zone up there, would be in the 8 to 10 percent range. The core data pretty much is consistent that you don't really have high porosities in that cored interval.

If you get below that yellow highlighted interval, you get into long intervals where the porosities start to approach 20 percent. And the other thing that you see in those intervals, again, if you look at my computed logs, is the resistivity falls to very low values. And those two conditions together indicate that there's quite a large mud volume in there. And the fact that they lose circulation as soon as they drill out of the bottom of that yellow interval and they lose returns, suggests that there's very high permeability down there, that there will allow a lot of fluid to flow, and they're able to inject 120,000 barrels a day or more into that interval, and they haven't seen any major pressure increase. To me, that suggests the presence of a karsting system.

Q. Well, so my question was very simple.

Within that yellow-shaded region, you're saying that there is a lot of karst in there?

A. There could be karst in that interval as well, but the anhydrites would be -- the anhydrites that would be indicated by those little flags would tend to isolate those intervals from one another, because the anhydrite is going to be impermeable. It's very -- it's impermeable. And if they're layered bedded anhydrites, they would present barriers to vertical flow.

Q. So those violet flags are not karst, but --

A. No. Those are the -- those are the bedded anhydrites, as I've interpreted them.

Q. But I thought one of your slides, you were showing that those are karst. You use that same color.

A. Oh, well, I apologize for that. Again, I'm colorblind, and maybe I choose these wrongly. But those flags in that exhibit are bedded anhydrites. Your question, could there be karst between those bedded anhydrites, the answer is yes, there could be.

But the major karsted intervals are those below that highlighted yellow interval, down in what I call the Lower San Andres, or the injection zone.

Q. So what will you term the yellow-shaded region?

A. In my view, that's a region that contains multiple potential vertical permeability barriers in the form of bedded anhydrites.

Q. So you think that the entire yellow-shaded region is anhydrite?

A. It's not anhydrite. The anhydrites are -- the bedded anhydrites are denoted by the little flags, and you see that they exist in all the wells.

Now, you can argue that, well, they don't exist -- you can't correlate them. And I would agree with that. You can't correlate one bedded anhydrite all the way across the field. However, there are enough of them that I think en masse that they provide a reasonable barrier.

Now, Mr. -- the counsel for Empire -- I'm sorry, I'm getting really tired. But counsel for Empire wanted me to say that I'm 100 percent sure that those are barriers, and I'm not. I don't know that I can map them all the way across.

However, the preponderance of the data, when you look, it's loss circulation, you look at the injection volumes. You look at the fact that we don't see direct evidence that major water is moving up that's impacting the Grayburg waterflood. In other words, we're not seeing that we're producing way more water than we're injecting, which would imply that there's major communication up.

My conclusion is, the preponderance of the evidence suggests that that yellow interval is providing reasonable protection between the injection zone and the waterflood operations above that yellow highlighted area.

And until we see evidence, concrete evidence, by way of pressure or the fact that we're producing more water than we're injecting, I'm pretty comfortable in saying that I think those two zones are isolated from one another.

Q. Okay. So you said that there might be some karst present within that yellow-shaded region. At the same time you do have anhydrite. So those are two things.

Now, is there a situation where, based on the karst, there could be a potential conduit between the Grayburg and then the San Andres?

A. There certainly could be a potential conduit. Again, I haven't seen evidence of it.

Q. Okay. So if you look at Dr. Buchwalter's model, Mr. William West really made it clear to us about the production history. So there was a map, there was a bubble map, that showed the oil production and then also water production.

So when you say that we do not -- you know, so the karst could be a conduit. Now, we are all petroleum engineers, so I want you to comment on the scenario where he also said this could be fractures that are existing, look at fractures that are existing. And then he utilized that in his simulation history matching effort.

So can you tell the Commission that that strategy that he used, looking at existence of fractures in the core, and then even you've also added karst to it, is there any strong evidence to suggest that what he did was wrong?

A. Well, I used to do a good amount of reservoir modeling early in my career. And to be honest with you, the reason I moved more into petrophysics and reservoir description is because I found that I could make a reservoir simulator to do dang near anything I wanted. I think your experience is probably the same. So what it told me was that we needed to spend more time doing the reservoir description before we started simulating.

And I guess the things that bothered me

a little bit about Dr. Buchwalter's model was that, for one, he modeled the entire San Andres interval, I guess, you know, from -- he moved the water contact down and then modeled everything under the water contact with, like, a 6 percent porosity and a single permeability.

Well, you can see -- again, it's not clear on this particular cross-section, but if you go back and look at the computed logs, and it doesn't matter whether you're looking at my computed logs, NuTech's computed logs, or Ops computed logs, when you get down into the lower part of the San Andres, the porosities are not 6 percent. You know, they get up -- you know, I don't know what the average would be, but you get porosities approaching 20 percent down there.

So the fact that he used a 6 percent porosity, in my opinion, too low of a permeability to represent the aquifer. If you choke the -- if you choke the aquifer with low permeability and you restrict its volume by using too small of a porosity, well, of course, you have to have a large volume to explain the pressure response you're seeing.

And I would argue that he might have been able to do exactly the same thing if he modeled what I call the Upper San Andres, above that yellow area, and modeled it with a high permeability. And edge water drive coming in, he might have been able -- and again, his was not really a simulation. I saw it as more of a large scale material balance model.

And I think you could probably build a material balance model that would explain the same thing, with not having to include the San Andres from the oil-water contact all the way to the Glorieta, and come up with an identical history match.

