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

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

APPLICATION OF MESQUITE SWD, INC. FOR APPROVAL OF A SALTWATER DISPOSAL WELL, EDDY COUNTY, NEW MEXICO. CASE NO. 20472

APPLICATION OF MESQUITE SWD, INC. FOR APPROVAL OF A PRODUCED WATER DISPOSAL WELL, EDDY COUNTY, NEW MEXICO. CASE NOs. 20313, 20314

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

VOLUME 2 of 2

June 28, 2019

Santa Fe, New Mexico

BEFORE: WILLIAM V. JONES, CHIEF EXAMINER
MICHAEL McMILLAN, TECHNICAL EXAMINER
BILL BRANCARD, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, William V. Jones, Chief Examiner; Michael McMillan, Technical Examiner; and Bill Brancard, Legal Examiner, on Friday, June 28, 2019, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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ALSO PRESENT: Mr. and Mrs. Baker
Ms. Kathleen Murphy, NMOCD

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EXHIBITS OFFERED AND ADMITTED

(8:38 a.m.)

EXAMINER JONES: Let's go back on the record in the docket for June 27th. This is actually June 28th. We have three cases we continued from May 31st. I'm William V. Jones. This is Bill Brancard and Michael McMillan.

We're going to again call for appearances in the cases. These are the cases of application of Mesquite SWD, Incorporated to approve produced water disposal wells -- well in Eddy County, New Mexico. We have three cases styled the same way, Case Numbers 20472, 20313 and 20314.

Call for appearances.

MS. BENNETT: Good morning and thank you being here today.

My name is Deana Bennett, and I'm here on behalf of Mesquite SWD, Inc. And with me today is Susan Bisong also from my firm, Modrall, Sperling. And also with us today are Clay Wilson and Riley Neatherlin from Mesquite SWD, and the Bakers of the Baker Ranch are also with us here today.

Thank you.

EXAMINER JONES: Other appearances?

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe. I'm representing Kaiser-Francis Oil Company in one of the Mesquite cases -- I think it's -- I can't remember which number -- and Solaris Water Midstream, LLC in all of the cases. I have no witnesses in these matters.

EXAMINER JONES: Mr. Padilla.

MR. PADILLA: I'll let Mr. Brooks go first.

MR. BROOKS: Okay. David Brooks, Energy, Minerals and Natural Resources Department, General Counsel Section, representing the Division -- the Oil Conservation Division.

MR. PADILLA: Mr. Examiner, Ernest L. Padilla, Padilla Law Firm, Santa Fe, for Blackbuck Resources, Inc.

EXAMINER JONES: Any other appearances?

We understand Mr. Roach had appeared for a party that's in the back. We've got that on record, though.

MR. BROOKS: I believe we do. Yes.

EXAMINER JONES: I was just making sure nobody else showed up because we continued these cases.

Before we get started, I'm going to pretend that we didn't quite remember what's going on here, so instead we have a fishing hole, we asked why we're here, and so I'd ask Ms. Bennett to please summarize your case and why you brought these cases.

MS. BENNETT: Thank you. I appreciate the opportunity to summarize the status of where we are today and give everyone a refresher, since it's been just over a month, I think, since we last met on these cases.

What Mesquite is here today for and has brought these cases for is to have three applications approved, and those are in Case Numbers 20313, 20314 and 20472. Mesquite originally filed those applications administratively. They were filed as administrative applications in July and, I want to say, August or September, and the Division denied those applications administratively based on a rote application of the 1.5-mile spacing requirement or rule or policy or guideline -- I'm not sure what to call it -- and stated that Mesquite could seek a hearing examiner hearing of those -- of the applications, specifically the Laguna Salada applications.

So Mesquite then filed for a hearing examiner review of the three applications, and Mesquite is requesting that those three applications be analyzed and approved under the regulations -- or under the regime, for lack of a better word, that was in place at the time applications were submitted, which was a one-mile spacing requirement -- or understood to be a one-mile spacing requirement. After the applications were submitted, at some point the Division determined, without notice or an opportunity for comment by anyone, that there should be a 1.5-mile spacing requirement, and it was that requirement that was used to deny Mesquite's application.

So Mesquite is here today and has been here just asking for the Division to apply the spacing requirement that was in place at the time that Mesquite filed its applications. There were no other deficiencies with Mesquite's applications noted at the time, and so Mesquite is here asking for those applications to be approved under the regime that was in place at the time.

And so Mesquite really has two points in its -- that we made last month in these cases, first that the 1.5-mile spacing requirement has no basis in the rules or regulations or law and so shouldn't have been applied mechanically. And even if there was some 1.5-mile spacing requirement that could be applied, its application is not warranted here under the facts of these cases and the site-specific analysis that was done for these cases by experts in geology, geophysics, seismology, reservoir engineering studies. All of those site-specific, locations-specific analyses demonstrated that even if the 1.5-mile spacing requirement is somehow warranted, that it's not warranted for application to these three wells.

And so we made it through our case-in-chief last time. We put on -- and by we, I mean Mesquite. We put on all of our expert witnesses, and at the end of the day, we recessed to today to allow for the direct examination of Mr. Goetze by Mr. Brooks and cross-examination by myself and the other two lawyers who have entered their cases in these cases, Mr. Padilla and Mr. Bruce.

EXAMINER JONES: Thank you.

Any administrative matters we'd like to go through?

MS. BENNETT: Yes. Thank you.

At the last hearing, there were some -- there was some discussion about the form of my exhibits, of Mesquite's exhibit, specifically that the geology exhibits needed to have headers identifying the formations. And so I have updated all of the geology exhibits to show the formation in the header so they're easier to read. I also consecutively paginated the exhibits so that when referring to specific exhibits, we can refer to them by page number rather than by tab or by subtab. So those are the changes that were made to the exhibits that I have provided to everyone today --

everyone of record, I should say.

EXAMINER JONES: Any objection to the modification of the exhibits that were admitted?

MR. BROOKS: No objection, Mr. Chairman.

EXAMINER JONES: No objections?

MR. PADILLA: None.

EXAMINER JONES: Thank you for modifying them.

MS. BENNETT: And I would ask at this time that the Mesquite exhibits be admitted into the record in all three cases.

(Mesquite SWD, Inc. Exhibit Number 1 with Tabs A through F; Exhibit Number 2 with Tabs A and B; Exhibit Numbers 3 through 5 are offered into evidence.)

EXAMINER JONES: Okay. Mr. Bruce, can you summarize what your client has entered in this case?

MR. BRUCE: Well, in Case 20314, the Laguna Salada 19 SWD No. 1, I entered an appearance for Kaiser-Francis simply because of some terms on -- I think Kaiser-Francis was looking at some proposed well locations. But they've agreed -- both parties have agreed, Mesquite and Kaiser-Francis, so there is no issue. I'm just preserving their rights by entering an appearance.

We did not enter an appearance for Solaris in the three Mesquite cases, but since -- at the last hearing, it was more or less agreed that Mr. Goetze should only have to testify once, I entered an appearance for Solaris in these cases just so I could cross-examine if necessary.

EXAMINER JONES: Mr. Padilla, your client?

MR. PADILLA: Pretty much in the same boat as Mr. Bruce. We're here on Case 20463, and the Division has opposed our case. So we'll see what Mr. Goetze has to say, and then we'll cross-examine and do whatever we have to do, and then we'll put on our case.

In terms of rebuttal witness or anything, we haven't heard what he has to say, so we will probably be asking -- I will ask my -- my witnesses to comment on especially their engineer and UIC expert to comment on -- on Mr. Goetze's testimony. So we're going a little bit further than just putting on our case because of the way this hearing is being conducted so that the Division will not have to present their case three different times.

EXAMINER JONES: Okay. And your client being Blackbuck?

MR. PADILLA: Blackbuck.

EXAMINER JONES: Mr. Brooks, can you -- do you want to summarize what you're going to show us today?

MR. BROOKS: Yes. I believe, Mr. Examiner, although it's been a while, that the record will reflect that I reserved opening statement to the beginning of the Division's case.

So, Mr. Chairman and Honorable Commissioners -- I'm not sure there are any Commissioners here present. I'm sorry. It's three people up there.

But Mr. Chairman -- Mr. Examiner, Mr. Counsel, on behalf of the Division, I disagree with just about everything Ms. Bennett has said, beginning with the proposition that it's been over a month since we had -- the hearing started in this case, and I would point out that May 31st to June 28th is not over a month.

(Laughter.)

MR. BROOKS: But be that as it may, Ms. Bennett's position on the law is very different from mine except in one respect. I concur that there is no legally binding policy of 1-1/2-mile separation or any other amount of separation that would require the denial of these applications. It cannot be a legally -- a legally binding policy, binding on the Division and on the applicants because it's not in any rule that has been adopted and filed with the State Records Office as a rule, and that is required by the State Rules Act for any policy that binds persons other than internal policies that affect only Division personnel.

That does not preclude the Division from offering evidence or the Division from deciding that application should be denied because the wells in these cases are not sufficiently separated to provide the maximum -- or the effective maximum protection that can be provided against the possibility of induced seismicity from the -- from disposal into the Devonian in these wells. That is a -- that is the position that the Division takes. The Division does not need, for this purpose, to distinguish between these wells or the hypothetical wells because no other hypothetical wells are at issue in this case.

The Division will offer expert testimony from Mr. Phillip Goetze that is based on a very large, very extensive investigation of the literature on the subject of induced seismicity, and that will tend to indicate that separation of distance is an important consideration because if wells are too close together, you will get a concentrated flow from -- from the wells, which will be -- which will disrupt the pressure regime existing in nature to a greater extent than a dispersed or less concentrated or less -- or lower volume injection.

Furthermore, these wells are close to the basement, the igneous rocks that form the earth's surface below the sedimentary crust. Well, of course, they're part of the crust, too, but -- in which there is more tectonic activity, and that greater tectonic activity in the crust makes the deeper formations more susceptible to induced seismicity.

I know that Mr. Goetze will give us a very learned discussion of that subject. Now, if he is asked whether or not he believes that 1-1/2 miles is necessary for most, if not all wells, he'll probably say that it's necessary for a lot, and I will leave Mr. Goetze to say what he does or doesn't say. But that does not affect that case.

The only thing that affects this case is if the 1-1/2-mile separation is a reasonable requirement for this case and these wells, because while there is a Division policy -- nonbinding policy of an area of review of one mile -- of one-half mile around injection wells, there is no rule that says that any well that is -- that is not within one-half mile of another well automatically gets permitted. It is still necessary for the Division to decide whether the conditions shown -- there will be an influence -- there will be -- whether the conditions shown are consistent with maximum protection of the environment and public health. We believe that seismicity is part of the environment, and if it gets too bad, obviously it can affect public health because people aren't very healthy when the house falls on them. And, furthermore, we are required to protect underground sources of drinking water under federal law, and seismicity can disrupt -- can change the nature of the formations and, therefore, cause fresh water to be present where it has not been in the past or to be absent where it has been in the past.

We ask you to listen carefully to Mr. Goetze's testimony and evaluate it against those principles.

Thank you.

EXAMINER JONES: Thank you, Mr. Brooks.

We have your prehearing statement, and you list only one witness. Is that the only witness you plan on presenting?

MR. BROOKS: That is our only witness.

EXAMINER JONES: Will the witness please stand and the court reporter swear the witness?

PHILLIP R. GOETZE,

after having been first duly sworn under oath, was questioned and testified as follows:

EXAMINER JONES: You may proceed.

DIRECT EXAMINATION

BY MR. BROOKS:

Q. Mr. Goetze, good morning.

A. Good morning.

Q. Mr. Goetze, I'm going to ask you to summarize your background and qualifications, and then I'm going to ask you certain specific questions -- qualification questions and then going to offer you to the Division examiners as an expert witness.

Would you please summarize your qualifications as a geologist or, what we call them now, geoscientists and as a hydrogeologist?

A. My name is Phillip R. Goetze. I'm currently employed by the Oil Conservation Division in the Engineering Bureau. I was hired in February 2013 and have been so employed by the Division up to this present time.

As part of my obligations and requirements and responsibilities, I have been active in the UIC program, starting off with initially the review of applications and, with that, expansion into responsive to EPA, as well as the requirements to fulfill our obligations under the primacy agreement.

In addition to my work as a UIC technical reviewer, I've also been asked to assist in writing rulemaking, as well as addressing other issues involving oil and gas regulations and operations. I've also participated as a hearing examiner with over 300 cases, including cases involving saltwater disposal.

Prior to this time, I had been employed by numerous organizations, including private corporations such as Glorieta Geoscience, Tetra Tech, Guillen [phonetic], Arctic Slope, which was the original Leedshill-Herkenhoff, as well as the United States Geological Survey, the United States Bureau of Mines, Billings & Associates, Charles B. Reynolds & Associates and the Bureau of Land Management.

With regards to oil and gas, I have participated in the most significant EIS's regarding drilling and wilderness in the state of Wyoming. I have also participated as an oil and gas expert for both Bureau of Land Management and the USGS in Wyoming and Nebraska and Kansas and Colorado.

On the geohydrology side, I have also done investigations, hydrologic studies for a variety of activities ranging from well developments for such entities as the City of Rio Rancho, the Village of Taos, as well as the City of Albuquerque. I've also participated in delineation of a variety of environmental investigations, as well as remediation ranging from volatile organics through RPRA [sic; phonetic] items, as well as inorganics such as nitrate plumes. I have appeared before -- I have submitted decision documents for Interior Board of Land Appeals and have been deposed in federal court and also have appeared before Commission in questions where I represented the Division.

Along with that, I've been doing it for 40 years.

Q. Does your experience include extensive involvement with consideration of the issues of induced seismicity?

A. It is a process we have been learning over the last five years.

Q. Have you written some papers on the subject?

A. No. I have not written any papers.

Q. But you have a summary of this, do you not, that's included in your exhibits?

A. At the direction of the Division Director, we have made an attempt to compile the best information available, as well as consult those that are more knowledgeable in the Division in an effort to build a base of information.

Q. And were you primarily involved that effort?

A. Yes, I was.

MR. BROOKS: Mr. Examiner, I submit Mr. Goetze as an expert hydrologist -- I'm sorry -- geologist and hydrogeologist.

EXAMINER JONES: Any objection to that?

MS. BENNETT: I don't have any objections to Mr. Goetze being identified as an expert in geology and hydrogeology, but by his own admission, he is not an expert in induced seismicity or seismology and has not prepared any studies of his own relating to seismology. And so I would object to him being admitted as a seismologist or having -- or even -- other than summarizing other people's work, presenting any of his own opinions about induced seismology because by his own admission, he is not qualified for that.

MR. BROOKS: I would dispute that he has said anything that would not qualify him as a seismologist other than the last question -- most seismologists would not recognize a geologist as a qualified expert in seismology, but we believe that -- we would submit that like any expert witness, he is entitled to rely on those materials that are reasonably relied on by a person -- customarily and reasonably relied on by a person in their profession and -- though we would be tendering exhibits on that assumption.

MS. BENNETT: I have no issue with the tendering of exhibits based on that assumption, but what I do object to is any opining on the meaning of those exhibits for purposes of this hearing. And I would also note that Mr. Goetze, although -- while he does have a storied CV, he does not have any studies that he's identified related to the specific locations at issue here, and so that further goes to my objection about him opining on the seismicity or induced seismicity on these specific locations.

MR. BROOKS: I believe, Mr. Examiner, if Ms. Bennett has objections to particular portions of the testimony, she should raise those at the time they're offered.

EXAMINER JONES: Mr. Bruce?

MR. BRUCE: No objection to Mr. Goetze being qualified as an expert witness in the capacity that Mr. Brooks summarized.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I have no objection, but I also second Ms. Bennett's objection on the basis of his qualification on induced seismology.

EXAMINER JONES: Mr. Brooks, can you repeat exactly what you -- what you're offering the witness for?

MR. BROOKS: Geology and -- geology and geohydrology.

EXAMINER JONES: Petroleum geology?

MR. BROOKS: I did not limit it to petroleum geology.

EXAMINER JONES: Okay. It's a GSA type of deal? Covers everything?

MR. BROOKS: Well, yes. Many people think a lawyer is a lawyer, which would allow me to testify on the issue of tax law, and I understand that would be unfair. But then on the other hand, Mr. Goetze's testimony, I believe, reflects that he has rather diversified experience in fields of geology.

EXAMINER JONES: Is Mr. Goetze a certified petroleum geologist?

MR. BROOKS: I don't know. You may ask him.