Now, I haven't -- well, you're going to say, "Well, have you done that, Dr. Davidson?" I'm going to tell you, no, I haven't. But I'm just saying, those are the things with the Buchwalter model that made me nervous, that I would have done differently had I built the description for it.

Q. Dr. Davidson, so my question was very simple, saying that -- my question was very simple. In our reservoir engineering principle, when we have a higher water production well localized, a higher water production well localized, similar to what was shown to us by Mr. West with that bubble map, I'm asking you a very simple question, is it typical in the oil and gas industry that with the knowledge of fractures from a core, and then also with the karst that you've even added to it, is it reasonable for a reservoir engineer to assume that there could be a localized either karst or fracture causing this high water production?

A. And I would agree with that. It's a reasonable assumption. Where I differ from Dr. Buchwalter is that I think that that water could be edge water coming in through a karsted system through a tortuous pathway from the edge. It could be water coming, you know, from the Upper San Andres at a localized area through a karst.

The other thing that nobody talks about that I have experience with, a lot of the early wells were open hole completions completed with nitroglycerin. And it's perfectly possible that water could be entering from the San Andres into those wellbores, and then migrating to the place where they saw the plumes.

I don't know that that's the case. I just know there's multiple possible scenarios that can explain those high water. They don't all necessarily have to go back to point out that the Lower San Andres is communicating all the way up through fractures or karst or whatever.

Q. Dr. Davidson, so I think you and I agree that that is an option. You know, and as a petroleum engineer, you have multiple options that are on the table. But when he chose that strategy, you and I agree that it's not wrong.

Now, my question to you is, you're describing to the Commission all the other potential options that could have happened. Why did Goodnight not perform a similar reservoir simulation model to debunk Dr. Buchwalter's scenario?

A. I don't have an answer to that question.

Q. Okay. Let's go to Slide Number 6. If we can go to Slide Number 6.

Okay. So there's been a lot of discussion on this slide as well. I want to ask you, can this approach, you know, using, let's say, a resistivity index and all of that, can that equate to the Archie's equation?

A. Yeah, you could get to an Archie's equation from that. The problem that you wind up with is, if I used Archie, every point on that cross-plot would have to have a different n value in order to return the proper saturation.

And the beauty of -- and I can't remember the gentleman from Schlumberger who designed this. But the beauty of this model is, with those Sc curve fit values, I could represent a whole range of

RI values with a curve fit model. It's simply easier -- it's easier to calculate.

Now, what I could have done, which would have been very tedious, is to go through and use the Sc value to calculate the n value, and then use Archie, the normal Archie's equation with the n value derived from the Sc curve fit, and I could have used Archie's model. Or I could use the equation at the bottom left-hand corner of that slide, which uses the Sc value directly with the resistivity index. So we chose to go that route because it makes the computations so much easier.

Q. It makes the computations so much easier. So your testimony is that the San Andres is an oil wet reservoir; is that correct?

A. I think that's correct. But the reason is not because of any particular attributes of the San Andres in and of itself. It's because of the relative ratio of asphaltenes to the lighter hydrocarbon components in the crude.

Most people believe in fingerprinting and showing that the majority of this crude probably originated in the Wolfcamp. In the Wolfcamp, the asphaltene concentration is relatively high. And when you get a situation where you have high asphaltene content, rocks, regardless of whether they be clastic or typical carbonates, tend to become oil wet. And it has to do with Van der Waals forces at the surfaces and the fact that the asphaltenes are polar molecules.

Q. So is it your testimony that the oil that probably might be in the Grayburg and then the San Andres is from the Wolfcamp?

A. That's what the general consensus in the industry is.

Q. Okay. So when Empire says that the reservoir might be mixed wet, what is your comment on that?

A. It could be mixed wet in a situation -- let's kind of drive the series of events. When oil is migrating, it migrates as though the rock is water wet; in other words, there's water on the outside, the oil migrates through to the point where it gets into a trap.

After it's trapped, and billions of years pass, there's plenty of time for those asphaltenes to be attracted to the surfaces of the carbonate grains. And it spreads wettability from oil wet to water wet. And most carbonates tend to be oil wet.

Now, a mixed wet condition can exist in

a situation where you have very high mud content, mud particle content. In that world, because the pore throats are so small and the Van der Waals forces that are attracting the polar water molecules, that those forces are so strong, that the oil can never penetrate in there to begin with. And that condition, the larger pores in the system would be oil wet and what basically would be the mudstone or the mud component that could still contain water. And that creates a very complicated conductivity environment.

And that's part of the reason, particularly when we get down to the mud dominated packstones and the wackestones, that that behavior becomes finally nonlinear, because you have a very complicated conductivity system with some of the currents passing through the mudstone and some of the currents trying to pass through the larger pores in the other portions of the rock.

Q. So, Dr. Davidson, are you saying that, let's say, you -- based on your analysis, you're saying that it is an oil wet reservoir?

A. I believe it's predominantly an oil wet reservoir.

Q. And --

A. And the -- okay. I'm sorry.

Q. Yes, sir. I'm just asking a very simple question.
And then, Empire is also saying that it could be a mixed wet. Now, based on the discussion, it sounds like you believe that this reservoir could also be a mixed wet.
A. There's portions of it that could. The portions that contain very high volumes of mud-sized particles, you could have a mixed wet system. But, you know --
Q. Okay. So if you have a mixed wet system, now what are the assumptions that you utilize on this particular slide?
A. Well, again, I'm taking the saturations as they appeared in the core and I'm plotting them versus the resistivity index. And I'm fitting the model by rock type to each one of those clusters of data.
So I really wouldn't -- the wettability, while, I believe it's an oil wet reservoir -- and arguably, one of the methods that -- for example, one of the methods that's used to identify the presence of an oil wet reservoir is to create a plot just like this. And this comes from Jerry Lucia and comes from George Asquith and it comes from the folks from Schlumberger. When you make this cross-plot, if the

majority of the data falls above the n equals 2 line, then you conclude that the reservoir is oil wet. That's one of the uses of this cross-plot in the industry.

But regardless of the wettability, I've taken the core data, corrected it, plotted it on the cross-plot and I've fit a model to the data, the corrected core data. So the model is going to be applicable whether or not it's fully oil wet or partially water wet or mixed wet or whatever, because I've built a model that's calibrated to the actual core measurements.

Q. But wasn't your testimony to the Commission that it doesn't necessarily matter the type of wettability, your analysis is still valid?

A. That's correct.

Q. Now, the m and n, more or less, inherently, some way, somehow can be within this equation?

A. Yeah, you could turn this into Archie if you want to.

Q. And is it your testimony that the wettability doesn't impact the rock type?

A. No.

Q. Not at all?

A. No.

Q. Okay. So on this particular map -- on this particular plot that you're showing us, can you identify oil saturations above 20 percent?
A. Well, yeah. They would be a little bit difficult. Whoops, they just lost it.
Q. Yeah, we can just draw a line --
A. But, yeah, you just draw --
Q. Yeah, just draw a line.
A. Yeah. It's a long scale, so it's not trivial. It's .1 on the left, and so it'd be probably a little -- see the .69 down there at that green arrow? It would be -- the 80 percent would be somewhere to the right of that, between that .69 and 1. So obviously, I'll -- it may be that where you've got the cursor.
Q. So when we look at that -- and then you're saying that these points are oil saturation points from the EMSU 679?
A. They were above -- they were above 80 percent water saturation or they wouldn't be plotted on there, on the points above that line.
Q. Now, I'm just asking you that, these points that you are showing us, whether it's a complete point or not, these are all actual core measurements from the EMSU 679 well; is that correct?

A. That's correct.
Q. And we've established that there are oil saturations above 20 percent, as you've plotted here; is that correct?
A. Yes.
Q. Then tell the Commission why you say that there is no ROZ.
A. I didn't say there's no ROZ in the Upper San Andres. Again, I have -- I may have a little bit of difference of opinion from Trenton and Melzer. When I look at actual ROZs that have been established, I see a pretty repeatable profile in saturations for the top of the ROZ to the bottom. And I don't see that nice straight line at about 40 percent in the 679 or the RR Bell data.
That doesn't mean that it's not an ROZ. It just means it doesn't have a profile that matches what other ROZs have.
Again, I would be perfectly happy if Empire went in and installed a CO_2 project in that Upper San Andres and made money with it. It would be great.
My contention is that the injection operations that are occurring below this yellow band are not likely to impact it.

Q. Well, so, you know, let me pick up on your last point that you made, your last statement. You said that it would be great if Empire can go in there and do a CO_2 project up in the Upper San Andres?
A. Yes.
Q. Is that not what they are requesting from the Commission?
A. What -- what -- yeah. The problem, as I see it, is they're trying to shut down injection operations in an interval that, in my opinion, is not affecting their potential ROZ development in the Upper San Andres.
I think both companies can continue on and not interfere with one another. And at minimum, we could probably install some sort of a monitoring process to ensure that they're not interfering with one another and come up with a way to handle it if there is -- if communication is established.
But I don't see anything right now that's preventing Empire from moving forward with the development of the ROZ in that upper interval. And I don't think that the injection operations for all this little yellow band are necessarily endangering that project.
Q. Well, Dr. Davidson, so is it your testimony,

are you concurring with Empire that at least there is an ROZ in the San Andres?
A. I think there's probably -- there's indications there's one in the Upper San Andres above what I call the gamma ray marker.
Q. So is it your testimony that -- you know because Mr. McBeath was saying -- he used the word -- he used a statement called -- I forgot. He had a -- he used "alleged." Thank you. Alleged --
A. Alleged resources.
Q. -- ROZ. He said alleged ROZ.
A. And in my understanding, Mr. McBeath's testimony was concerning the interval beneath this yellow -- in the San Andres beneath this yellow band.
Q. I don't remember --
A. In fact, the testimony was he went in and took the San Andres interval above that yellow band, calculated the oil saturations in there and came to the conclusion that the economics may be questionable. But then when questioned on whether or not there was an ROZ that existed all the way down to the Grayburg, I think he coined the term "alleged resources" for that. And we're talking about two different San Andreses, in my opinion.
Q. Well, so, I mean, we're all here. I don't

think Mr. McBeath showed us even the anhydrites, the karst, the yellow-shaded regions that you are referring to. I mean, this is the first time I'm seeing that. So he said there is an alleged ROZ.

But based on the discussion that we're having now, it sounds like you're saying that at least there's this ROZ in the Upper San Andres.

A. I think there very well could be. But again, I have a different opinion. I think they look more like migration pathways. They may or may not be aerially continuous. But I can't say with certainly they're not there. They've seen residual oil in the two wells and cored into that Upper San Andres.

And, again, if Empire feels strongly about going for it, I think they should go for it. But I don't think the injection operations deep are going to impact it. And I think the Commission could probably put in place some monitoring protocols to make sure that they're not interfering and come up with a game plan for how to move forward if interference is ever found.

Q. So, Dr. Davidson, on your cross-section that we've seen there, using the yellow-shaded region as your reference, where is the Upper San Andres?

A. Well, again, I don't know where that top of the San Andres pick is. I don't know, and to be honest with you, I don't know whether anybody does. But it would probably be this little region right in the middle.