VOIR DIRE EXAMINATION

BY EXAMINER JONES:

Q. Mr. Goetze, are you a certified petroleum geologist?

A. No. I am a certified professional geologist in the states of Texas, Alaska and Arizona. I'm a certified environmental manager in the state of Nevada. I am a chemical and hazardous materials specialist. I'm a member of AAPG for some 30 years. Let's see. I'm a member of the ASTM International. I sit on two committees. Let's see. And I'm also a professional geologist -- certified professional geologist under the American Institute of Professional Geologists.

Q. Just for the record, New Mexico doesn't have a certification?

A. New Mexico does not have any type of certification for geologists.

Q. But they don't have a limit on practicing as a geologist in New Mexico based on certification in other states?

A. There is no -- no, they don't.

Q. That was poorly worded on my part.

EXAMINER JONES: Okay. He is so qualified.

MR. BROOKS: Thank you.

CONTINUED DIRECT EXAMINATION

BY MR. BROOKS:

Q. Now, Mr. Goetze, you have before you a volume of exhibits, which we will intend to offer, of which you have compiled, right?

A. That is correct.

Q. And most of these exhibits relate to induced seismicity in some way; do they not?

A. That's correct.

Q. And are all of the exhibits that you will be discussing materials that a geologist would reasonably rely upon to form opinions?

A. That is correct.

Q. Okay. Would you -- well, the sum of your exhibits are actually just descriptive in this case and that is true, is it not, of Exhibit Number 1?

A. That's correct.

Q. Would you tell us what Exhibit Number 1 shows?

A. Number 1 is a summary of the information that we put together in regards to giving general guidance of where -- the cases and the relative relationship to the information available. This is mostly a summary of what we put into the prehearing statement, along with a summary of each well and its well location.

Beginning with Figure 1, Figure 1 presents a summary of Cases 20313 and 20314, which are the Laguna Salada wells, the 13 and 19 wells. The 13 well and the 19 well are plotted with the yellow on the map and is shown with respect to a population of blue circles, these being approved wells with either orders existing that are still active, as well as -- or wells that are being drilled. The significance here is showing that we received the two applications, the Laguna Salada 13 and the Laguna Salada 19, plotted them, along with another application that came in at the time, which was the Laguna Salada 7. Review and placement of these wells placed the Laguna Salada -- the two Laguna Salada in close proximity to each other, roughly a little more than a mile.

With respect to existing -- existing orders and operations, the Laguna Salada 13 was within a mile -- 1.08 miles of the Intrepid SWD, which is not active as an order which is still in standing and at this time has been acquired by a new operator. Along with that, to the south, the Laguna Salada No. 19, plotted to be roughly 1.06 miles, away from the Lakeside 20702 SWD No. 1, which is Mesquite's well as far as ownership of the order.

Other wells in the area but lying outside what we normally would use as a three-quarter-mile projection includes the Striker SWD No. 1, which is a commercial well, and the Layla 27, which is a smaller radius because of the fact that this well was a well which was permitted much earlier. Its well design is such that it is limited in its ability to take larger tubing.

With this projection, we made the recommendation to the director that the Laguna Salada SWD No. 1 and the Laguna Salada 19 SWD No. 1 be denied administratively because of the proximity. And that would be a proximity not only with existing wells but between each other.

The third application by Mesquite, which is Figure 2, was for the Baker SWD No. 1, being Case 20472. In this case the placement of the Baker with respect to the DS 6 SWD No. 1 Y created an overlap with a distance of 1.24 miles as opposed to what we were looking for, 1.5-mile separation.

And also plotted on here was a second application made by Mesquite for the Red Bellied Cooter SWD No. 1, which came in after the Baker, which also would have overlapped the Baker if the Baker had been approved.

Other than that, the Red Hills SWD No. 2, by Mewbourne, is significantly far enough away that it raised no concerns.

The final figure shows the relationship of the Solaris Water Midstream application, which was the Predator 17 Federal SWD No. 1, Case Number 20465, as well as the Blackbuck Resources Olive Branch Federal SWD No. 1, which is Case Number 20463. This area as depicted shows a little more congested area, especially with regards to the volume of applications coming in at this period of time. The Division felt that the .55-mile separation between the Predator Federal 17 and the proposed Olive Branch Federal SWD No. 1 was not going to be a good choice for administrative approval. With that, projection against existing wells, which include the Mesquite SWD Station SWD No. 1, which is active, and the Mesaverde SWD No. 3, which is active, it really -- the significance of the 1.3 miles was such that these two wells, the Division felt, was not going to be a direct issue, but it was going to be a problem if both of these were approved at the locations proposed.

The McCloy SWD No. 2, though it is showing a small radius, it is probably going to have a request for a change in its operation which may offer the ability to increase its injection volumes from its current 15- to 24,000-barrels of water per day. But again, its separation is such that it should not be a concern.

Also within this figure, you will see that we had Case Number 20462, which was Blackbuck's JJ Federal SWD No. 1 in Section 18, which they have since dismissed and removed from the docket. And we still have a pending OWL SWD Operating application in for the Cotton Draw SWD No. 1, which is in Section 19.

And just as a side note, looking at the location, there are at least two other pending cases or protested applications and one which was removed from or withdrawn from administrative application by the applicant. So this area as opposed to the other area shows an intense placement of applications for wells.

So the Division's concern in the case of the Solaris and Blackbuck well is that potential for one or the other is viable, but the two together represent a concern and, therefore, were administratively denied and the opportunity for hearing offered.

Q. Mr. Goetze, to summarize, then, each of these wells that you've discussed that is involved -- the permitting of which is the subject of one of these cases before us today, is either too close, in your opinion -- well, I won't ask your opinion right now. I'll wait until after you summarize -- is less than 1-1/2 miles

from another existing well or less than 1-1/2 miles from another proposed well?

A. That is correct.

Q. Now, are all of these -- all of these wells to inject into the Devonian Formation?

A. All these wells have been proposed for the same injection interval and have requested injection rates in excess of 30- to 40,000 barrels of water per day.

Q. In the overall scope of injection applications that we get, is that a high-volume injection?

A. This is a category for which the Division does feel that we have gone beyond typically what we've seen in the past, which has always been below 20,000 barrels per day, and so we have now these larger volumes with larger capacities. Yes.

Q. Now, is the Devonian Formation in this area productive of oil and gas?

A. We have information that it has a low probability.

Q. Okay. I believe that Exhibit -- I want to be sure I have right what the situation is on these exhibits, but I believe all the exhibits -- Exhibit 1 is the only background exhibit, and the remaining exhibits deal with induced-seismicity issues; is that correct?

A. That's correct.

Q. Okay. Would you go on then to Exhibit 2? What is Exhibit 2?

A. Exhibit 2 is the final product of what was the National Underground Injection Control Technical Workshop conducted by EPA. It is entitled "Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches."

Q. Okay. And that was authored by the technical -- technical work group put together by the United States Environmental Protection Agency?

A. This is correct.

Q. Now, Mr. Goetze, would you summarize for us what is significant in Exhibit A -- in Exhibit 1? And I'm going to allow you to go through and comment on specific matters in there that you feel are sufficiently significant to bring to our attention.

A. Exhibit 2 is, shall we say, a snapshot of the first portion of the guidance document provided to the Division. At the beginning of 2015, we received notification of the issuance of this final document. With that, it was provided to us by Dallas, by Region VI, and we were informed that we should review this document and move forward with what was deemed appropriate.

Q. Before you go ahead, let me ask one thing at this point. Is this the type of reference that as a geologist you would consider reasonable and customary for geologists to rely on, the materials in this document, as a reference?

A. Yes, it is.

Q. Proceed.

A. With the document in hand, it was reviewed. For this opportunity, there are several areas which provide information that was utilized by the Division. The first point would be on page 3 where it cites "Regulatory Authorities," and it is highlighted to provide the basis of what we've been doing. It's an "Evaluation of induced seismicity is not new to the UIC program. Some UIC well classes address seismicity with specific regulatory requirements. The Class II UIC program does not have regulations specific to seismicity but rather includes discretionary authority that allows additional conditions to be added to the UIC permit on a case-by-case basis. Examples of the discretionary authority include additional requirements for construction, corrective action, operation, monitoring or reporting; (including well closure) as necessary to protect underground sources of drinking water. In the included case studies, the UIC Directors used discretionary authority to manage and minimize seismic events.

"Potential underground sources of drinking water risks from seismic events could include loss of disposal well mechanical integrity, impact to various types of existing wells, changes in underground storage [sic] of drinking water water level or turbidity, USDW contamination from a direct communication with the fault inducing seismicity, or contamination from earthquake-damaged surface sources. However, EPA is unaware of any underground source of drinking water contamination resulting from seismic events related to injection-induced seismicity."

Using that as a basis of moving forward with some sort of program, we would go into page 9 which provides the "Geoscience Factors Related to Injection-Induced Seismicity." With that, two items stood out with us --

MR. BROOKS: But to be sure we're all on the same page, let me interrupt. The page numbers that you are referring to begin on the -- well, if you start on Exhibit 2, behind Tab 2, there is a memorandum of two pages, and then there is a titled page, one page, and then there are italics-numbered pages 1 and 2, which constitute the index, and then there are pages numbered

ES-1, 2 and 3. And then you start with page 2 -- no, page 1 beyond that.

Is everybody on the same page?

MS. BENNETT: Yes.

EXAMINER McMILLAN: It says "Geoscience Factors," is where we are, on the overhead.

Q. (BY MR. BROOKS) Okay. It starts on page 8; does it not? Are we on page 8, Mr. Goetze?

A. We're moving on to page 9.

Q. Okay. So we're on page 9. Then continue.

A. So from this summary of "Geoscience Factors," two items were highlighted by review of the literature. One is communication with the basement rock. And as we'll go on, in the case of Dagger Draw, we will see that this becomes a very important factor, and with other literature, it has become one of the more prominent concerns as to injection and separating any type of injection fluids from the basement rock.

The highlight here would be -- is the vertical distance between an injection formation and basement rock, as well as the nature of the confining strata below the injection zone and key components of any specimen of injection-induced seismicity. It also highlights that faulting and basement rock can extend into overlying sedimentary strata, which has been apparent.

With that comes the importance of porosity and permeability and injection strata. We have taken a small -- essentially, the Devonian and Silurian and have identified this as a good target area. Therefore, the information obtained on the injection interval becomes critical in seeing if these wells are going to be successful, as well as what future events will occur with injection, especially the injection of cumulative number of wells in the same location.

Along with that, suggestions come with regards to what was observed in the EPA's effort, which included obtaining more information such as bottom-hole injection pressure gradients, running Hall plots, maintaining an inventory of information, which typically we do have, which is pressure and volume injection.

From here, I would move within this document to page 25, and here the outcome or at least the highlights of what the EPA came up with were "Lessons Learned," to wit: The items we would less [sic] like to highlight is the "Acquisition of additional data may provide an improved analysis. Additional site characterization may be beneficial." This is becoming more and more evident as applications were coming in, again pointing to the demonstration of the confining layer between the disposal zone and basement "and structural interpretation does not indicate faults extending into basement rock."

Turning to the next page, page 26, in "Lessons Learned," it also highlights the fact that "Existing systemic monitoring stations are generally insufficient to pinpoint active fault locations; more sensitive and better located monitoring systems are needed to accurately identify active faults and detect smaller events."

Keeping that in mind, we will go to the last selection, which is page 34, which highlights some operational approaches. The EPA had proposed three types of tools for dealing with induced seismicity, which include operational monitoring and management. At this period of time, when -- and we're looking at between 2015 and 2017. We thought operational approach would be the best method, but we did not have enough information to go that route to do some of the operational abilities that had experienced success in other locations such as Texas and Oklahoma. "Modify injection well permit operational parameters as needed to minimize or manage seismicity issues" was not an option for us, but we did look at the concept of "separate multiple injection wells" -- "separate multiple injection wells by a larger distance for pressure distribution since pressure buildup effects in the subsurface are additive."

So with that in mind, we in the Division also would reference -- I will not reference any more of this article -- or this paper.

So with this EPA document in hand, the Division was directed by the director at that time to come forth with some sort of pathway to deal with applications, which had increased in size as far as requests for injection volume, as well as develop a plan to look down the road. At that time the rate of applications was significantly less than what we have currently.

Q. Okay. Summarizing, what lessons do you feel should be taken? What is your takeaway from this paper, from Exhibit 1?

A. At this time the Division, based upon what it had as its information and what would be provided in exhibits later on, was to look at the EPA recommendations and start with something fairly relatively simple with the information we had available.

Q. Does the EPA recommend greater scrutiny of applications closer to the basement -- to inject into formations' basement rocks?

A. It is their recommendation.

Q. And did you -- I believe you noted this. Did they mention that faults are not always easy to find and there should be great scrutiny to determine where relevant faults may be?

A. One of the issues was not only the seismic arrays and the information cataloged, limited in many cases, but subsurface information tends to be one of the critical elements that require additional enlightenment, as we say. The information available on Precambrian faults, as well as subsurface formations where there is no activity such as an oil and gas, tends to be limited.

Q. Yeah. Now, is that true of the area in which these particular wells that are involved in this case are being proposed?

A. The information basinwide is quite limited for the Devonian.

Q. There are few wells -- are there few or many wells that penetrate the Devonian in the vicinity of these wells?

A. There have been wildcats and there have been deeper wells into the Precambrian for exploratory purposes, but compared to the 55,000 wells, their numbers are quite limited.

Q. And if you were working as a petroleum

geologist and you were asked to advise as to where the best well locations would be, would you characterize the well control, as it is called by -- in our professions, as adequate or less than adequate?

A. I would deem it less than adequate.

Q. Go on then, please, to Exhibit Number 3 if that is all you have to comment on at this time on Exhibit 2.

A. That's correct.

Q. Okay. Now, Exhibit 3 is actually a collection of exhibits, correct?

A. Correct.

Q. What is it? What are they?

A. Exhibit 3 -- as part of the effort by the Division, Exhibit 3 provides a series of sources that were consumed and used as an effort to come up with some sort of audit with regards to the EPA request to provide some sort of induced-seismicity program.

Q. Well, now, these are papers on the subject?

A. That's correct.

Q. And are these peer-reviewed papers?

A. Yes, they are.

Q. Are they materials of the kind that a professional geologist would reasonably rely upon to make conclusions?

A. That is correct.

Q. Continue then and tell us what's -- describe what they are and tell us what's important about them.

A. The EPA paper cited the USGS Bulletin as an effort at the request of the EPA to look at induced seismicity. And this paper was done back in 1990, and the research was done back in the 1980s. Its conclusion here is to basically highlight -- on page 4, there is a table that provides a summary of what the USGS found is the probable sources and induced seismicity events that they were able to find in their review of open documents.

Q. Once again, this numbered page 4 of Exhibit 3 -- after you go through the Roman-numeral-numbered pages, you get into the Arabic-numbered pages, and we're talking about Arabic-numbered page 4, right?

A. That's correct.

Q. Continue.

A. With that in mind, at this period of time in 1990, the primary observations made by those qualified in the field show that we were looking at secondary recovery as a probable source of induced seismicity. There is only a handful of wells associated with injection for waste, and many of those are what are referred to as Class I wells.

Keeping that in mind -- and the discussion is found in the appendix on page 42, a marked increase in earthquakes above magnitude 3 was observed to correlate with the dramatic increases in the number of injections wells operating with pressures greater than 70 bars. What we're seeing here is that the original effort to find induced-seismicity events has been mostly focused on secondary. We are not seeing the level of injection or proposed injection which would come followed by expansion of the Permian and other areas resulting in a significant increase of volume.

The other item at this time also is that induced seismicity is becoming a raised issue because of the presentation of the DOE WIPP site and with it the concerns that it, in the Permian Basin, would have issues or needs to establish some sort of baseline for which the evaluation of what had historically just been secondary recovery and now with the current situation would start to include injection for disposal. So this document really relates to the fact that early interpretations are limited and the investigation in it is very specific.

The second exhibit, 3-B, starts to open up the world of seismicity as being more prevalent and more widespread. This is the USGS effort in 2015, which now takes us into currently where the shift is entirely moved towards the observations, especially in Texas and Oklahoma. Of significance in this article is page 622, where it is stated "If disposal of wastewater by injection is the principal cause of the excessive seismicity, as now appears almost certain, it nonetheless needs to be stated clearly that disposal of wastewater by injection, UIC Class II wells more often than not results in no detectable seismic response. Consequently, the existence of a well has low predictive power for seismicity itself."

This made us think what would be the best approach to find out what would we need to move forward with some sort of program -- again going back to the EPA's observations and lessons learned -- and develop something that would satisfy the needs of the Division, as well our obligations.