MR. WEHMEYER: For record reference, indicating about four inches above the yellow deal.

A. Yeah. And, again, I don't have the top -- or is it -- I don't think I have the tops.

But this interval here is probably the Grayburg. This little interval right down here would be what everybody, in my view, is calling the Upper San Andres. The ROZ, I think, resides along this interval. And then we have a long interval that is -- this high frequency interval, where I think we potentially have the bedded anhydrites.

And then the injection operations are occurring down here, and then that's the 700 TBD, below this interval. And the fact that we can drill through this thing, move circulation down here, we can inject down here for long periods of time, you don't see pressure increases, which indicates it's a very large aquifer, and thus far up here, I haven't seen concrete evidence that significant volumes of water are moving up, such that the produced water volumes exceed the injected water volumes.

So again, I'm in the position to -- and I'm just saying the preponderance of the evidence at this point that I can see indicates that they are two different systems.
Q. So, Dr. Davidson the yellow region.
A. Yes, sir.
Q. Now, the anhydrites that you've picked, do we have any core data supporting that or mud log data supporting that?
A. Anhydrites show up at the mud logs, but they're not going to be able to tell whether they're bedded or not. That conclusion comes from my viewing of cores, particularly in the Levelland Slaughter area where you see this, the combination of elevated gamma ray, the low porosity and the high grained and high bolt densities became the presence of anhydrite.
And Jerry Lucia developed a cross-plotting technique to identify bedded anhydrites. In those intervals, they fit the fact that there's elevated gamma ray, they fit the fact that the density neutron cross-plots indicated the presence of anhydrite. The mineralogy model suggests the presence of anhydrite. And I've seen this log signature in places where core data exists and bedded anhydrite have been observed.

Have I seen core in EMSU in the San Andres that shows bedded anhydrites? I have not. This is just based on my experience.

Q. So you've not -- and even based on the cross-examination, it sounds like you cannot put on record that you believe that this is a barrier to, let's say, flow?

A. I believe it's a barrier to flow. I can't say with 100 percent certainty that every one of those is a bedded anhydrite.

Q. And you also testified that the Commission doesn't need any additional data.

A. I don't believe so. I think that there's enough data from the injection, the lack of interference, the loss circulation that there's not communication between the two. Again, I'm just looking at the preponderance of the data that I see.

And I would argue that it may be very difficult to get reasonable core data down there because of the loss circulation issues.

Q. So let's go to Slide Number 5, right here. So this is the rock type analysis that you performed; is that correct?

A. Well, this is based on the outcrop analysis. These were averages of the petrophysical properties for the different rock types present. What I was trying to show here was there's not a very big porosity variation, but there's a big permeability variation. And it's therefore important to try to identify the different rock types in the petrophysical parameters when you're doing the analysis of this type of ramp environment.

Q. So did you utilize this rock type that you've developed based on outcrop data for the subsurface analysis?

A. Well, the process was this. The Bureau of Economic Geology was tasked with developing a model that could be applied in a carbonate ramp environment. And they identified the major rock types that are available or present in a carbonate ramp environment.

Then what they did, they went to the outcrop, they dug down into the face of the rock outcrop to get the surface weathering features off. They collected core samples out of the -- they identified the rock types present, calculated or obtained core samples out of the rock type. Then they took those core samples and they cross-plotted them by facies type, for example, grainstones.

They cross-plotted all the grainstones together, across the permeability cross-plot, and they defined a region on that porosity permeability cross-plot that is associated with the grainstones.

Then they did the same thing, for example, for the mud dominated packstones. They collected several samples of mud dominated packstones. They plotted them in the cross-plot. They found that they existed below the grainstones in the translated, you know, density neutron cross-plot trend. They did the same thing for each one of them.

And then they went through and they said, okay, for each one of these -- Jerry Lucia calls them classes rather than rock types. But for each one of these classes, I'm going to determine an average value, a standard deviation, and I'm going to create this cross-plot model so that anybody can take core data, put it on this cross-plot, or even identify the region associated -- the porosity permeability region associated with each of these different rock types, and they can make a preliminary estimate of what the rock type is.

So I did the same thing with the EMSU 679 data. I found all the -- and I took Jerry Lucia's cross-plot and I plotted all the core data up so I could -- all the -- for example, there's a band of data that represents the grainstone that they found in the outcrop.

I took all of those grainstones, the core samples, that fell within that grainstone cross-plot region, then I plotted them on that RI versus Sw plot, and I did a curve fit of that Sc value through those grainstone values using the log saturations.

That provides a reasonable estimate of how a grainstone would behave as a function of RI, given the corrected oil saturations and water saturations that were measured in the core. And I used that model rather than an Archie's model because it's much easier to use than trying to come up with a variable n model.

And I tried to demonstrate that the variable n model is somewhat difficult because for a particular porosity, there's a variety of n values that can occur, so then you have to go and you have to do the same thing. I could have done the same thing with Archie, granted, if I wanted to go to the trouble to come up with that n model for each rock type. But this Sc model is so much easier and faster to calibrate. I used this Schlumberger model because it's simply much easier to use than the Archie in this environment.