One other thing it did highlight is the "dozens of earthquakes in the Barnett Shale of north Texas that clustered near several high-volume injection wells, but none associated with other injection wells. This suggests that for increased fluid pressure to induce earthquakes, three conditions must be met: (1) a preexisting fault must be present; (2) the fault must be oriented suitably in the tectonic stress field to slip; and (3) the pore-pressure perturbation must be sufficient to overcome the frictional strength of the fault."

So in 2015, again, we're seeing this effort to look at the Precambrian, as well as injection, but still we don't have specifics for the Permian that we can look at and provide some sort of document to move forward with.

I would look to page 625 of this article, which, again, the conclusions, "Earthquake activity has undergone a manifold increase in the U.S. midcontinent since 2009, principally in Oklahoma, but also in Arkansas, Colorado, Kansas, New Mexico and Texas. The nature of the space-time distribution of the induced seismicity, as well as numerous published case studies, strongly indicates that the increase is of anthropogenic origins, principally driven by injection of wastewater coproduced with oil and gas in tight formation." So even with the report in 2015 and EPA guidance, they're still coming through with trying to put together a project with responding to the EPA request.

I will move on to the next exhibit, which is number 3-C. This is included -- we were referred to this by at least one source of the legislature. This is the "Congressional Research Service" paper from 2016. In this we would highlight page 22, which again says, "Among other findings, the report identifies three key components that must be present for injection-induced seismic activity to occur." Essentially, the congressional folks have looked at the EPA paper and carry forth this understanding that "sufficient pressure buildup from disposal activities...a fault concern...pathway allowing the increased pressure to communicate from the disposal well to the fault" are a prime outline and effort for any program to deal with induced seismicity should look at.

And then I would go to page 23. Here what this paper does do is compile the state initiatives that includes also the fact that we've had other organizations such as Ground Water Protection Council and Induced Seismicity Work Group and the Oil and Gas Compact Commission -- or the Interstate Oil and Gas Compact Commission have all been working together to practically discuss the possible association between recent seismic events occurring in multiple states and injection well.

And we also received, in light of this, that we participated in the IOGCC efforts to come up with a modeling package, which was sponsored by Ground Water Protection Council. Discussion of that would be limited to the fact that the focus at that time -- and this was of recent, 20- -- 2018 -- 2017 through 2018 -- that the effort was to put together a product that could be used for managing after induced-seismicity events had occurred. So in many ways, it was designed primarily for Texas and Oklahoma, whose frequency of induced-seismicity events have been so high that they needed a tool after an event occurred to manage their resources. Unfortunately, this was not a feasible opportunity for New Mexico.

Finally, I'll move on to Division Exhibit 3-D, and this, of course, comes from the folks at Stanford. The facility there is one of the premium facilities in the United States in regards to evaluating and looking at and putting together what is currently being used as a method of induced seismicity fault slip modeling. The Division does recognize it, and it is utilized with applications to the Division, and the Division has requested it in many cases.

Of this article, what is coming out -- this one is -- I believe it is 2015, that the effort by Stanford Research Institute is starting to develop a process of what many people refer to as the stoplight process, that we look at a certain amount of risk assessment as opposed to having seismic events and then trying to compensate for those events. Stanford tried to put together and categorize what we should be looking at in a decision-making document as to what to go down the road with not only after you've had an event but before you've had an event when you have something in application.

And, again, we would go to pages 6 and 7. Here we start to see the matrix that is being developed by many states with regards to what items should be looked at when considering the final question as to whether a permit should be issued or not issued. Up till now, what concerns as far as exposure, and the grid is high, moderate and low, and breaking up into categories, what types of features, what should be of concern. Stanford recommended the critical facilities, structures and infrastructures, environment and populations.

The Division looked at these, and population was something that we felt was not very much of a consideration. Critical factors or critical facilities in our realm would probably be related not only to current oil and gas operations but also surface facilities, as well as infrastructure, structures and infrastructures. We can also include that we do have things such as acid gas wells and caverns and brine wells that also share the same environment. And we would also note that we do have the WIPP, and we have the mines involved in this same area of the basin.

Q. Most people are familiar with acronyms, but the WIPP is what?

A. The Waste Isolation Pilot Plant, which is operated by the Department of Energy as a facility to receive waste from the United States Nuclear Program for its weapons systems.

Q. And how far is this -- how far is the area of --

A. With regards to -- well, this is right in the middle of the basin, along with the activity for the oil and gas production which is going on now.

Q. Similar geologic conditions?

A. It is related to it.

Q. Okay. Continue.

A. We would then ask you to go to page 13 for which we would highlight one paragraph. "Of particular concern, and a key observation in mitigating risk, is whether there is the potential for triggered earthquakes to occur on relatively large, critically stressed, pre-existing basement faults. Over the life of an injection project, it is thought that pore pressure perturbations have the potential to migrate toward critically stressed, permeable faults in the crystalline basement. A relatively simple conceptual model involving the migration of pressure perturbations" -- sorry -- "from injection horizons in Oklahoma to active basement faults has begun to evolve that shows how long-duration fluid injection has the potential to trigger slip on relatively large faults."

So with that in mind, again we're being pushed into the world of looking at the separation, the placement, the injection, the volume and deciding what would be the best way as post -- as mitigation prior through the application process and then ultimately as part of an overall program.

And I think that's Exhibit 3.

Q. Okay. Then I believe the next several exhibits are specific to the states of Oklahoma and Texas and their experience with induced seismicity.

A. That's correct.

Q. Okay. This presentation is becoming quite lengthy. Would you be able to give a general summary of the paper -- of the next three papers in an accelerated form?

A. The lawyer is asking me to speed it up. Okay (laughter).

And, again, the Division offers this up as a basis of how we came to our decision.

Exhibit 4 is a summary of the effort by Oklahoma, and it is again one of these efforts from past presentations at hearing that if you don't include it, you can't discuss it. So we offer to you the experiences of Oklahoma, which went through a significant effort to try to address it, especially after both the governor and the population -- the public population became very adamant that there be something done.

So in August of 2015, I mean, you have a 60-day period. You had a 38 percent reduction in injection among several operators. You have entire areas, areas of reviews, which they do a ten-kilometer or 122-square-mile review of injection wells and seeing what their relationship to the faults in the basement are.

In here we would find also the program being developed by Oklahoma, which includes an increased area of interest, which is different from their area of review. This area of interest is used for their triggered seismicity. We also know that by 2017, the Oil and Gas Conservation Division of Oklahoma was able to change, in rulemaking, the ability to have an administrative ability to shut in wells and change their operations deemed -- based on an outcome of a study,

which we would note that this Division does not have that authority.
It also went into a more proactive stance, and it developed its red light, yellow light, green light system where it would actually take a seismic event and then it would address that through a study and, therefore, adjust the wells or cluster of wells as deemed necessary.
The last article in Section 4 summarizes the fact that the short-term traffic light -- and now they have a long-term earthquake management system -- has been successful in reducing the induced-seismicity issues. But it took them almost four years to come together with a product that both industry and the regulatory body were to put into place.
Again, the concern here is that the Division does not have this type of induced seismicity at this time, but nor does it have a lot of the information that was available to Oklahoma, especially with the ability to put out and obtain larger earthquake catalogs, as well as intense surveys, which we do not have.
Q. And that is a question, I believe, that you and I have discussed. Could you tell these people what is the adequacy of earthquake reporting data in the

Delaware Basin of New Mexico or the Delaware Basin for purposes of demonstrating where less-than -- that the larger-magnitude earthquakes have occurred?

A. The ability for information to be obtained on seismic events has been primarily a function of the New Mexico Bureau of Geology and Mineral Resources. As a result, they're directed to maintain a seismic array in relationship to the WIPP, as well as their functions to oversee activities in the Socorro area. The presence of seismic sensors has only increased since 2017 with the expansion of adjacent state operations such as TexNet for Texas, as well as with Colorado adding more sensory devices in the Raton Basin under the USGS.

Q. Now, to give the examiners some perspective of these things, what -- what is the magnitude of an earthquake on the Richter scale of an earthquake that would be sensed by people living on the surface in the area but would not be -- but would be the minimum, in the range of lowest that would be?

A. Reportable, from 2 to 3. 2, you don't really feel it. 3, you may, depending upon what your situation is. Most of the concern has been raised for -- for events that are greater than 3, essentially.

Q. Just generally summarizing, how -- how common are earthquakes less than 3 -- seismic events less than

magnitude 3 compared to seismic events greater than magnitude 3?

A. In the world of life, the ones below are very, very frequent. The ones above are not. So --

Q. Okay. So if you have data on an area that gives you only the number of -- or the frequency or areas where there are reported earthquakes and there is not an extensive sounding system to detect lesser earthquakes, do you have an adequate basis for predicting how much seismicity there is in the area as you would evaluate it from a geologist's point of view?

A. On the basis of obtaining information, it's always better to have more information.

Q. I agree.

A. But along with that comes the task of sorting through it and seeing what is relevant. Just because you have more information doesn't necessarily give you a better focus. And this is the lesson learned in Oklahoma. The ability to put in more arrays and have more information many times was misinterpreted as an increase in seismicity and it really wasn't.

Q. Now, I interrupted your discourse. You may continue.

A. I'm done with this discourse of Number 4.

Q. And which exhibits does that take us through?

A. That is 4-A through 4-E.

Q. Okay. Now, what is the situation with Exhibit Number 5?

A. 5 brings more home the point of the effort which is now occurring on the Texas portion of the Permian Basin, as well as their overall state program, and this would be Exhibits 5-A through 5-E. The primary lesson learned from here is that Texas embraced the ability to start up their own program, which included several authorities which provide technical response, as well as technical guidance, to address induced seismicity, of which one of these is known TexNet, which is their array system, as well as reporting system for seismic information. Along with that, they have several groups of which -- one is the CISR, which is the -- their seismic cooperative effort between industry and several state agencies, including the Bureau of Economic Geology.

What we would point out here is that Texas has, being a larger area with different basins of production, had to deal with several issues, not only the Permian Basin but also the Dallas-Fort Worth area and lower down towards south of Pecos in the Trans-Pecos region. The effort by Texas to establish it was well-funded, well-established, and with it came multilayers of effort, not only the seismic array, legislation, as well as development of the research for addressing specific issues identified from either seismic events or at the recommendation of the technical review staff either at the Bureau of Economic Geology or with the CISR's group.

It would include also a change in the process for obtaining a permit from the Texas Railroad Commission, which included an expansion of the requirements for the applications, which included an assessment for induced seismicity. And with that, the Railroad Commission would put together a baseline package.

We at the Division have been talking to the Railroad Commission, and we would offer up as Division Exhibit Number 11 the effort which has been given to us by CISR, which is where we're going to probably head down. But at this point, Texas offers us the biggest ability to put in a program that has been thoroughly investigated, as well as developed, in a basin that is shared between the two states.

Within Exhibit 5 of particular note is 5-B, and the reason this was included is primarily the discussion of the Ellenburger as far as an injection zone. In this case it's in the Dallas-Fort Worth area.

We historically have had injection in Ellenburger. That'll be discussed later. But this was chosen, in some locations, as a preferred injection zone. The summary of the paper highlights the fact that the Ellenburger is not necessarily a very good receptor in light -- receptor for injection of water in light of its lithology and its location in the stratigraphy, which offers an ideal conduit for a contact with the Precambrian basement in many parts of West Texas, as well as in southeast New Mexico.

There was concern raised as to how many New Mexico wells were placed into the Ellenburger, and at this time, we're happy to say that of those, there are only ten, and they are all minimal injection. But the Texas experience, which was also dealing with Ellenburger and which the EPA cited in its early audit of the Texas program, became an easy target by the Division to say that we should isolate ourselves from it as a result of what happened around Dallas-Fort Worth.

Q. Let me ask you one other thing about the Ellenburger. I believe -- do you recall the testimony that was given at the prior hearing of this case -- or the prior proceedings in this hearing, I should characterize it, wherein the witnesses -- or the Applicant suggested that there is a -- a barrier between

the -- in this area -- in this particular geologic area between the injection zone and the Devonian and the Ellenburger which would prevent communication of injection from the Devonian into the Ellenburger?

EXAMINER JONES: Mr. Brooks, can you hold that thought?

MR. BROOKS: I can.

EXAMINER JONES: And we can take a ten-minute break.

THE WITNESS: Ah, come on.

MR. BROOKS: I'm for that.

EXAMINER JONES: Do you intend to put on the entire testimony without cross-examination?

MR. BROOKS: I don't think I would be able to put it on without cross-examination, but I'll get through it before lunch.

EXAMINER JONES: I meant did you want to put on part of it and then cross-examine and the rest of it and then cross-examine or --

MR. BROOKS: No. My intention was to put on all of it, unless the attorneys request otherwise and you rule that they're right. That's your decision.

EXAMINER JONES: It sounds like a plan.

Let's take a ten-minute break.

(Recess, 10:11 a.m. to 10:25 a.m.)

MR. BROOKS: We have an additional exhibit that's not in the binder, and I think we'll pass out copies to other people now so it won't be as disruptive.

EXAMINER JONES: I don't have a preference for lunchtime, so you guys --

MS. BENNETT: Like noon, I guess, or whatever seems like a natural break.

MR. BROOKS: Well, you know, we discussed yesterday about a 45-minute break with coffee in the morning, but --

MS. BENNETT: Well, I would prefer a shorter lunch break if at all possible so we can finish.

And also I'd just like, for point of clarification, to make sure I will be given the opportunity and other lawyers will be given the opportunity to object to the exhibits before they're admitted into record.

MR. BROOKS: Exhibits will be tendered at the conclusion of the testimony in the way that is customary in the OCD. It took me a while to learn that when I first came here because it's different than it's done in court.

EXAMINER JONES: We are recording this so please proceed, Mr. Brooks.

Q. (BY MR. BROOKS) Okay. Very good. I thought I

had asked -- I was asking about the Ellenburger?
Correct.

A. You were at the Ellenburger, and we were talking about above it.

Q. And this paper deals with disposal into the Ellenburger, right?

A. Correct.

Q. And that is not proposed in any of these applications?

A. No, it is not.

Q. Now, do you recall the testimony that was offered previously to the effect that there is a permeability barrier in this geological area between the Devonian where the water will be injected and the Ellenburger?

A. Yes. The Applicant has identified the portion of the stratigraphic column known as the Ordovician as being the lower confining layer to isolate the injection interval from the Precambrian.

Q. In your opinion as a geologist, is the evidence -- not just the evidence that has been admitted in this court but the evidence that is available, the limited well control that we have, is it adequate to assess that the -- to reach a conclusion as to whether or not the Ordovician barrier will be sufficient or

sufficiently prevalent in the area to prevent communication to the Ellenburger?

A. The overall quality of information offered through subsurface information such as cores and/or a seismic is quite limited and, with it, an understanding of the lithologic characteristics are at best a general description.

Q. Is it true that there's been no evidence presented so far regarding examination of cores?

A. That's correct.

Q. Are there numerous sources from which cores could be obtained that would shed light on this subject?

A. There are facilities with cores, but our view of our own state's core library shows a very limited number.

Q. I'm sorry. What shows a very limited number?

A. The number of cores representative of the Ordovician.

Q. Okay. And have any of the Applicants presented any seismic evidence -- any 3D seismic evidence?

A. No. The Applicants have provided nothing other than what is known as publicly available information.

Q. Are there a lot of areas that have been explored by proprietary relating to seismic?

A. There are vendors who do offer a higher quality

information. These have been used in applications
submitted by a variety of operators, including Matador,
Chevron, 3Bear, which have been used to -- as well as
Midstream, which provide a much clearer picture as to
what the potential faults are at that depth.

**Q. Conceding that -- as Ms. Bennett noted in
her -- in her objections at the time you were qualified
as an expert, that you probably would not be -- I would
not ask you to interpret any specific 3D seismic. But
assuming -- with that understood, is it well understood
among geoscientists that 3D seismic is the gold standard
for characterizing lithological properties in various
formations?**

A. 3D seismic offers a much higher tool of
interpretation, as well as a much higher tool of
duplication.

Q. Thank you.

**Now, tell us about the Ellenburger in
Texas.**

A. Well, with regards to the information presented
in the paper, which is included here, as well as the
assessment by the Bureau of Economic Geology, as well as
the occurrences of Ellenburger on the platform -- the
Central Platform in New Mexico, the Ellenburger tends to
represent a reworked karst and post-karst environment

and has cut-and-fill structures -- K structures that have been filled with debris and then resolidified.

With this, it has a -- on the Central Platform, a target of production, and it, with the expansion of injection, became a favorable target prior to the ability to understand its relationship and the effects it may have on preexisting faults and potential for induced seismicity.

MS. BENNETT: I'd like to just object to the testimony about the Ellenburger because it's irrelevant. Mesquite, as far as I know -- well, Mesquite is not requesting to inject into the Ellenburger, and I don't believe the other two Applicants here today are requesting to inject into the Ellenburger.

MR. BROOKS: Respectfully, I think that was clarified in the testimony before we even asked about the Ellenburger.

MS. BENNETT: That's why I object to this line of questioning. It's irrelevant to the issues before the Division about whether injection into non-Ellenburger is appropriate.

MR. BROOKS: My response to what I understand the objection to be is that in view of the witness' testimony, that we do not have adequate or ideal information for assessing the adequacy of the lithological barrier between the Devonian and the Ellenburger in this area, that we need to consider what might happen if there is drainage into the Ellenburger; therefore, the testimony is considered as relevant in this proceeding.

EXAMINER JONES: Still object?

MS. BENNETT: Yes.

EXAMINER JONES: Okay. Go ahead with your --

MR. BROOKS: I'm through with my line of questioning. I was just going to invite Mr. Goetze to go ahead and tell us what else he thought was relevant about Exhibit 5.

THE WITNESS: I believe that is all I have for Exhibit 5.

Q. (BY MR. BROOKS) Okay. Let's talk then about Exhibit Number 6.

A. Exhibit 6 is a collection of documents. It is primarily from the New Mexico sources. The first three items are from the Bureau of Geology and Mineral Resources. And the first paper is a circular done by Dr. Allen Sanford. The presence here, again, brings forth the concern in the basin -- the Permian Basin as to the WIPP and its active monitoring of the situation regarding seismicity. During that evaluation at that time, for the opening of the WIPP, again it reflects the USGS effort that only occurrences with enhanced recovery have been the main concern as far as what potentially could be induced seismicity. Since this program is still going on and has been considered to be expanded, we have more participation by the Department of Energy and with it this movement away from purely just looking at secondary recovery to new sources of induced seismicity. We provide this as a basis for one of the issues having other responsibilities in the basin for which the Division's actions will be directly related.

Provided in B and C are the current catalogs. B and C demonstrate again a limited focus of catalog primarily centered around the basin due to the WIPP action, but with it comes the discovery of probably the most famous documented case in the basin of induced seismicity, and that would be South Dagger Draw.

Q. And is Exhibit 6-E an assessment of that by an eminent authority?

A. Well, 6-D the assessment by the authority. 6-E is a supplemental summary of the wells that were identified, as well as additional wells the Division feels may have contributed.

Q. Now, was much of the Dagger Draw injection --

in all fairness, was much of the Dagger Draw injection into the Ellenburger?

A. It was both into the Ellenburger and into lower portions. And in each case, the wells that were identified, originally the concept of induced seismicity was not a concern and --

Q. That was typical at the time; was it not?

A. That's correct.

So both the process of evaluating disposal at deeper formations was primarily limited to underground sources of drinking water, as well as confirmation in certain wells. The testimony provided through the C-103 -- or the affirmation provided through the C-103 sundry notices stated that the wells had been plugged back. In some cases, the documentation to support that did not exist. And so with that, the potential for conduits existing, even no filing had claimed otherwise, did still exist.

I would note that in both of the catalogs that the recommendations and the identification of the swarms of activity associated with the Dagger Draw by Dr. Sanford, as well as Dr. Bilek, is still associated with the disposal. And then the paper provided was the University of Colorado, a summary of the existing catalog information and the correlation with that data that this source of activity in the Dagger Draw is directly related to the injection of disposal water.

Q. Okay. Now, let me interrupt you here because my question is premised on the fact that much of this injection was into the Ellenburger itself. Is there not -- do these papers contain any data -- is there anything in these papers that suggests that the effects were not limited to those effects produced by injection directly into the Ellenburger?

A. There are no other suggestions given.

Q. Other than injection directly into the Ellenburger?

A. Into Ellenburger and deeper, yes.

Q. Deeper. Okay. Thank you.

But the primary cause was found to be injection into the Ellenburger?

A. That is the observation.

Q. Which according to these authorities is not probably a suitable formation for injection?

A. That is correct.

Q. Okay. Now, I'm going to go ahead and let you go ahead with your narrative.

A. Well, the inclusion of the summary table points out one of the predicaments as being a regulatory agency -- and that would be Division Exhibit 6-E -- is that many times we would have wells drilled to a certain horizon and then we would go forth, if a well was drilled deep, to be able to plug back and use a shallower formation for disposal. With the increased likelihood of the situation of not having proper separation from the injection interval and the Devonian and Silurian and the Ellenburger, which can provide a conduit, makes the Division susceptible to the best information offered through the operator. This makes this separation and knowing where the well is located and where it is in the stratigraphic section even more important than would be typically reviewed for a, say, shallower well.

Q. Okay. Now, we talked about the lack of adequate well control to assess the -- the sufficiency of the -- of the alleged permeability barrier between the Devonian and the Ellenburger. Do you have any other opinions as to the adequacy of that barrier based on information about the barrier rather than about the lack of adequate characterization?

A. Other than the fact that we're basing a lot of the information on a lithologic description which is very limited so that the ability of its permeability and porosity, though generally described, may vary locally and with it the potential for having issues with its ability to provide proper separation. I would also add to this that we also have new information coming in as the wells are being drilled and with it the Division has not had the time or the opportunity to correlate subsurface information for which there is concern as to where the bottoms of many of these wells are being placed as total depth.

Q. And what is the thickness of this barrier compared to the thickness of the Devonian Formation in the areas where it's -- where it can be reasonably --

A. Again, regional mapping has shown that it thins towards the shelf and then deepens towards the center of the basin, the axis.

Q. Well, proceed with your thoughts.

A. Well, then the last item -- the last article with Rubinstein, which is 6-F, they raise the concern, based upon the model up in the Raton Basin as to whether the isolation, as was identified when these wells were approved for disposal, has been sufficient enough to isolate their -- assume that the separation of the injection interval -- at least the agencies offering the applications had assumed injection separation from Precambrian by what was perceived as being a thick sequence, but there is discussion as to whether the reasonable mapping of the area provided enough competence in that events up there may be related to a fact that there was not as much permeability and porosity barrier as originally thought and the existence of faults which may provide migration downward.

Q. Okay. Let's then talk about -- are you through with the takeaway from Exhibit 6?

A. Yes, at this time.

Q. Let's go ahead and talk about Exhibit 7. And before you go into it, Exhibit 7 is New Mexico-specific, correct?

A. This is correct.

Q. Continue.

A. In an effort to move down towards a program to have something to provide an overall change in the disposal program, as well as address the EPA's request for moving on to a method of screening for induced seismicity, this is kind of a summary of why we ended up in Devonian-Silurian.

The Division, at the time of the transition with horizontal wells, went through a mass of applications which characterized a much shallower zone as the Delaware Mountain Group as being a preferred disposal, and historically disposal in the Delaware Mountain Group had been a preferred interval as a result of both it being shallower and it being nonproductive.

However, beginning with the advent of horizontal drilling from 2010, as the abilities to go in and take nonproductive intervals and make them productive, we found that the Delaware Mountain Group was not an ideal situation. We also came to realize that in our method of approval that we historically looked at disposal wells as singular items. We have a very demonstrative case regarding the effects of four wells together injecting into the Delaware Mountain Group resulting in an impact of horizontal wells.

With that in mind, the Division revisited its primacy agreement, and within the primacy agreement, our demonstration, which was written back in 1980, the Division had identified the Devonian strata. It had, in essence, quantified it under our primacy agreement per the EPA -- and this is the first exhibit, Exhibit A -- as an alternative to the San Andres, which was then the preferred, and then after that, the Delaware Mountain Group, which became the second best, but then with horizontal drilling became an obvious problem.

7-B is the effort by NMOGA, New Mexico Oil and Gas Association, to assist the Division in putting together a justification for moving towards the Devonian, again knowing that the number of wells requested is going to be increased and with it the probability of similar impacts to correlative rights to occur. Again, they found not only that we were having issues with correlative rights in particular [sic] locations, but the fact that we were looking at potentially impacting Avalon Shale and top of Bone Spring was increasing exponentially and that we had in certain areas water flows in the Delaware Mountain Group, which interfered with both the ability to use it as a disposal interval, as well as we were seeing fracturing of the formation and the confining layers that have been approved in the SWD orders.

The third insert in this section was a presentation given by myself for the Produced Water Conference. This pretty much summarizes my previous statements and made available to the public our move towards depth in Devonian wells as an effort to move and take the injection to a deeper zone that we thought would be both beneficial and that we would not have to drill through it and would have the potential volume for taking what would become larger volumes of water.

The identification of the Devonian was also selected based upon its low probability of being used as a target for horizontal drilling with most of the injection -- I mean most of the production being in the Upper Permian or Permian section.

This also included a reference to the fact that we were trying to space wells out and try and utilize a method to take into account both the current efforts done by -- in this case we actually included Lund, Snee and Zoback paper, as well as what was happening in the Devonian-Silurian disposal effort by the Division. Matter of fact, the one plate that does describe it shows the density along the Malaga-Loving Fairway, as we call it, which has shown a high density of saltwater disposal wells. And with that, we had several cases brought for hearing in an effort to get some sort of information from operators as to what would be the best way to approach the concentration of wells in such an area and develop some type of idea as to how we would approach it.

And the last item in here is the Lund, Snee and Zoback paper, which was referenced in my presentation. It does have several concepts. We do reference it. Many of the modeling that has been done with the Stanford research model uses this information compiled from public sources for identifying fault slip potential and for use in identifying faults that are run through the models.

I would ask that -- on page 132, the authors do highlight the fact -- the results shown in the figures, which are commonly used and commonly referenced.

Q. Let me interrupt you to be sure everybody is on the same page.

A. Okay. Numbered 132 at the bottom.

MR. BROOKS: The numbers in Exhibit 7-D are -- are unique to Exhibit 7-D. They don't go throughout Exhibit 7. And the A, B, C, D of Exhibit 7 are separated by yellow dividers in the notebook that we have.

Now, did we provide notebooks to opposing counsel?

MS. MURPHY: Yes.

MR. BROOKS: Okay. Good. So they would be separated in the binders.

Q. (BY MR. BROOKS) This is page 137 in Exhibit 7 -- 7-D.

A. 132.

Q. 136.

A. I'll raise you (laughter).

Q. Continue.

A. So just to the one paragraph, the author states, "The results shown in Figures 3 through 5" -- and I'll enter those, the fault potential maps and the regional mapping, as well the local mapping -- "are not intended to provide a definitive view of the fault slip potential across this complex basin, nor do they constitute a seismic hazard map. While the stress field is complicated in this area, the changes in the stress field are coherent and mappable. We consider the greatest uncertainties in the map to be the lack of knowledge of subsurface faults and the magnitude and extent of potential pore-pressure changes in areas where increased wastewater injection may occur in the future, especially wastewater injection that might change pore pressure on basement faults. Operators wishing to use the FSP tool" -- fault slip potential tool -- "to screen sites for fluid injection should use detailed fault maps that are specific to the injection interval, the underlying basement, and any intervening units, which take into account geometric uncertainties."

Q. Okay. Have you said everything you think is significant about Exhibit 7?

A. I believe so.

Q. Okay. Let's turn our attention to Exhibit 8. Exhibit 8 is very different from the others in that it is a collection of OCD documents in terms of orders. Can you explain why all these orders were included in this exhibit?

A. They became what the Division saw as a means of finding some sort of tool to utilize and methodology as to how to address induced seismicity. In each case, an operator brought forth information that was used to compile what they thought was the induced seismicity potential and the risk associated with the operation of their wells, and probably, in some cases, the NGL presentations do take into account adjacent wells.

What we tend to show in here is this migration over time with the information coming in, as well as the Division's focus from being concerned primarily with what we thought was an original issue being that we don't have something in place to screen to start looking at assessing fault slip but also to look at a whole program to address this product and how it impacts how wells are screened, as well as what happens afterwards.

The Snee-Lund-Zoback effort shows us that we may approve something, but this has to be a process that grows and goes with the inclusion of new wells, as well as the operation of current wells. This, the Division does not have at this time.

But to go through the first case, Mesquite was requesting an increase in tubing size. This was denied and with it a list of concerns which were included in the order. And I will disclose that I wrote the order. With that, Mesquite did go to hearing and presented before Commission the application, along with the information to address the information or the deficiencies that had been found in the order by the hearing examiner.

At this time, this period of operation -- prior to this time, the upsizing of tubing had not really been even considered a concern. Most wells were below 15,000 barrels of water per day and, with it, the issue of proximity and the ability of the interaction of the wells not fully realized, as well as not fully documented. With Mesquite's effort and the Commission's approval, we now entered into a realm where we were looking at much larger volumes of injection and, with it, we were going down a similar road of development that was observed by both in Texas and Oklahoma with regards to how saltwater disposal wells were changing in that we were heading towards much larger volumes and greater numbers.

We did note that the Commission -- in its final conclusions and order, the Commission ordered -- and this would be ordering paragraph three, "The Commission directs the Division to continue conducting a work group on UIC Class II wells in order to develop best management practice and advise the Commission concerning the need to develop new regulations related to disposal wells."

In an effort to satisfy that requirement and seeing how we were getting larger volume wells and much greater numbers, we recommended to certain parties, operators such as Black River Water Management and Chevron, that we would like to go to hearing in an effort to get at least a basis of seeing what type of impact, what type of activity, what type of reservoir information, what type of subsurface information was available. And so the cumulation of information in here with the cases represents several wells that were brought to the Division, and they range from NGL all the way to operators, as well as companies held at the discretion of operators such as Black River Water Management. They came forth with their information, along with the request by Division to work on a series of data strings for us to approve or at least review the well.

We have -- at this point the Division is looking at a one-mile notice and a one-mile area of review, and what we are seeing in application is the fact that we're having testimony by expert witnesses as to the migration of fluid exceeding beyond the half-mile AOR, which is currently what we have under our primacy agreement. And with that information, the concern of correlative rights was raised if fluids were reaching out beyond the one-half mile radius. The fact that we are approving a permit which may impact oil and gas rights would be a direct violation of the Oil and Gas Act.

Q. Okay. Is that -- is that everything you need to say?

A. Oh, no, no. We just started.

Q. Okay. Please continue.

A. So what we get from testimony -- and in certain cases, the applicants would bring in proprietary information, and we would have a discussion and review, in many cases some 3D seismic, how far injection fluids would reach. With this in mind, we got a variety of testimony and a variety of evaluations. And so considering the life of the well, which may vary from 20 to 40 years depending upon the applicant, we started to see a pattern which at first showed a one-mile radius as being satisfactory for looking for penetrating wells, as well as the notice requirements based upon the old definition of affected persons or affected parties.

This being the foundation for the Division to go forward to the director with a recommendation as to how to screen, in most cases we were seeing a maximum injection fluid migration over 30 years that was greater than half a mile but less than a mile. The series of cases continued to follow that approach. And with the earlier cases, the recommendation to the Division Director was to utilize a three-quarter mile. It had originally been suggested to be a one-mile type of review, and then looking at the proximity of the wells, utilize some sort of template in hopes of going down the road and developing the program as the EPA requested.

And we included the testimony of Mr. Scott Wilson, from the Mesquite cases, just to show that at this point in time we have a variety of information coming at us from all directions. And when asked by counsel if there is any incentive to operators to want to locate their wells further than half a mile apart or a mile apart, the answer, "From a technical standpoint, if someone was injecting at a location, I would try to site the next injector as far away from the location as possible because this would give me a longer period of time before I ever recognize that other injection was happening. So from a purely technical standpoint, people would distribute their injectors evenly and widely dispersed."

And that is found in Exhibit 8-B. I have no further comments on these.

Q. Okay. You're talking about only 8?

A. 8. Exhibit 8.

Q. Very good. Thank you.

Then let's talk about Exhibit Number 9. I believe you've already commented on the definition of the waste that is 9-A; is that correct?

A. Well, we touched upon it on WIPP, but yes, under our Oil and Gas Act. We would reference F, in that "drilling or producing operations for oil and gas within any area containing commercial deposits of potash where such operations would have the effect unduly to reduce the total quantity of such commercial deposits of potash which may reasonably be recovered in commercial quantities or where such operations would interfere unduly with the orderly commercial development of such potash deposits."

So, again, taking back as to if there is an issue of induced seismicity, not only is WIPP a matter of concern, the Oil and Gas Act directly makes us responsible for addressing oil and gas activities that may impact the operation, as well as the ability for the potash to be mined.