Q. So, sir, it was a simple question.
Let's go to Slide Number 11, and I'll try to wrap up here. So here, I'm asking you, do you see any oil saturation within the San Andres?
A. In the San Andres, as it's defined here, it's below that region of the high frequency. If you can see -- I can't see the depth. Move your cursor up to that gamma ray, maximum gamma ray.
It looks like it's about 525. So that interval from 525 down, go down about an inch on this thing, that's that high frequency interval. And I think this is one of Preston's picks. He's picked the San Andres to correspond to the interval that's the injection zone. Again, I'm not going to get into the pick argument. That just happens to be where this San Andres is.
If you go down, you'll see in the oil saturation track, periodically I do calculate relatively high saturations. I mean, there's some up to 30 and 40 percent in there. They show up periodically up and down the system.
So yes, there is oil down in there. They tend to be associated with some of the lower gamma ray readings. And that makes sense because the lower gamma ray readings, down there in that yellow

San Andres interval, correspond to the grainstones and the better rock types.

So yes, there are grainstones and better quality rock types all the way through the San Andres. If you get deeper in the system, you see the gamma rays starting to get higher and higher. That's indicating a higher mud content.

But when a gamma ray does clean up and the resistivity is high enough, we do get oil saturations down in the San Andres. The problem with that is -- I mean, so yes, there's oil in the deeper San Andres. The problem is they're separated by hundreds of feet. They don't necessarily have the profile.

If you look on the right of that diagram for the Seminole San Andres Unit, at the water saturations in the right track there, you see that there's kind of a wall of 40 percent, 45 percent saturations from the top of the interval to the bottom of the interval.

When I'm looking at the oil saturations, for example, at the bottom left of the EMSU 746, they don't really have that flat profile. In my view, those are more indications of abandoned migration paths. I may be wrong on that, but in my view, that's what they are. They certainly don't seem to represent the profile that I would associate with an ROZ.

The other problem is that the majority -- when I do calculate the presence of oil, the majority of it is less than 20 percent. And Dr. Trentham excludes intervals with less than 20 percent. Ops excluded intervals with oil saturations less than 20 percent. We excluded oil saturations less than 20 percent.

And if we go over here to the right, and let's go up to what's the MPZ in the SSAU, can you put the cursor up there for me, that interval, that's been CO_2 flooded for over 40 years and the oil saturations don't -- rarely exceed 20 percent.

So to me, that tells me CO_2 is not going to be effective at oil saturations at 20 percent or less. And, you know, Dr. Trentham agrees with me on that. And so, in my view, counting the oil saturations less than 20 percent down there and including that as potential economic oil is not prudent.

There are some intervals, and if you look down there, particularly at the bottom, let's go down to the bottom on the 746, there's intervals up there that are 30 and 40 percent oil saturation. But they're very thin and, in my view, they're probably not ROZ. They're probably migration paths.

But there's just not going to be enough down there, at least in my opinion, to be economically attractable to go after. And if they're migration paths, they're not going to have any aerial continuity. And if there's major karsting down there, it's going to steal the CO2 and prevent it from being able to displace any of that in the first place.

Q. So, sir, you know, as a petroleum engineer, and based on your extensive experience, I want to ask you, what is the typical residual oil saturation to CO2 injection?

A. It might be about 20 percent.

Q. Residual oil saturation --

A. To CO2, yes. Now, in the lab, they can get it down to about 12 percent. But the problem is, in the lab, you have a confined tube, and the CO2 can escape.

In reality, when you have an unconfined CO2 injection, dispersion will drive a bunch of that CO2. Unless it's confined between the very good barriers, dispersion will drive it out and you don't get a nice sweep across the entire interval.

And, again, I go back. The interval in

the MPZ on the right has been CO_2 flooded for 40 years, and there's very few saturations, less than 20 percent. So I think that's kind of the bottom. In a practical field operation, that may be the bottom. And it's not because the CO_2 couldn't do it more. And in a core plug, you can get it down to maybe 12 to 14 percent, but in the reservoir, dispersion kicks you out where you can't really get it that low.

Q. Just help me understand why in our industry, where, let's say, oil saturation, irreducible oil saturation to about -- let's say residual oil saturation to about 27 percent, 25 percent is where we kickstart CO_2 injection.

A. And I believe that -- and what you find is that you get a lot of the oil between 20 percent and 27 percent. And if you've got a lot of area, that's turned out to be quite a bit of oil.

Q. Well, I'm not sure any company will go in and say that I do have movable 7 percent saturation points that I'm going to throw in huge amount of capital to proceed with the CO_2 injection.

A. I wouldn't put a large amount of money into doing anything when the saturations are less than 20 percent, because I don't believe it's been demonstrated that you can reduce the saturations much lower than 20 percent. And I think Dr. Trentham would agree with me on that.

And what they -- and I actually did the analysis. I mean, it's in my write-up. I went back and looked at Seminole. Seminole's very well defined in their CO_2 project. And I went back and I did the analysis, and I said what was primary, what was secondary?

I calculated in the main production zone what the residual, average residual saturation post-secondary recovery was, and then I looked at what happened, what the projections were going to be post CO_2.

And, basically, I found that if I took the residuals that were present at the end of the waterflood and reduced those residuals down to the 20 percent, I was able to match the production, the CO_2 performance that they actually obtained.

And that was a method, a secondary method, and it's in my rebuttal testimony. Because I got such pushback on this 20 percent, "Why are you excluding the intervals that have 20 percent oil saturation? They're going to sweep, too."

I'm like, there doesn't appear to be any indication of that. So I went back and looked at

Seminole, and when I did the analysis, I said -- you know, I showed that, yeah, you could -- the average -- post waterflood, the average residual is about 35 percent. If I take that 35 percent and reduce it to 20 percent, I could reproduce the recovery that occurred from CO2.

Q. So, sir, when we say that typical -- based on Steve and then Bob's testimony, did you find ROZ more or less from 20 percent upwards?