Q. Do you have an opinion as to the importance of induced seismicity with regard to its potential for disrupting potash development?

A. It is -- having worked underground there, yes. And so an induced seismic event 1,000 feet underground is always an exciting thing. So it is, at this point, still an obligation of the Division to consider this as part of the program in dealing with how we are going to go in the future with the saltwater disposal.

Q. Very well. Go ahead.

A. The second item, 9-B is 2016. In our effort to go ahead with some sort of effect, a program that could address the -- the concerns not only of the Division to operators but at the queries of the legislature. So at this point, the only thing we have in our toolbox, you might say, is the fact that we're trying to stay away from Ellenburger and Precambrian basement. The concept of going forward with some type of modeling and/or rulemaking is limited, and we are still collecting data. So at 2016, we are still compiling, as well as looking at the simplest and most basic of trying to reduce any potential for induced seismicity.

Division Exhibit 9-C is a summary of my notes related to an effort in 2018, over two months, to address what was becoming a growing concern that with the exponential growth and applications all wanting to inject into the Devonian that the Secretary, along with the Division Director, organized a work group for looking at the UIC rules and regs and seeing what path forward would be best.

With this is a selection of participants and at least four meetings where the discussion was offered up to folks with greater expertise than me and, with it, developed some sort of path forward as to how to properly manage or at least what rulemaking we should go into. At that time we had made a recommendation in the Division, based upon the fact we were filling in voids, that the three-quarter-mile distance would be a preferable method of screening on the go while trying to bring forth a program that would represent a good screening process, plus a post-injection opportunity for reconsideration of permits still in effect.

With that, there were also discussions with other parts of the UIC rule, which are not relevant here, but they did include injection into shallower Delaware Mountain Group, as well as enhanced recovery and our Class I's, as well as Class II acid-gas wells.

Based upon that and due to the short term of the administration at that point, the consideration was not to go into rulemaking at that time with the intent of rewriting everything, but we did make an effort to initiate a realignment of the UIC program under our New Mexico Administrative Code to have definitions that correlated to the language of the Code of Federal Regulations, 144 -- 40 CFR 144, 145, 146, 147. So the other initiative -- and this also was the fact that the definition of "affected person" would change as a result of the horizontal rule.

With this in mind, the first effort done following the technical work group was to realign the definitions in our New Mexico Administrative Code, as well as pursue forward with a criteria of increasing the information requirements that had been done in Texas and looking at a rule change that would provide a program for induced seismicity as an element of it.

Division Exhibit 9-B are the recommendations that were provided to us by the New Mexico -- input from the technical group, as well as the New Mexico Oil and Gas Association, as well as from the Engineering Bureau with regards to issues that we see and the concept of what should go into the -- be specifically included in the rule that is still under consideration.

Q. Let me stop you right there and interrupt. Are you familiar with the way in which -- well, are you familiar with Section -- I believe it's 12B. Unfortunately, I don't have my statute book here, but the statute that -- the portion of the statute that

defines the specific powers of the Division and the Commission?

A. Yes.

Q. And do you recall that it states that the Commission and the Division may make rules or orders with respect to the new rate and subject matter? It's not limited to a rulemaking authorization, in other words. Is that a correct characterization of the statute?

A. I believe it is a correct characterization.

Q. Okay. So that would indicate that if in a particular case the Commission -- the Commission or the Division determines that there is not a rule covering that case but that the matter is relevant and should be examined in order to determine that case, would it be appropriate for the Commission to take that into consideration -- to take that matter into consideration in formulating its order in that case?

A. That is correct.

Q. Okay. So if the Commission has concluded in the past -- or the Division has concluded in the past that induced seismicity is something that should be considered in evaluating injection applications, even though there is no rule on the subject at this time, those considerations become relevant --

A. I would agree.

Q. -- in formulating the order?

Okay. Thank you.

A. And to that end, Exhibit 9-E, as far as the exhibit there, with the approval of the director, we started to include a statement for those folks who had submitted additional information based upon this one-mile area of review and also the one-mile notice and the statement of induced seismic events, the probability of. However, at this time we are still looking at the proximity of the wells based upon information coming in. The three-quarter mile was still prevalent at the time of these applications as being a tool for management.

And then for the last exhibit, 9-F, it's a paper by Dr. Scanlon from the Bureau of Economic Geology. It is the last page, page 108 -- or next-to-the-last page. It provides a summary of what we're seeing, the management of saltwater disposal wells in various programs, state agencies granting permits for SWDs or enhanced recovery wells. A number of reports have been developed with the guidance of UIC regulators for managing and minimizing injection-induced seismicity. And it refers back to the Oklahoma experience by saying, "The directives issued by the OCC in early 2016 are consistent with findings from this analysis in terms of injection rates, regional cumulative injection volumes and proximity to basement. Although permits are generally granted for individual SWD wells, the importance of net fluid budgets at local to regional scales suggests that the regulators should consider individual well permits within a larger context of the net fluid balance, as is done in Oklahoma."

Now, it does identify, "No new SWD permits are being granted in Oklahoma for wells in the Arbuckle...adjacent to the basement. In addition, permits for shallow (Delaware Mountain Group) or deep (Ellenburger Group) disposal in New Mexico are restricted to individual operators, rather than for commercial operators [sic], to reduce potential seismicity."

So we are seeing a recognition now of a process coming to us as to replace what we have been using as a template in our evaluation of applications.

And with that, I would offer up Exhibit -- Division Exhibit 11.

Q. Okay. Well, what about -- do you have -- Exhibit 10, just tell us -- what is Exhibit 10?

A. It is my resume.

Q. Okay. Now, at one point, do you recall what a Commissioner said from the bench, that he had your

resume memorized? I think that was a somewhat facetious comment, but still would it be fair to say that the people sitting here on this case, the examiners sitting on this case, probably are very familiar with your resume?

A. That is affirmative.

Q. And you have already summarized it at the time of your qualifications?

A. I have.

Q. Okay. So then go on to -- then go on to Exhibit 11, which is not in the notebook.

A. That's correct. Exhibit 11 is a package -- in our discussions with the TexNet group, both the research side, as well as the industry side, the effort to look at what Texas has done -- and we have been communicating over the last five months in looking into what Texas has done and what we would like to do. The concern gets to be how do we go through this process as a regulatory agency.

And with that, the Texas Railroad Commission has come forward with a document which they identify for internal use only, for its technical people, its staff members. Besides it being a summary of fees, as well as what they do with regards to their own rules and process, which includes the

100-square-mile seismicity screening and then the earthquake events of greater than 2 or greater than that 9.08-kilometer area of review is to be considered, it also offers up a level of technical review, which includes the addition that if seismicity screen is positive, supplemental information is required to assess the state of disposal zone and adjacent strata. So at this point, we are already seeing structure maps, isopachs, cross sections, fault hazard analysis.

We also at this point get a decision document and a scoring system, and in this the Texas Railroad Commission has applied three factors which includes in their seismic review, which is the faulting and seismicity factor, operational factors and reservoir factors. Notably in the seismicity and faulting data confidence, we have a scaling of high, medium and low and a criteria to follow in evaluating that data. Along with that, we also get a greater input as to who also is injecting into the same area, as well as a process to make recommendations to the management as to whether an application should be approved, denied or sent to hearing.

At this time we are in discussions with the State of Texas as to their methodology, as well as permit conditions, and we have ongoing discussions with the Railroad Commission as to an ability to have an exchange of information and a possible inclusion of this methodology as a means to deal with being a more scientific process -- I'm sure I'll be saying -- and the Division being able to make its recommendations to the director and satisfying the EPA request for the induced seismicity as being part of our program.

Q. Okay. Does that complete your description of Exhibit 11?

A. For now, yes.

Q. Well, for now.

A. I'm done.

Q. Okay. Thank you.

Let me ask you a few general questions then. Do you have an opinion based on -- well, let's first cover -- certain exhibits have to be excluded from this question, and I'm not entirely sure which ones I should exclude.

But Exhibit 8, for instance, is offered basically as precedent for how the Commission -- or the Division have approached this issue in hearing orders rather than for the truth of the matter stated, correct?

A. That is correct.

Q. Okay. Now, Exhibit -- certain exhibits in here are things that you authored?

A. That's correct.

Q. And you said you haven't authored any papers, so I'm trying to avoid describing them as papers.

A. Presentations.

Q. Okay. So I would exclude from the next question Exhibit 8 and your own papers because I don't want your modesty to interfere with the answer. Other than those, do all of the exhibits being offered, Exhibits 1 through 11, provide evidence of a kind that is reasonably relied on by geologists in their professional evaluations?

A. Yes, it is.

Q. Okay. Based on that evidence, do you have an opinion as to whether or not a one-half -- a separation of at least one-half mile would be appropriate indeed for saltwater disposal cases in the Devonian in Eddy County, New Mexico in these cases?

A. The Division still -- I would still stand by my recommendations.

Q. Which is?

A. That at this time they not move forward for issuance, they be denied.

Q. Thank you.

And as to your own contributions to this, were they prepared from either business records or

government records or material that a geologist would rely on in the evaluations done in his professional capacity?

A. Yes, I would.

Q. Now, if these applications were denied -- would denial of these applications promote the -- or advance the regulation of disposal of wastes in a manner that protects public health and the environment? You're looking at me quizzically. Let me restate the question.

A. Yeah.

Q. Would denial of these applications as they presently stand protect public health and the environment in the disposition of oil field wastes?

A. At this time it would be my recommendation for that.

Q. Thank you.

MR. BROOKS: I submit Exhibits 1 through 11.

EXAMINER JONES: Objection?

MS. BENNETT: Yes. I have objections to many of the exhibits, actually, but for the sake of efficiency, I will lodge a general objection to any exhibit that is irrelevant, namely those exhibits relating to injection into the Devonian -- I'm sorry -- the Ellenburger, any exhibits that relate primarily to

Oklahoma or exclusively to Oklahoma, Texas, Colorado. I could go through and identify specifically which exhibits those are for the record, but all of those exhibits are irrelevant to the issue at hand today.

More specifically, though, I would object to the admission of Exhibit Number 7-C, which is Mr. Goetze's exhibit of the "Current Status of the New Mexico Underground Injection Control Class II Program." Actually, I'll withdraw my objection to that exhibit and ask clarifying questions to that exhibit.

EXAMINER JONES: Okay.

MS. BENNETT: But turning to Tab 9, 9-C, "Summary of Oil Conservation Division UIC Technical Work Group on Part 26 Injection...and Saltwater Disposal Activities," we have no idea, other than Mr. Goetze's name and date on that memo, when this was created, the background information that was put into this. I think this lacks sufficient evidentiary foundation to be admitted into the record at this time. So I specifically object to Exhibit 9-C.

EXAMINER JONES: Okay.

MS. BENNETT: I'll let the -- I have other objections. Should I go through them serially, or would you like to rule on each one as I go?

EXAMINER JONES: Mr. Brancard?

EXAMINER BRANCARD: Go through.

MS. BENNETT: Okay. 9-D is the NMOCD permit guidelines from, apparently, NMOGA. This has no foundation. This doesn't say it's prepared by NMOGA. It has no date of preparation. We have no idea who prepared this, what inputs went into it. We don't even know the date that it was prepared. There is no author. This lacks a sufficient evidentiary foundation to be included and to be admitted as an exhibit in this matter.

And I'll ask some questions going to the weight of other exhibits as we go through them. But those two are my two primary specific objections as to the lack of foundation and validity for this proceeding, and I stand on my objection as to relevance for most of the other exhibits.

EXAMINER JONES: Mr. Bruce?

MR. BRUCE: Let Mr. Padilla go first.

(Laughter.)

MS. BENNETT: Oh, pardon me. I'm sorry. I have two more objections.

EXAMINER JONES: Yes.

MS. BENNETT: I would also object to Exhibit Number 9-F, the Scanlon, B. Weingarten and K. Murray report, dated January/February 2019. That report was generated after the denials in this case and cannot be relied on as evidence to support the denial.

For the same reason, I object to Exhibit Number 11. Exhibit Number 11 was prepared after the denials in this case were submitted, and evidence obviously submitted after the denials cannot be used to support the denial. That would be an ad hoc justification.

In addition to that, we agreed at the last hearing that no further affirmative exhibits would be submitted, and so -- and this was clearly within -- this was prepared -- I don't have it in front of me, but it looks like April 19th. This material could have been but was not included in the packet when we originally had this hearing on May 31st.

EXAMINER JONES: The material in Exhibit 11?

MS. BENNETT: In Exhibit 11.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I'm going to echo the objections made Ms. Bennett.

But in particular, without correlation to the location of the Blackbuck well, the Oklahoma and Texas exhibits ought to be eliminated. I find it interesting that there's no -- or at least should not be admitted. That the Raton Basin, which is 400 miles away from the area, about -- between 3- and 400 miles, is included as part of this presentation, and so is the Dagger Draw. The Dagger Draw, admittedly, is closer to the location of these wells, but there's no geological relation other than the generalizations of the need for rulemaking for saltwater disposal.

There is no evidence here of -- specific evidence other than the Exhibits 1 and 2 which have the circles. That's all -- that's all there is as far as any correlation, any geologic connection to the proposal. This is an excellent case for rulemaking but not to attack the applications themselves, which, if you're going to follow factors of the EPA, should be take into consideration specifically as to these applications. So I'm not going to object to those EPA factors, but they're applicable here, and Mr. Goetze should have addressed those factors as they relate to these applications. But still, we don't have a rule. Anytime that you have -- and it talks about rulemaking.

Gathering evidence from Texas or Oklahoma for adoption, it doesn't matter whether you have a work group. The most is interesting thing is the order of the Commission directing the Division to adopt regulations. To me anything else that he said is really irrelevant to the specific applications here.

So on a general basis, all this evidence should be excluded. Obviously, it will probably be taken for the weight of the evidence, but there is no connection at all with the number of exhibits that were presented here on a global basis.

EXAMINER JONES: Thank you.

Mr. Bruce?

MR. BRUCE: I would just echo what Mr. Padilla stated.

EXAMINER BRANCARD: Mr. Brooks?

EXAMINER JONES: Respond, please.

MR. BROOKS: Do you want me to respond? Yes.

First of all, so far as the objection as to certain exhibits, that they were prepared after the administrative orders in this case that previously were issued as to certain of the proposed -- of the applications -- and I believe there is a distinction between those that -- some of these applications were simply put to hearing, and others were -- there was an order issued denying them. This is not an appellate proceeding or a review proceeding de novo or otherwise.

If you look at what goes on with administrative orders -- administrative applications --

however it is characterized, and that's an issue that is before the courts now, as to how these proceedings are characterized -- the fact of the matter is that if the Division decides to conduct a hearing on the subject matter of an administrative application, in response to the application itself and not in response to a subsequently filed application by the same or another party, the Division is simply -- the hearing is simply a part of the review proceeding for that application and, therefore, any evidence that's relevant to the determination of the application should be open for consideration by the Division unless there are other valid objections to it.

Secondly, I protest as to the objections that are based on Oklahoma -- based on the fact that Oklahoma and Texas and the Raton Basin are specifically relevant to these cases, that I would concede that their relevance may be limited because the geology may be different, but it seems that their relevance is tied in, as Mr. Padilla pointed out, by Exhibit 2, which suggests that the EPA has considered these factors to be relevant to assessing the probability of induced seismicity. And if, as the Oil and Gas Act seems to direct, the Division can consider these matters in orders in formulating orders, as well as rules, these general considerations -- if induced seismicity is part of the environment and the OCD has a right and duty to protect the environment, they can consider what is relevant to determining whether or not induced seismicity is probable in orders, as well as in rulemaking proceedings. I mean, the relevance of these should not be limited to rulemaking proceedings.

And with that said and conceding that relevance is much less direct than much of the other evidence, I think the out-of-state and out-of-area considerations that are noted by the EPA should be admitted and -- that are noted as having importance by the EPA, evidence on those subjects should be admitted for their weight. Regardless of the remote relevance, they do have some relevance. Relevance, after all, is defined in the rules of evidence as -- fundamentally as anything that has a probability of rendering a conclusion in the case more or less likely, and I think the evidence of Oklahoma and Texas and other areas does indicate that it is more likely than it would otherwise be without considering that evidence, that there is a danger of induced seismicity in these cases.

I don't remember, unfortunately, if there is specific evidence related to -- related to -- if counsel has made specific objections to relevance on other grounds, but I would think that all objections to relevance in general terms to exhibits or groups of the exhibits should be overruled on the grounds that it is the responsibility of the objecting counsel to point out specifically what the objection is.

Thank you.

MS. BENNETT: And if the Division would like, I'm happy to go through exhibit by exhibit and point out which ones I object to on the basis of relevance. I don't think that's a very expedient way to proceed, but I'm happy to do that if that would satisfy Mr. Brooks.

MR. BROOKS: Well, I would point out that any -- I would -- I would -- counsel is entitled to do that if they want to. I would just suggest that maybe that's unnecessary given that this proceeding will be reviewed, if at all, de novo, and if any -- there is a legal reason that has not been considered why a particular exhibit should be admitted or not, that consideration will not be -- will not affect the -- the outcome of the case if it goes to the Commission regardless of whether the Commission includes that evidence or not.

And there is one other thing I forgot to say. And I apologize for expressing myself at such length.

On Exhibit 11, there was a specific objection -- and I believe it's in a different category -- referring to agreement of counsel. And if that agreement occurred and if it's on record, I would stand corrected if it would make that exhibit inadmissible.

EXAMINER JONES: Say that again.

MS. BENNETT: It wasn't an agreement of counsel. I stated that on the record at the end of the hearing, when we decided to conclude and move to another date, that it was my understanding that as of that point, the affirmative exhibits were as presented to us. Now, of course, if Mr. Goetze had rebuttal evidence, that would be different. But it was my understanding that as of the close of the day that day, any affirmative evidence that we were putting on had to have been finalized.

MR. BROOKS: I would recommend that the examiner examine what the record actually shows occurred before ruling on that because I have no recollection and cannot comment on that.

MS. BENNETT: I'll withdraw my objection for the limited purposes of allowing this to proceed more efficiently.

MR. BROOKS: Okay.

EXAMINER JONES: Withdraw which objection?

MS. BENNETT: 11.

EXAMINER JONES: 11?

MR. BROOKS: I'm done.

EXAMINER JONES: Okay.

EXAMINER BRANCARD: I thought that was your best objection.

MS. BENNETT: It was a good one.

EXAMINER BRANCARD: First of all, let's start from that issue, which is that what we have before the examiner is a request for a hearing on an application on the parties. I think we determined that at the last hearing. So we're not reviewing an appeal of the denial of the administrative action. This is a new application before the director, which you'll make a recommendation to the director. Recommendation of staff apparently is to deny these applications, and the director will decide that. So that's sort of what's going on here.

On the issue of the Oklahoma and Texas information, I mean, clearly, Mr. Goetze's testimony is an attempt to elucidate how the Division has derived its policy about how to regulate injection wells during a period of time when clearly injection wells are considered to be the cause of induced seismicity in other locations. And so I see that as background information that sort of gives a sense of how the Division has derived its policy.

I agree with Mr. Padilla, though, that the real issue here is what are -- what is the evidence for the particular applications? And then as Mr. Padilla said, likely the issue here is what's the weight of those documents for these applications? That's an entirely different issue for you-all to understand. Okay? So I, frankly, don't see a problem, unless you consider them immaterial, the exhibits related to Oklahoma, Texas and other areas of induced seismicity or the Ellenburger, which is obviously one of the issues that comes out in this article, is proximity to basement and is one of the issues here.

I mean, I have some concern -- my other concerns are 9-C and 9-D. Okay? I don't know that counsel has really developed sort of a foundation for this. I think Mr. Goetze testified that 9-C was sort of his notes about a task force -- a work group that has gone on last year, but I don't know who received copies of this, how it was distributed; is this more than just the personal notes of Mr. Goetze. And, likewise, 9-D, I don't know that we really had -- I can't recall. It says "guidelines," but are these guidelines internal guidelines? Are these guidelines that are submitted to the operators, the value of these documents directly related to who has seen these, who has reacted to these, et cetera? So I don't know that we really have a development of those issues here.

And so if you consider them okay, you need to consider what their value is, too, at the same time and what's the merit of these documents. Are these guidelines that everybody in the industry knows about, or are these just guidelines that the Division uses and Mr. Goetze uses in his own view of applications? I don't know. I wasn't clear from the testimony as to what that was. If you want, you can ask Mr. Goetze.

MR. BROOKS: I was going to suggest the same thing. I believe that we did not make a very good predicate for the admissibility of these documents, and rather than me trying again, I think I will get the examiners try. I admit that there are -- I did not respond to these particular objections because I didn't have a response, but that does not mean I concede that the objections are valid, merely that they're much more valid than some of others.

EXAMINER JONES: I would like to ask about 9-F. That was -- the objection on that was --

MS. BENNETT: I'm sorry. Which one?

EXAMINER BRANCARD: 9-F.

MR. BROOKS: That was --

MS. BENNETT: Yes. That is -- I objected to that because it was submitted after the administrative applications were denied. I would also note -- or was prepared after the administrative applications were denied, but I understand from Mr. Brancard's discussion that may not be a relevant consideration, although I would point out that Mr. Goetze has not provided -- I understand we're at hearing today on our new applications. Mr. Goetze has still not provided any concrete, site-specific, technical evidence showing why these specific applications should be denied. He refers to the 1.5-mile throughout his testimony as a screening tool.

So while, in my view, we are here on a hearing today, it cannot be as easily segregated from the administrative denial as one might hope because they're both inextricably intertwined at this point and both failed for the same reason. So I just do not see how this information prepared January-February 2019, which is after we even submitted the Mesquite applications, can be considered. But I understand that it's Mr. Brancard's position that it can be, and so that goes to weight again and not perhaps admissibility

MR. BROOKS: Yes. And my concession is that an adequate predicate was not laid for admissibility -- or may not have been laid for admissibility. Let me put it that way. Since I'm making a concession, I want to make it as narrow as necessary. And that admission was limited to Exhibits 9-B and 9-C.

MS. BENNETT: I think it was limited to --

MR. BROOKS: 9-C and 9-D, not 9-B. It did not apply to -- it didn't apply to 9-B. It does not apply to B, as in Bravo, but it applies to D, as in delta.

MS. BENNETT: And I have a series of questions that I intend to ask Mr. Goetze about those two exhibits, if that would be helpful for the examiners to revisit my objections after those two questions.

EXAMINER JONES: Let's do that. Admit them all, and then you guys ask your questions. Let's do that after lunch.

Let's break for one hour.

MS. BENNETT: 45 minutes?

EXAMINER JONES: Do you want to do 45?

MR. BROOKS: One hour.

EXAMINER JONES: Make sure everybody's back by 1:00, and we'll start before 1:00.

(Recess, 11:54 a.m. to 1:05 p.m.)

EXAMINER JONES: We admitted the Division's exhibits into all five of these cases.

But Mesquite is only admitting its exhibits into the Mesquite cases, and that was intended; is that correct?

MS. BENNETT: That was my intent.

MR. BROOKS: It was our intent to tender our exhibits into all the cases that opposing counsel had opportunity to pose objections. But did you note the exhibits that were not admitted?

EXAMINER JONES: We admitted them all. There are going to be questions that bring out deficiencies or not deficiencies.

MR. BROOKS: Okay. Fair enough. Go ahead.

EXAMINER JONES: I guess we're ready for --

Do you pass Mr. Goetze?

MR. BROOKS: Yes. I pass Mr. Goetze.

EXAMINER JONES: Ms. Bennett?

MS. BENNETT: Thank you.

CROSS-EXAMINATION

BY MS. BENNETT:

Q. Good afternoon, Mr. Goetze.

A. Good afternoon.

Q. I just wanted to make sure about why we're here today with you and with Mr. Brooks. You were here at the hearing that was less than a month ago -- I stand corrected on that -- where Mr. Neatherlin, for Mesquite, stated that Mesquite is seeking approval of these three applications; is that right?

A. That is correct.

Q. And were you here when Mr. Neatherlin testified that Mesquite is, in fact, complying with the 1.5-mile spacing requirement going forward? Do you recall that?

A. I was not aware of that.

Q. Have you seen Mesquite's recent applications?

A. I have.

Q. And do they comply with the 1.5-mile spacing requirement?

A. At this time, with 200 applications, theirs is farther down the queue currently.

Q. But you don't have any idea whether Mesquite is complying with the 1.5-mile requirement?

A. I would not have at this time. No. But I do know that their intentions were placed forward, and they have created that, so yes.

MR. BROOKS: I'm not really making an objection, just a point of correction. There is no requirement as to the 1.5 mile, just a suggestion.

Q. (BY MS. BENNETT) I'd like to refer to it from now on as the 1.5-mile screening tool.

A. Yes.

Q. So I wanted to bring to your attention a map that I don't intend to admit unless the examiners are so inclined, but it's an exhibit that, Mr. Goetze, I believe you prepared. It's a map that you prepared for another case. Earlier today you testified that you view the 1.5-mile spacing screening tool as -- as just that, right? When it comes down to it, it's a screening tool?

A. Correct.

Q. And you said -- you testified earlier today that it's your opinion that based on the 1.5-mile screening tool, Mesquite's application should be denied?

A. Correct.

Q. What I've given you-all today, before you, is a map that you prepared, Mr. Goetze; is that right?

A. Correct.

Q. When did you prepare this map approximately?

A. About two weeks, three weeks ago for the hearing.

Q. And was this a hearing for the Longwood Randy Allen Federal SWD No. 1?

A. Correct.

Q. And did you protest that hearing?

A. No.

Q. Did you deny that application?

A. No.

Q. Did you make Mr. Brooks file a prehearing statement in that case?

A. No, because I was the hearing examiner, and it was taken under advisement.

Q. And how far is the Randy Allen Fed SWD No. 1 proposed to be from the Baker well?

A. It is 1.13.

Q. So if this truly were a screening tool, a thumbs-up or a thumbs-down, shouldn't the Randy Allen have been denied out of hand like the Baker well?

A. Not until I know the outcome of Case 20472, in which case the priority of application, which makes the Baker higher on the priority, as approved by the Secretary, having primacy as far as which way that case would go. So we have an application. The Baker was filed prior to the Randy Allen.

Q. So you're saying that the Baker application is in line in front of the Randy Allen?

A. It is in a hearing. Yes.

Q. And why then would you go to hearing on the Randy Allen if the Baker application is first in time?

Why wouldn't you protest that hearing like you've done the Solaris application or the Blackbuck application?

MR. BROOKS: Objection. Again, Mr. Goetze has not filed the protest, nor has the Division simply --

(The court reporter requested Mr. Brooks speak louder.)

MR. BROOKS: Okay. Let me say that my objection is that the statement that the Baker application -- that Mr. Goetze or the Division has filed an objection to the Baker application is incorrect. What they've done is put it to hearing. The Division has put it to hearing, and Mr. Goetze has appeared as a witness.

Q. (BY MS. BENNETT) I'd like you to turn, Mr. Goetze, to Exhibit D-1 in the exhibits I prepared, page 82, in the revised materials.

MS. BENNETT: And that's page 82.

MR. BROOKS: Okay. Got it.

THE WITNESS: Yeah.

Q. (BY MS. BENNETT) There's some highlighted language at the bottom that says -- starts, "However, should the Applicant seek approval of these applications through hearing" --

A. Uh-huh.

Q. -- "the Division will take certain action." What is the action that the Division proposed to take?

A. To oppose it.

Q. So the Division stated in an email to my client that the Division does oppose these --

A. Because we felt that it was not administratively approvable based on its proximity. Therefore, the opportunity for the Applicant to come to hearing was presented to them, and we would present ourselves, as we are now, providing what we have.

MR. BROOKS: Let me correct one thing further of what I said, correcting what I said. I said the Division can merely put it to hearing. In fact, the Division intervened as a party -- and I believe in this case and I know we did in several saltwater disposal cases -- and the reason they did that because of the nature of this hearing -- nature of this whole proceeding, there was some uncertainty.

Q. (BY MS. BENNETT) With that clarification then, I would ask why the Division did not enter its appearance in Case Number 20484 and make that case go to hearing with the Division entering an appearance and providing the data that the Division has presented today?

A. Because, one, at this time it still was dependent. It still may be available for a denial. Two, the fact that, again, we have over 200 applications. Sometimes we're not perfect.

Q. I'd like to you to turn to Exhibit Number -- it's in your materials, actually. It is behind Tab Number 8, I believe. It's the orders that you included in your packet and those are behind Tab 8.

MS. BENNETT: And just to reorient everyone, the Mesquite applications were submitted in July 2018 for the Laguna Salada. Just as a reminder, the Laguna Salada administrative applications were submitted in July 2018.

Q. (BY MS. BENNETT) So let's turn to Tab 8-D, please. 8-D is the approval of the Chevron Maelstrom well; is that right?

A. That's correct.

Q. And this was done on June 7th, 2018; is that right?

A. Correct.

Q. Was the Chevron Maelstrom well closer than 1.5 miles to a Mesquite well?

A. I believe -- I don't know. I'd have to go back and look at it.

MS. BENNETT: And I'm happy to have Mr. Goetze confirm that, but I would also point out to the examiners, on the Exhibit -- I'm sorry. On 5(n), which is on page 3 of 8 of that order, it states, "The estimated small increase in the reservoir pressure...should not impact the reservoir pressures for similar disposal operations in the same formation located within a mile of the Subject Well." Does that suggest to you that there was an SWD high-volume disposal well within a mile?

A. I would not be able -- I'd have to go back and look at my records.

Q. (BY MS. BENNETT) How about Finding 5(h)? Finding 5(h) -- did you write this order, Mr. Goetze?

A. Yes, I did, very clearly.

Q. "There are no disposal wells...within a one-mile radius of the Subject Well."

A. That's correct.

Q. So at the time this order was entered, which was June 7th, only a month before Mesquite submitted its application, you were looking at a one-mile radius?

A. Correct, as well -- as well as extending it out.

Q. Where in this order does it show that you considered a three-quarter-mile radius or a 1.5-mile distance between the wells?

A. It was conversations that were being had with expert witnesses as far as what we were going to do. Not expert witnesses, but experts in induced seismicity, looking at some sort of effort to move that area of review, first of all, because Chevron went to hearing because it was one of the first cases going to a larger injection volume, as well as a larger tubing size. And with that, Chevron had also offered to include requests by the Division with regards to doing induced seismicity. So at that point, there may have been a .5, but at the same time, it wasn't a situation such that we were not looking at what was coming in, especially with the concentration of Devonian wells that were occurring between Malaga and Loving.

Q. So a month before, though, it's safe to say that you were looking at the 1.5-mile?

A. We were, yes.

Q. And that was approved, that well?

A. Correct.

Q. And it was approved closer than 1.5 miles to a Mesquite well?

A. That's correct.

Q. So is it fair to say that as of June 2018, there was no three-quarter-mile radius requirement or spacing tool?

A. It would depend on what the Mesquite well was injecting.

Q. And how is that relevant?

A. How is that relevant? We'd look at the proximity to that Mesquite well and what its design was and what it was injecting and, at that time, our early consideration to whether it had a smaller, say, 4-3/4 or it had been moved up to the 5-1/2-inch-7-inch combination. So --

Q. Did you look at that information when you issued the denial of the Mesquite Laguna Salada applications?

A. We looked at what Solaris had proposed and Intrepid had proposed for their wells, yes, in their applications.

Q. And did you put that anywhere in your denial letter to Mesquite that you were looking at volumes?

A. No. We did not put any specific reference.

Q. Turning back to some of your exhibits now, I wanted to start with Exhibit Number 2, which is the EPA work group document. Did you provide the EPA work group document to operators?

A. The posting of it was known. It is a -- it is a -- it was out there.

Q. Did you provide it? OCD, I mean, not you specifically.

A. We did not post it on our website, but we did reference it.

Q. Where did you reference it?

A. In the meetings that we were having. At that time DYC Technical Advisory Group, we were having meetings on disposal, and it was brought up and discussed there.

Q. But it was never posted on your web page?

A. No, it wasn't.

Q. Was it ever sent out to any operators?

A. It was -- the fact that we were talking about it, I assume you would know that and, therefore, its location being a public document would be available.

Q. But you never alerted any -- and by you, again I mean OCD. OCD did not put on its website that it was considering using this document to create a new policy for the Division?

A. No. It was not. It has a front-page notice to operators.

Q. When you were testifying, you mentioned that EPA informed you, OCD, to review and move forward as you deemed appropriate. And several times during your testimony, you mentioned that EPA requested that OCD come up with some induced-seismicity guidance. Is that accurate?

A. Correct.

Q. Do you have any of those communications from EPA?

A. My discussions with Phil Dellinger are not necessarily recorded, but we do contact and we are provided contacts and we have mandates come out, whether it be this one or guidance documents. We have discussions with the EPA region, and with that, they provide us with what they think, verbally, they need. We also get written requests. And at this time, the other project that was going on was the UIC exempt aquifer program.