A. Yes, sir.

Q. So are you saying that that is a wrong definition?

A. No, I think that's a perfect definition. They're smart enough not to include the intervals with oil saturations below 20 percent and their in-place estimates when they calculate the ROZ potential.

Now, I'm not saying that it -- don't calculate -- don't count from 20 down. If an interval has got 35 percent oil saturation, you count the entire oil saturation.

I'm just saying that if an interval doesn't have at least -- it doesn't exceed 20 percent, it's probably not going to flood economically and it shouldn't be calculated in the in place.

The recovery factors are based on the

in-place estimates, right? And if you look at Seminole and you look at the in-place estimates on the intervals above 20 percent, and you calculate what happened, what you find is that they got roughly 25 percent of the oil that was in place in the intervals that exceeded 20 percent oil saturation. That recovery factor goes with that oil in place.

Now, if we had included the whole interval, all oil is oil, it's all oil in place, then that recovery factor would probably fall down to 5 or 6 percent, which is fine. But you've got to understand that recovery factor and in place are implicitly tied together, you cannot separate them. And if you're going to include oil that's not going to move, then you've got to reduce the recovery factor to account for the fact that it doesn't move.

And as a result, Dr. Trentham and Melzer have basically said 20 percent and above is what we need to consider as intervals that contain ROZ that's commercially retrievable.

Q. You also talked about using a 7 percent cutoff. I mean, you said that is an industry practice. Is there any reference to a carbonate where 7 percent is used as a cutoff, any reference that you can share with the Commission?

A. You could probably go up and look at the Maljamar data. I think they use 6 percent there. The industry standard, to my understanding, is typically for carbonates on conventional analysis, conventional waterflood, primary production. You usually use a 1 millidarcy cutoff. And then you look at your porosity perm, because we can't calculate permeability with well logs. Some people think they can, but we need -- in reality, we can calculate porosity, we can calculate saturations, if we have core data, we can build a porosity permeability cross-plot.

And then we say, okay, let's look at down there. And in most cases, you say, okay, for an oil, we'll use 1 millidarcy and then I'll curve fit that line, and I'll say, okay, at this point, I've got as many points that I'm excluding that are above 1 millidarcy as I'm including that are below 1 millidarcy. So I'll use that porosity cutoff in lieu of a permeability cutoff and I'll say that porosities below that interval or that level are non-reservoir.

I didn't want to be that strict, so we actually went -- because, again, and you made the point, because this is gas injection and gas can move in places that liquids can't, I said, okay, let's use a .1 millidarcy cutoff. And that .1 millidarcy cutoff with that 679 data indicated a -- I mean, permeability -- a .1 millidarcy permeability cutoff corresponded to about a 7 percent.

And I went and talked to Bill Knights, who is our geologist, and I said, "What are people using for cutoffs in the San Andres:

He said, "Well, generally, somewhere between 6 and 8 percent."

And I said, "Fine. We're right where everybody is."

So I was comfortable with that and I was comfortable with it because we allowed the fact that not using the traditional 1 millidarcy, going to a tenth of a millidarcy, because we were evaluating a potential CO2 operation rather than a waterflood operation. So it's a little bit more inclusive. I felt like I was being generous. And I'll say --

Q. Okay?

A. -- Empire and those folks are going to say, "My, God, you're killing this. It's a 4 percent." You know, and there's different opinions on that. And believe me, as a petrophysicist for a reserve consulting company, cutoffs come up every day and I get hammered. I've never been right in my 45 years on a cutoff with anybody else.

So I always argue it needs to be different than what I've selected. So, you know, I've got a pretty think skin on that. I get criticized regularly for my cutoffs.

Q. So, my question to you was, do you have a reference, a documented reference --

A. Well, I can --

Q. -- to show the Commission?

A. I guess I can show you where -- for example, at Maljamar, in their waterflood study, where they did the pressure core, their oil-in-place estimates are based on a 6 percent cutoff, which -- but, on the other hand, that's better quality rock in the Upper San Andres using a 1 millidarcy cutoff.

So, you know, I would say that I'm even more aggressive because I'm using a tenth of a millidarcy in the porosity that goes with that?

I can show you that reference. I've got it with me. We can take it out and look at it, if you want to see it.

But as far as are their general references that say what the cutoff should be, I haven't seen it. And, if there are, I haven't found one that I can show you.

Q. Yeah. So, I was curious, during the cross,

you said in the industry, we use 7 percent. So, I was curious to know that.
Now, my last question to you, hopefully to be the last one, it depends on how you respond to it, are you familiar with the water withdrawal wells within the vicinity --
A. Yeah.
Q. -- of the EMSU?
Now, so, you do have excessive high volumes of higher salinity water injected by Goodnight into the San Andres.
A. Right.
Q. Don't you believe that, at some point, that injection is going to impact the water supply wells, where you have higher salinity with different types of TDS, different types of, let's say, composition withdrawn and utilized as a waterflood in the Grayburg? Is that not going to impact the activity in the Grayburg?
A. Well, again, I haven't looked at where the water supply wells are completed. I would have to think that if the water supply wells were all the way down into the Lower and you continually inject isolated into the Lower San Andres, that you're -- potentially there's going to be communication.

However, the other option is to take water out of that shallower interval above what I call the gamma ray marker. Again, those operational considerations will have to be considered as -- you know, I guess at the end of the day, I think both of these companies could get along just fine and an equitable solution to this problem can be found.

And it may mean that different water supply wells have to be drilled other places. It may mean that they have to install pressure monitoring and all those sorts of things. But I don't see any reason why both of these projects can't go on. And that's just my personal opinion. Nobody from Goodnight talks to me about this stuff. I'd just be looking at the practical aspects and wanting the best for everybody.