Q. When you had verbal discussions with EPA, did you -- did EPA ask you to impose a 1.5-mile screening tool?

A. No. Their indication was to take a look at the document, review its content and provide something in your program that would address the concerns that had been identified by the work group.

Q. So this document is dated February 6th, 2015; is that right?

A. Correct.

Q. And yet as of June 2018, three years -- two-and-a-half years later -- I don't want to get sideways with Mr. Brooks on my calendaring. But

sometime later, at least more than two years later, you still hadn't adopted or put into place the 1.5-mile screening tool suggestion; is that right?

A. We had not put into a rule that type of distance.

Q. Have you ever put it into a rule?

A. There is nothing in the New Mexico Administrative Code to a specific distance between wells.

Q. So I feel like you're alluding to something there or you're suggesting that there may be something someplace else.

A. The only thing -- "alluding to" --

MR. BROOKS: Object, Your Honor. The -- New Mexico law is not subject to opinion by which this witness can be examined. It's clear that New Mexico law requires rules to be incorporated for publication in the New Mexico Administrative Code. If it's not in the code, it's not a rule. That's a clear question of law. There is no need for opinion testimony.

MS. BENNETT: Thank you. That was very succinctly put. If it's not in the regulations, it's not a rule.

MR. BROOKS: If the examiners have any questions, they can ask counsel.

Q. (BY MS. BENNETT) So -- but I -- that's my bigger question here, is that the 1.5-mile screening tool has never been -- the Division has never made that publicly available in any kind of digestible format to any operators? It's not on your website, for example?

A. No. It was, again, held in discussion and offered individually.

Q. Offered individually?

A. Uh-huh. With emails from applicants.

Q. At the time of denial?

A. After the time of denial. I believe we do have an email conversation with several and prior to.

Q. Did you ever email Mesquite alerting them to the fact that there had been a change and it was a 1.5-mile screening tool now?

A. I did have a discussion with one of your representatives on November 7th, 2018.

Q. After the administrative applications had been filed?

A. That's correct.

Q. I wanted to look at page 9. When you testified, you said there were two -- and I'm on page 9 of the EPA work group discussion document. So on page 9, you said there were two items that stood out and those were -- and I forget what they were exactly,

but --

A. Communication with basement rocks and the importance of porosity and permeability within the injection strata.

Q. And that's actually on --

A. Page 11.

Q. Okay. That's what I thought.

But looking on page 9, the EPA identifies three key characteristics related to potential injection-induced seismicity that may lead to fault slippage. Do you see those three considerations?

A. That's correct.

Q. And would you mind reading those considerations into the record?

A. "An increase in the formation pore pressure from disposal activities; (2) a fault (or zone of multiple faults and fractures) optimally oriented for movement, located in a critically stressed region, of sufficient size, and possessing sufficient accumulated stress/strain, such that fault slip and movement would have the potential to cause a significant earthquake," referenced as a Fault of Concern; and "(3) a permeable avenue (matrix or fracture permeability) allowing the pore pressure increase to reach the fault."

Q. Now, when you prepared your denial of the

Laguna Salada applications, did you undertake any of that review for that site-specific area?

A. No, I did not.

Q. Did you prepare any sort of information like that for a site-specific-location review today for this hearing?

A. No, I did not.

Q. You were here when Mesquite's experts testified at the last time this hearing was convened?

A. Correct.

Q. And do you recall there was testimony that there is no fault of concern in the area?

A. That is what -- based on publicly available information, yes.

Q. When you were talking about the major takeaways of the sort of things that you looked at on pages 10 and 11, did you consider any of these when you specifically looked at the Laguna Salada wells or the Baker wells when you denied those applications administratively?

A. No.

Q. How about today? Did you provide any information today about the Laguna Salada wells and the Baker wells specifically with respect to the geologic stress considerations?

A. Not the geologic stress considerations.

Q. "Geophysical Data"?
A. No.
Q. "Communication with Basement Rock"?
A. Consideration was given to that and its proximity.
Q. Where is that in your exhibits?
A. Oh. Just in thought.
Q. In thought. So that's a no?
A. No.
Q. "Importance Of Porosity And Permeability Of Injection Strata." Did you look at that for the specific location we're talking about?
A. Yes. That's correct.
Q. And where is that in your --
A. I did not provide any testimony for that.
Q. How about "Petroleum Engineering Politics For Evaluating Induced Seismicity"?
A. It would be difficult considering the limited information in the area, but no, I did not offer any testimony to that fact.
Q. So the five areas that EPA recommends to regulate or review and provide technical analysis of, you did not do for this case today?
A. What a regulator would consider and provide an assessment, no.

Q. And did you provide an assessment of any of these five for the hearing today?

A. I did not.

Q. Did you provide any of these five when you denied the Mesquite applications?

A. No. The original Mesquite applications were based on a lack of this information in the sense that if we were to go to hearing, I'm sure this would be information brought forward.

Q. That brings me to a question I've been pondering all these days.

MR. BROOKS: Excuse me. What page are you on when you were talking about the --

MS. BENNETT: It's 10 and 11, behind Tab 2.

Q. (BY MS. BENNETT) All these long days I've been thinking to myself, Mr. Goetze, why didn't you just email -- instead of denying it outright, why didn't you just email Mesquite and ask them to provide you with the information that Mesquite was willing to and has now provided at hearing?

A. At that time, because of the pressures of work, as well as not having a good model as to what we should do, the Division responded based upon the application and on the merit of its own application.

Q. Did you -- I thought you said, though, you used

the 1.5-mile as a screening tool?

A. That's correct.

Q. So am I right that that's a thumbs-up or a thumbs-down?

A. It may be -- well, let's take that back. The .75 provided an optimum available information screening device and, with that, the abilities to make a decision with the application and, with that, a decision as to whether it could be administratively approved or not is what we used.

Q. Okay. I don't know that you actually answered my question, but we'll just move on from there.

Let's see. On page 25 of that same report, you said -- again, you were talking about the confining layer here.

A. Uh-huh.

Q. And you spent a lot of time in your testimony actually talking about the confining layers, the Ellenburger, the confining lower layer, I guess I would call it. And that doesn't take into account the Montoya and the Simpson, does it?

A. The confining layer has always been identified as the Montoya and the Simpson. The Ellenburger, in our discussion, is shown as being a conduit based upon its lithology as a probable conduit to the Precambrian.

So --

Q. Okay. So that helps me understand that a little bit better. So you weren't suggesting that the Ellenburger is a defining layer.

A. No, no, no, no.

Q. You're acknowledging there are actually two other formations that are a defining layer?

A. There are two formations of which one we permit to be drilled into.

Q. The Montoya?

A. Correct.

Q. And how deep can folks drill into the Montoya?

A. We request a maximum of 100 feet.

Q. Is that available in any rule?

A. No. But that is based upon a tooling for running a log tool suite so that you can see the contact.

Q. And how do people find out that the Division is only allowing folks to drill 100 feet into the Montoya?

A. It is included in the order.

Q. So there is no prenotice of that?

A. Not when it comes to conditions of approval.

Q. When did you start -- what did OCD decide to not allow folks to drill into the Montoya more than 100 feet?

A. Oh, it goes back, I would say, middle of 2018.

Q. And there's been nothing on your website about that?

A. Not -- because it's issued order by order, and it is reflective of an industry standard of having to be able to correlate and know if you are in the correct interval, which is what the permit is issued for.

Q. Would you say that the Division's decision to only allow drilling into 100 feet of the Montoya is designed to protect against communication with the basement?

A. It is part of the effort to isolate and make sure the Montoya contributes.

Q. So the Division has already undertaken several regulatory steps to reduce the likelihood of communication from the injection layer to the Ellenburger and beyond?

A. I believe my exhibits, which included the letter to the Director, did specify that.

Q. Is the frac gradient part of that or the frac limited, the .2?

A. The .2? As in --

Q. The thing that you multiply times the depth to get the maximum psi at surface. I'm not asking if that's part of the letter to the Director, but is that

part of the controls that the Division has put in place to protect against fracturing?

A. It is a tool that was put in place by our primacy agreement with the EPA and --

Q. That's fine. I just wanted to make sure that I understood that that was another control that the Division has put in place.

A. It is also found in our downhole commingling, too.

Q. I wanted to turn back to ES-2 of the EPA report. It's page ES-2 in the Executive Summary. And I think you might have touched on this, but I can't remember. But in the first full paragraph, there is a sentence that starts "The Class II UIC program does not have regulations specific to seismicity...."

A. Is that ES-2, or are you just looking at 3?

Q. I'm looking at ES-2. It's in the full first paragraph. The paragraph starts "Disposal wells are one of a...."

A. Oh, yes.

Q. And about -- I'm just going to skip to the chase. I'm going to read it into the record rather than make you find it. But it's the last sentence. "This report is not a guidance document and does not provide specific procedures, but it does provide the UIC

Director with considerations for addressing induced seismicity on a site-specific basis...." Is that accurate?

A. Correct. That's what it says.

Q. Did you consider induced seismicity on a site-specific basis for the Mesquite Laguna Salada wells?

A. When they were first denied?

Q. Yes, when they were first denied.

A. No, I did not.

Q. Did you for the hearing today?

A. I have reviewed their testimony but not -- I've offered nothing.

Q. You've offered nothing that would show that you considered or addressed induced seismicity on a site-specific --

A. Not for this.

Q. And not for the Baker well?

A. Not for the Baker.

Q. The next sentence down says, "The working group" -- and I am quoting again -- "noted that no single recommendation addresses all of the complexities related to injection-induced seismicity, which is dependent on accommodation of site geology, geophysical and reservoir characteristics."

Does your 1.5-mile screening tool consider site geology?

A. As we apply it? As -- as was used for the denial?

Q. Yes.

A. It did.

Q. How did it?

A. How did it? We looked at the information, again, provided at hearing and found that at that .7 mile, we were starting to see cumulative effects of injection in the models.

Q. You're talking about the Chevron hearing?

A. Matador, Chevron.

With that as a preliminary concept, we went to look at the ability of the Division to have some sort of device, as prudent as it may be, to help resolve the application -- the density of applications which have been coming.

Q. But you didn't look at any site geology for the Mesquite wells?

A. It is not site-specific.

Q. Oh.

In this study and elsewhere, you said that these materials support your conclusion that applying the 1.5-mile screening tool is appropriate. Where in

the EPA document does it say 1.5 miles?

A. It says the spacing of wells should be considered.

Q. Does it say 1.5 mile is protective of the environment?

A. The U.S. EPA document is for all regions, from East Coast to West Coast, from Ohio to Pennsylvania to Oklahoma to Texas to New Mexico. Again, we drew upon the best testimony at the time to make a decision.

Q. And so would you say then that the EPA document covers the Raton Basin, too?

A. Yes, it does.

Q. So does it -- anywhere in the EPA document, does it say you should look to Texas to see what's happening in Texas and decide whether that applies in New Mexico?

A. Well, this brings about a little bit of a consternation as a professional geologist. Having had hearings and testimony by expert witnesses with regard to, say, geology of the Texas side of the Permian Basin being entered as exhibits to demonstrate what is happening in the Delaware on the New Mexico side, as a geologist, you look at other people's situations, and we do consider them. So Texas and Oklahoma have provided us as a best example of what is happening.

Q. Based on those areas' geology?
A. They're unique.
Q. And the formations into which those wells are injecting?
A. The Texas side, we do share formations.
Q. But some of the documents that you cited were also injecting into the Ellenburger, which the Division has said is a no-go here, right?
A. We did, but, again, we have approved Ellenburger injection previously.
Q. Previously.
So you talked about the distance between wells that's on page 34 of the EPA handbook and you said there were three approaches -- operational, monitoring and management -- and you looked primarily at the operational approach? There are about -- I'm just counting, one, two, three, four, five, six, seven, eight, nine -- ten bullets there.
A. That's correct.
Q. And out of those ten, you picked "separate multiple injection by a larger distance...."
A. That's correct.
Q. And you decided to apply that bullet uniformly -- well, quasi-uniformly?
A. Quasi-uniformly and temporarily because we

don't have a program in place that addresses induced seismicity.

Q. Temporarily?

A. Well, at this point we were moving forward with it, and so we are using it as a tool.

Q. So are you saying that next week you could change it to a mile radius, and everyone here who has wells -- applications pending where there's going to be now two miles, that's fine?

A. Actually, it went in the other direction.

Q. I know it didn't this time, but I'm asking you if you could do that next week.

A. Based on my scientific knowledge, I would not expand. As a matter of fact, I would take a different approach.

Q. What approach would you take?

A. Having a program in place.

Q. Through a rulemaking?

A. Whatever management decides.

Q. So this is a management decision about whether to have a rulemaking or not?

A. Part of it is, yes.

Q. What's the benefit in your mind -- you said earlier -- you testified that you've been involved in rulemaking. What's the benefit of having a rulemaking?

A. The benefit of rulemaking would take and provide an ability for those parties wishing to -- it would put it more defined.

Q. And would the regulated entities have an opportunity to participate in that?

A. Normally the regulated entities are the ones who propose it.

Q. And the regulated entities would propose it? Is that what you're saying?

A. No. The regulators would propose it.

Q. Yeah. And then the regulated entities, like Mesquite, would have an opportunity to participate?

A. That's correct.

Q. And then it would be a formal decision, published, subject to hearing, subject to notice and comment, that everyone would know about?

A. Correct.

Q. That's not what happened here, though?

A. No. There was no notice to operators.

Q. How about -- Mr. Brooks asked you if the Division can do things by rules and orders, and the statute does say the Division can do things by rules and orders. Is there an order that you can point me to that says the Division is now imposing a three-quarter-mile radius?

A. No.

Q. And I'd like to contrast that with your exhibit that you provided, Exhibit 9-E. Exhibit 9-E is a form of an SWD order apparently that the Division came up with.

A. That's correct.

Q. And it has three new criteria in it?

A. No. Those are requests for information. And if the applicant wished not to, they did not. You'll find them without that. It is possible for those who follow us will have an idea to what level of information was provided for that application.

Q. It doesn't say anything about a three-quarter-mile radius here, does it, in the template?

A. No, it does not.

Q. But it does include other suggestions that were made around the same time?

A. That's correct.

Q. So there is no way anyone would know from reading this form of order or orders that have been issued since about the three-quarter-mile radius?

A. Other than individual contacts and discussion with me.

Q. Discussion with you?

A. And Mr. McMillan.

Q. You know, one of the things you talked about behind Tab 4 -- and I apologize. I'm jumping around a little bit here. You identified a whole bunch of exhibits about Oklahoma --

A. Uh-huh.

Q. -- and Oklahoma's new process.

A. Right.

Q. One thing -- if you wouldn't mind turning to Tab 4. One thing that struck me about Tab 4 is the amount of publicly available information that Oklahoma gave.

A. That's correct.

Q. And when I'm looking at this, I see, February 24th, 2017, a news release, "Looking Ahead - New Earthquake Directive Takes Aim at Future Disposal Rates." Does the OCD put anything like this on the books?

A. I believe you would have to ask the Director and staff. I am not that. I am the UIC technical advisor.

Q. To your knowledge, as a UIC technical advisor, has anyone asked you to prepare any paper or news release to be put on the OCD website?

A. Not currently, not in the history.

Q. Has anyone asked you to put anything about the three-quarter-mile radius together to put on the website?

A. No, they have not.

Q. And when you look at this -- I mean, there is --

A. It's quite extensive. It's quite extensive.

Q. -- three or four years' worth of material that the --

A. Uh-huh.

Q. -- Oklahoma -- whatever they're called -- Corporation Commission has put on their website.

A. Uh-huh.

Q. Contrast that with apparently none on the OCD website, to your knowledge?

A. To my knowledge.

Q. You know, earlier you talked about collaborating with Texas, and you said that Texas is like a really great model for us to follow, New Mexico, or at least they have -- you said Texas has a program that's been thoroughly investigated and developed.

A. Right.

Q. Does Texas have any spacing requirements?

A. No. Texas has a much different system.

Q. So no spacing requirements?

A. No.

Q. You mentioned that you've been collaborating with Texas for five months.

A. Uh-huh.

Q. Have you invited any regulative entities to collaborate with you and Texas for the past five months?

A. Actually, it's the regulated entities that have come and approached us. That would be XTO, Chevron, Marathon. All these folks have come to us with the recommendation of SICR and have provided us with what you see as Exhibit 11.