I want everybody to succeed. Our company wants everybody to succeed. What we try to do is identify risk and help people make the best decisions possible. And when I look at this, I think, guys, there's potentially some great projects here for everybody.

You know, the disposal -- disposal is valuable to the producers in New Mexico as well. They've got to have somewhere to put the water they're producing or they're going to have to shut wells in.

You know, there's a lot of people, a lot of moving parts in this thing. And in my view, it's one of those deals that everybody can get along, we just need to figure out how to work together on this.

Q. Well, you said everybody can get along. So you are not aware of any discussion between Goodnight and Empire, where Goodnight is proposing to Empire that just focus on the Upper San Andres and let us do our own thing in the Lower San Andres.

A. I wasn't involved in any of that, so yeah, I'm not aware of that.

Q. You know, so based on what you discussed, then could there be a scenario where the Commission will say that, "Okay. Let's give Empire the time frame they are requesting for probably two or three years and let them do their characterization analysis and come back to the Commission and prove to the Commission that 'we drilled, we saw it, and it's recoverable'"?

A. That's fine, but I'm not sure that curtailing injection for the Goodnight wells during that process is necessary.

Again, I think Goodnight could go -- if they wanted -- I mean, Empire, if they wanted to go ahead and try to do the work to establish an ROZ in the Lower, in my view, there's nothing right now from stopping them.

If it's truly immobile oil, you know, in other words, it's not mobile, the injection operations aren't going to move it. And you could drill and core it and see whether or not the ROZ profile exists. I don't think there's anything stopping them from doing that. For whatever reason, they're hesitant to make that jump.

And again, when you look at the big picture of everybody that's depending on this disposal and the fact that it's an ROZ and the oil is not mobile, this is just me, I don't know why you couldn't go out and drill a well if you wanted to do it and core it right now. Because the injection is not moving the oil anywhere. What you're interested in is, is there an ROZ in that lower section.

You know, I don't see any reason why they couldn't do that. And I don't see any reason why injections couldn't continue while they do it. And I don't know why they're not doing it. You'd have to ask them that.

But I'm looking at it, and it's like, I don't see any real reason to change anything until there's definitive evidence that you need to.

COMMISSIONER AMPOMAH: Thank you, sir, for testimony.

HEARING OFFICER HARWOOD: Thank you, Dr. Ampomah.

Mr. Lamkin, questions for Dr. Davidson?

COMMISSIONER LAMKIN: Yeah, I have a couple.

EXAMINATION

BY COMMISSIONER LAMKIN:

Q. Good afternoon, Dr. Davidson. Thank you for your testimony.

With regard to this slide that's up right now, did you perform any analysis on other wells that were logged through the Lower San Andres to see if their saturations conformed to what you found in this well?

A. We did. When I was able to do -- the wells that penetrated into the San Andres that were available to me, some of them didn't penetrate all the way through. I was also able to -- the other thing that we did is I had wells inside the EMSU that were disposal wells and a few wells outside the boundary of the EMSU that were disposal wells that did penetrate the entire section.

And yes, we did find evidence of small intervals of residual oil up and down the system, much like is displayed in this exhibit here, one that you're looking at. However, when we made efforts to try to correlate them, can we correlate aerially, we couldn't really correlate them very well.

And when I saw that, I'm like, there's not a layer that exists over long -- that we could identify at least, a layer that exists over long intervals or a big aerial extent where they're correlatable.

That's part of the reason I came to the conclusion that I think they're migration paths. But there's probably a whole lot more wells out there that could be interpreted that we didn't have access to. But I'll tell you, of the wells we had access to, all of them had little tiny intervals here and there of oil saturations in them, and I wouldn't expect it to be anything different.

I mean, hell, this thing, oil migrated through Southeast New Mexico into the Central Basin Platform. You know, the oil that's there, a lot of it came from New Mexico and migrated up into the Central Basin Platform. It would be impossible for there not to be a little bit of oil through the San Andres.

The question is, did traps occur in the Lower San Andres that would create an ROZ? We can't see evidence of that. But we do see evidence of little elevated saturations periodically through the Lower San Andres that, thus far, I've been unable to correlate from well to well, which indicates to me, again, that they are migration paths and not ROZs.

Q. What can you tell the Commission to alleviate any concerns that this was not a well that was cherry-picked for low oil saturations in comparison to the other ones that you analyzed?

A. What you might do -- I don't remember how many of the water disposal -- the -- I think there's the -- again the data set I had early on consisted of the 746 went all the way through. There's other wells that penetrate some distance into the San Andres. They're included in my original testimony.

And then I think in the rebuttal, I included one of the outlier water disposal wells. I can't remember which one. It may have been Yaz, the well that is designated as Yaz. And you can see in those wells that yeah, there's periodic saturations that show up.

I'm not sure how many of the wells that I've -- in fact, I think we turned over all of them, didn't we? We turned over all the wells that I interpreted that penetrated the whole distance. Those PDFs are available. You're welcome to look at them and see where we actually did, and each well will calculate a little bit of oil periodically.

And I think there's four or five wells that we actually handed over that were water disposal wells, but they penetrate the entire interval. And you can see those periodic oil saturations calculated in them, so we've provided that data.

Q. Is that part of the exhibit packet that was submitted with the case?

A. I believe it is.

THE WITNESS: Mr. Rankin, is that the case? I mean, it's certainly something we could.

MR. RANKIN: My PDF is not cooperating, but I believe, Dr. Davidson, you included them in your appendix to direct testimony. So I don't --

A. They were there, and we provided -- after Ms. Shaheen determined that we use those, that they were important, we provided them to the Empire at that time. And so I don't know what the final disposition was. I know they've been provided to some of the parties here at least.

Q. With regards to the loss circulation zone above the high gamma ray marker, have you seen any other drilling reports or mud logs or anything like that outside of Goodnight's claims that would indicate that that is consistent across the formation in that area?

A. Again, this is my understanding, and so just understand this is what I understand, what I've been told. In the wells I evaluated, I had Goodnight provide the top of the loss circulation interval for every well -- when they lost circulation, I said to tell me where that top is, and those are posted, they're posted on my logs, where the loss circulation occurred.

Now, anecdotally, I've heard that the Pilot and the other injection operators experienced the same type of loss circulation when they penetrate these anhy- -- as soon as they get out of the bottom of the anhydrite intervals, that they lose circulation. Again, the Pilot and the others could provide that information.

Potentially, I have -- again, I haven't interpreted their logs. I'm told that loss circulation below this little yellow band is common with all the water disposal wells that are present. I can't confirm that. But I do have loss circulation tops for all the Empire wells -- I mean, all the

Goodnight wells.

And it's consistent that once you get down into this interval, I want to say, and I'm told that tens of thousands of barrels are lost and they drill for long periods of time with no returns, and that's -- when I found that out, that's when I said this thing's got to be karsted; you just don't get that kind of behavior.

And it's always been unusual to me that we could drill entirely through the Grayburg Upper San Andres interval and maintain circulation. It's roughly the same pressure. I think it's 1300 psi up in the -- or higher up in the Grayburg San Andres interval. It's maybe 1,500 psi down below. Right?

But we could drill through that entire interval, and as soon as we get through -- into this interval with what I call bedded anhydrites, when we drill out of the bottom of that, we consistently lose circulation. I'm going, how can that happen if it's not a karsted interval? And how could we have all this volume injected and not see a major pressure increase?

And so I did -- the conclusion that I draw, that aquifer is huge and we have isolation, you know. And Mr. Wehmeyer was trying to, you know, paint me into a corner: Well, can you say for certain?

No, I can't say for certain based on this diagram. But the preponderance of the evidence, at least that I've seen so far, makes me comfortable with saying that this interval and this interval are separated from one another.

And I think Mr. Knights has even talked about other potential barriers that exist in the Upper San Andres and the Grayburg that also help isolate these two. So it's not just me talking. There's going to be other evidence presented as well.

Q. Okay. And I think that that leads into my last question, which was, in the scope of work that you had, you didn't do any analysis into a barrier to fluid migration between the San Andres and the Grayburg, just the Lower and Upper San Andres?

A. No.

COMMISSIONER LAMKIN: Okay. Thank you.

HEARING OFFICER HARWOOD: Thank you, Mr. Lamkin.

Mr. Rozatos, last but certainly not least, questions for Dr. Davidson?

CHAIR ROZATOS: Mr. Hearing Officer, I'm sorry, I'm having technical difficulty as I was trying to unmute.

No, I do not have any questions. Thank you.

HEARING OFFICER HARWOOD: Let me ask you, Mr. Rankin. It seems, based on everything we've heard from Dr. Davidson, which seems like everything he conceivably knows on this subject, do you have any redirect examination you even need to do?

MR. RANKIN: Mr. Hearing Officer, I do -- I think I would like to do a little bit of redirect with Dr. Davidson. Although it's possible that after I have a meeting to evaluate it, I may curtail it significantly. There are a few points that Mr. Lamkin raised that I think I would like to address. And there are a few others that I would like to address as well, given that we have, you know, just about 20 minutes left before 5 o'clock, and it was a long day.

I may suggest, with the Commission's approval, that we reconvene in the morning to complete the redirect.

HEARING OFFICER HARWOOD: Chairman Rozatos, what's your preference on that?

CHAIR ROZATOS: I'm good with that. We can call it a day. It's already 4:40. So why don't we call it a day, and then we can start back up again in the morning.

HEARING OFFICER HARWOOD: All right. I mean, I assume this is a captive witness, that it's not going to inconvenience Dr. Davidson if we don't get him off the stand today?

CHAIR ROZATOS: I agree. And the doctor is tired.

Thank you, Doctor, for your time.

HEARING OFFICER HARWOOD: I think your voice needs a break anyway, Dr. Davidson.

THE WITNESS: That's fine. I'm happy to keep going on forever.

HEARING OFFICER HARWOOD: All right. So, let's break for the day and pick back up again bright and early and fresh tomorrow at 9 o'clock.

Thank you all and thank you, Madam Court.

CHAIR ROZATOS: Thank you. We'll meet everybody at 9 o'clock tomorrow.

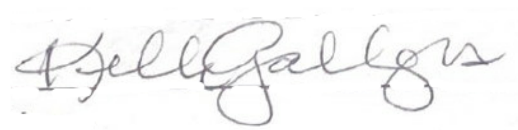
(Proceedings adjourned at 4:41 p.m.)

AFFIRMATION OF COMPLETION OF TRANSCRIPT

I, Kelli Gallegos, DO HEREBY AFFIRM that on April 21, 2025, a hearing of the New Mexico Oil Conservation Commission was taken before me via video conference.

I FURTHER AFFIRM that I did report in stenographic shorthand the proceedings as set forth herein, and the foregoing is a true and correct transcript of the proceedings to the best of my ability.

I FURTHER AFFIRM that I am neither employed by nor related to any of the parties in this matter and that I have no interest in the final disposition of this matter.



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