Q. So you got that from Marathon and Chevron and XTO?

A. And their consortium, yes.

Q. But have you invited any other SWD operators like Mesquite or NGL or Solaris or Blackbuck to participate in your communications with the Texas regulators?

A. We have not had meetings of the UIC work group for some time.

Q. So that's a no?

A. That's a no.

Q. You know, I don't know who has my Exhibit 11. I don't seem to have it anymore, but pretend for the moment that -- okay. I've got it.

So we already talked about how there is no 1.5-mile spacing requirement; is that right?
A. That's correct.
Q. And they had a seismicity screen that you talked about.
A. Uh-huh.
Q. And when I looked at Exhibit 11, it says, "An earthquake event" -- and I'm looking at page 9 of Exhibit 11. "An earthquake event of 2.0 magnitude or greater within the 9.08-kilometer area of review will trigger the seismic review." Does that mean that Texas -- in your opinion, does that mean that Texas only undertakes a seismic review if there is an earthquake greater than 2.0 in the area of review?
A. That's correct.
Q. Did you -- even just using publicly available information, did you consider whether there had been an earthquake event of 2.0 magnitude or greater within 9.08 kilometers of the Mesquite wells?
A. No, because I didn't have that.
Q. You don't have that what?
A. I don't have this as an adoptive procedure yet or have not gone to that point, to the ten square miles, which was adopted by the Texas Railroad Commission.
Q. You were here when Mr. Reynolds testified at

the last hearing, right?

A. Correct.

Q. Do you recall that he used the ten square miles?

A. That's correct.

Q. 100 square miles --

A. The 10-by-10 --

Q. Yeah, 10-by-10.

A. -- which the Texas Railroad Commission uses.

Q. Yes.

So is it fair to say -- and I can ask Mr. Reynolds this, but you might just recall that he followed the Texas Railroad Commission process.

A. Mr. Reynolds has presented testimony in many cases, and he does follow a very thorough procedure.

Q. And did he do that for the Mesquite cases?

A. Yes, he did.

Q. So he followed the exact approach that you consider as --

A. What we are --

Q. -- thoroughly investigated and developed?

A. What we are looking at as being a method for us to use.

Q. And he used that already?

A. That's correct.

Q. For these exact wells?
A. Correct.
Q. And he identified no faults of concern?
A. Based on the publicly available information, yes.
Q. I just want to qualify that. It's not just publicly available information that Mesquite was using, is it? They were using information from NGL's seismic monitoring network?
A. But they were not using any 3D seismic or 2D seismic that I was aware of.
Q. Is that how you define publicly available?
A. No. That's not publicly available.
Q. No. But, I mean, is that the difference between publicly available and not publicly available, is 3D versus a private network --
A. No. But what you're looking at -- the -- the concept of using 3D seismic to improve your understanding of what faults are in the Precambrian is one of the issues that was raised in several papers, is how accurate of the information you have and putting it into the model.
Q. Does the Texas Railroad Commission require 3D seismic modeling?
A. Depending upon what level of concern they have.

Q. Would you have to be above 2.0 magnitude to get there?

A. You would have to have something to motivate you up.

Q. Was there any evidence that you saw at the time of the denial to motivate you to think that there was something higher than 2.0 in that area?

A. I did not have this information at the time.

Q. Even publicly available information? I mean there's USGS --

A. Even publicly available information for the process which they use.

Q. Hold on a second.

A. Yes.

Q. So are you saying that you didn't even look at publicly available information for seismic data when you denied the Baker -- I'm sorry -- the Laguna Salada applications?

A. The information provided through New Mexico Bureau was looked at. I did not look at TexNet at that time. No, I did not, nor did I apply this information since I did not have it at the time.

Q. Right. You didn't have this information at the time, did you?

A. No, I did not.

Q. I think that was one of my objections to using the exhibit, but I won't go into that any more.

Does Texas have any kind of spacing requirement in its model -- I mean in its --

A. In its UIC program?

Q. Yeah.

A. No, it does not.

Q. Does Colorado?

A. No, it does not.

Q. Oklahoma?

A. It uses a system which regulates based upon proximity, so --

Q. The net volume?

A. As well as proximity.

Q. Where is that in the materials, that Oklahoma regulates based on proximity?

A. Well, it would be in the -- looking at the reduction plan, and in the Logan trend proper, they do take into account proximity of disposal wells. They also consider it as a part of their red, yellow and green light, based upon what I've seen.

Q. Is that triggered by a specific location instead of the Logan?

A. They look at a collective set of wells.

Q. Around a specific location?

A. That's correct, around an event.

Q. Around an event?

A. That's correct.

Q. And there haven't been any events in the area of the Mesquite wells, have there?

A. Based upon information, none.

Q. So is it fair to say that -- well, I'm not going to ask that question.

A. Remember, I'm not a seismologist.

Q. I know.

Let's see. A lot of the materials that you prepared -- not prepared, but provided in your exhibits all relate to either Oklahoma, Texas, other states, or those that do relate to New Mexico are based on enhanced recovery, secondary recovery; is that right?

A. As well as Dagger Draw.

Q. And how far away from the Mesquite wells is Dagger Draw?

A. Dagger Draw is to the north, the potash area, so it is --

Q. About how many miles would you say?

A. Ten to the Lagunas.

Q. How about more like 40?

A. 40.

Q. Okay. How about the WIPP project, the Waste

Isolation Pilot Plant, do you know how far that is to the Mesquite wells?

A. Yes, I do. The Laguna Salada wells are 12 to 12.8 miles. The Blackbuck-Solaris are 9 to 9.5 to the southeast, and the Baker is 9.1 or 9.2 miles to the south of the WIPP perimeter.

Q. So ten-ish?

A. Uh-huh.

Q. And how about from the potash areas? I didn't really understand your concern about Mesquite somehow affecting the potash --

A. Well, if you have a seismic event -- and the mining that is done there is critical -- pillar [sic], you can impact the supports which hold the back of the mine up.

Q. And how far are the nearest potash --

A. Workings?

Q. Yeah.

A. To the Baker, I would say six -- 16.

Q. 16?

A. Uh-huh. We have workings in 23 South, 20 East, and then down to 23 -- excuse me -- 22 South, 30; 23 South, 30; 23 South, 29, based upon the BLM.

Q. Okay. Earlier today Mr. Brooks said that you need to take into consideration induced seismicity

because it's an impact to the public's health when houses shake. Is that a resource protected by -- is that a U.S. underground source of drinking water, people's houses?

A. No. That's under our general rules, is to protect the environment.

Q. So would you say that your regulation of UICs is limited by or is defined by the MOU and your primacy agreement with the federal government?

MR. BROOKS: Objection to that question. It's asking the witness to comment on the source -- on a legal issue of what the grounds for regulations are under New Mexico law.

MS. BENNETT: I was under the impression that Mr. Goetze was an expert in the UIC program, and he himself testified about the memorandum of understanding and the primacy agreement earlier today and has, in fact, included it as an exhibit.

MR. BROOKS: Well, I didn't object to the question about the UIC program and the primacy agreement. I objected to the question asked of Mr. Goetze whether or not the OCD has also -- New Mexico law.

MS. BENNETT: So he doesn't know the answer to that?

MR. BROOKS: Best to question him.

EXAMINER BRANCARD: I think he already answered it on the previous question.

THE WITNESS: Probably.

MS. BENNETT: That's fine.

MR. BROOKS: My contention would be that the -- the OCD, when it is acting as -- as having primacy under the Safe Drinking Water Act is regulating injection. It also regulates injection and does not have different procedures when it is exercising its power under the Oil and Gas Act. So the regulation of injection is a dual-function regulation.

MS. BENNETT: If I could rephrase my question.

EXAMINER BRANCARD: Okay.

Q. (BY MS. BENNETT) Are you familiar with the OCD injection regulations?

A. Under the New Mexico Administrative Code?

Q. Yes.

A. Yes.

Q. And are you familiar with Rule 19.15.26.6? It's a rule within the injection --

A. Yes. I know what it is, but I don't have a specific reference of it in front of me.

Q. I'll read it, and I will suggest to you that I

have copied it verbatim from the regulations. It says that "the effect of the UIC regulations is to" -- and I quote -- "regulate injection wells under the Oil and Gas Act and to maintain primary enforcement authority for the Safe Drinking Water Act." Is that the objective of the UIC program -- New Mexico UIC program?

A. So far, yes.

Q. And how about New Mexico Statute Annotated 70-2-12(B)(15), which is the Division's authority? Are you familiar with that statute?

A. Correct.

Q. I'm going to read something again that I will say to you is a quote from the statute. You can check me. "The Division is authorized to" -- and I quote -- "regulate the disposition of water, produced or used in connection with the drilling for or producing of oil and gas." And I'm entering an ellipses here. And it says, "In a manner that will afford reasonable protection against contamination of freshwater supplies designated by the State Engineer." Does that sound about right to you?

A. Correct.

Q. Where in the Baker denial did you -- I'm sorry -- the Laguna Salada denial or today even have you identified freshwater supplies designated by the State

Engineer that will be affected by the injection in these wells?

MR. BROOKS: I don't exactly have an objection to that question except to the extent that it suggests that the authority under the New Mexico rules -- under the New Mexico Oil and Gas Act is limited to Section 15 of 19. -- of 70.2 -- 70-2-12B and also includes -- and it also includes another subdivision -- at least one other subdivision of the same section of the statute and authorizes the Division to regulate the disposition of oil in place for the protection of the -- for protection of the public health and the environment.

MS. BENNETT: Okay.

EXAMINER BRANCARD: Well, my concern with the question is not that. It's that you keep referring to the denial, which is not at issue here. What's at issue here is your application.

Q. (BY MS. BENNETT) Okay. Where in the materials today did you identify a freshwater supply designated by the State Engineer that will be impacted or potentially impacted by the drilling of the injection into the Laguna Salada wells?

A. I have not.

Q. And you didn't for the Baker wells -- with the

Baker well either, did you?

A. I have not.

Q. Where in your materials today did you identify any place where the Baker well will affect correlative rights of mineral interest owners?

A. If all was processed accordingly and with notice given, chances are both applications -- well, all three applications will have successfully noticed what we would potentially feel would be an individual with correlative rights.

Q. Okay. I'm going to ask the question again because I'm not sure I understood your answer.

A. Well, with the administrative review, we are asked -- as we go back to the exhibit, we asked the parties to do a one-mile notice, and so there has never been an issue or a question. And in most cases, asking or requesting above the one-half mile, as we had proposed or have in the primacy agreement, we always overnotice as a means of protecting correlative rights.

Q. So I guess just to summarize -- and tell me if I'm incorrect here -- you're saying that the notice requirements protect correlative rights?

A. That's correct.

Q. And there was no indication that Mesquite did not comply with the notice requirements?

A. We didn't with the original application either, so --

Q. So there is nothing in your materials today that would suggest there is a potential impact to correlative rights?

A. We have provided proper notice, and we feel that that was adequate.

Q. So that's it?

A. Yes.

Q. Thank you.

I wanted to look at Exhibit -- it's behind Tab 7. It's Exhibit 7-D. It's the Snee and Zoback paper, I believe, and it's on page 132 of that exhibit. You quoted from this exhibit.

A. That's correct.

Q. And you talked about how there are -- the stress field is complicated, changes in the stress field are coherent and mappable, and then -- are you there?

A. Yes.

Q. Okay. It's on page 132, behind Tab A [sic] of the Snee and Zoback paper. If only these were consecutively paginated.

(Laughter.)

Q. 7-D. "Operators wishing to use the FSP tool to screen sites for fluid injection should use detailed

fault maps that are specific to the injection interval" --

A. Correct.

Q. -- "the underlying basement, and any intervening units, which take into account geometric uncertainties."

A. Uh-huh.

Q. Did you run a fault slip analysis for today's hearing?

A. No, I did not because I'm not a seismologist.

Q. Did you consider -- did you prepare or look at any detailed fault maps of this area?

A. No, I did not.

Q. Were you here when Mr. Reynolds testified?

A. Yes. I was here when Mr. Reynolds testified.

Q. And he used the fault screen -- fault slip probability tool to screen those sites, didn't he?

A. We used the Stanford model, which we've accepted as a viable documentation for assessments.

Q. And he looked at the -- he prepared detailed fault maps specific to the injection interval, and he looked at the basement and intervening units and took into account geometric uncertainties?

A. I would defer to his discussion.

Q. Okay. But it's fair to say that he undertook a

fault slip probability analysis that the Stanford folks, that you cited to, contemplated?

A. He provides a good demonstration of information using the fault slip model. He provided an accurate depiction of what we asked for, as well as the information currently being required on many applications.

Q. In your opinion, based on what you've reviewed -- you said you reviewed the testimony and the exhibits that Dr. Zeigler --

A. Uh-huh.

Q. -- prepared and supplied in the prior duration of this hearing?

A. Correct.

Q. And she concluded that there would be no impact to freshwater resources based on the injection if injection was approved in these wells? Do you recall that?

A. That's correct.

Q. Did you prepare anything today that contradicts her?

A. We've never had an issue with that. There was always a basis of well construction.

Q. So you've never had -- you're not taking issues today with the fact that these three wells as proposed

won't impact freshwater resources?

A. I would take a look back at Solado, but I believe the well constructions were typical of wells in the area.

Q. And, you know, earlier you spent a lot of time talking about the Ellenburger, and we talked about this a little earlier. But aren't all of the SWDs that are being proposed right now, aren't they all above the Ellenburger? If there are concerns about the Ellenburger, are you going to stop issuing SWD permits because you can't -- you don't have enough information? I mean, that's sort of what I took away from your discussion of the Ellenburger earlier.

A. We are receiving as many as ten applications a week. Each of them will be required to log, and with that logging, a definitive mapping would increase. Right now I have several wells where bottom-hole determinations are irregular at best and have not been correlated properly. So the issue gets to be, as we accumulate these wells, just where is that bottom and where it is in relationship to the Ellenburger.

Q. But there is still the Simpson and the Montoya between the injection interval and the Montoya -- I'm sorry -- the Ellenburger?

A. There is the Ordovician. Yes.

Q. Earlier today you talked about the order where you denied Mesquite's application to increase the tubing size?

A. That's correct.

Q. Do you remember in that order that you -- and maybe you do remember; maybe you don't. But I'm going to read to you from the order. And I'm happy to hand this out.

A. Uh-huh.

Q. But your paragraph number nine, "The Division supports the use of the Devonian and Silurian Formations as suitable disposal intervals to lessen the potential impact on production of hydrocarbon resources." Is that still your position?

A. Yes, it is.

Q. And so your concerns earlier today about the lack of information about the Ellenburger and lack of well controls, that doesn't undermine your statement -- apparently continuing statement that the Devonian-Silurian Formation are suitable disposal intervals?

A. The Division is continuing with this effort.

Q. I was also intrigued by something you wrote in this order. In paragraph ten, you noted, "UIC Class II wells" -- and this was written March 30th, 2017. "UIC

Class II wells are not subject to any spacing requirements" --

A. That's true.

Q. -- "as described in Division Rule 19.15.15 NMAC, and the Division is not statutorily obligated to protect the correlative rights of operators with regards to produced water disposal unless such injection activities impair an operator's ability to produce hydrocarbon resources."

A. That's correct.

Q. So this was written March 30th, 2017, a year and a half after you received the EPA working group document?

A. That's correct.

Q. And at that time, a year and a half later, you still hadn't imposed any spacing requirements?

A. At that time we weren't getting over 200 applications in six months.

Q. At that time had you imposed any spacing requirements?

A. No, we had not. We just looked at it.

Q. So between March 30th, 2017 and June 2018, you still hadn't imposed a three-quarter-mile radius; is that right?

A. That's correct. We were having meetings on it.

Q. And who was invited to the meetings?
A. It was a work group, which Mesquite was a participant.
Q. When you decided on the three-quarter-mile spacing screening tool, were you in a meeting when you decided that?
A. It was a result of a meeting.
Q. Who was at that meeting?
A. The exhibits provide you with that.
Q. So that's the Exhibit 9-C --
A. Yes.
Q. -- your own notes?
A. Uh-huh.
Q. Mesquite isn't identified as an attendee on that list?
A. No, they were not. But I did not make the list.
Q. Who did?
A. I don't know.
Q. So you don't know who made the list --
A. Well, I mean, the Director and the Secretary are those who initiated the work group.
Q. Right. But those are your notes of the meetings, aren't they?
A. That's correct.

Q. And so you're saying your notes don't accurately reflect the attendees of the meeting?
A. No. It does.
Q. But you didn't say Mesquite was at the meetings?
A. No. That was -- there is a whole year of meetings going --
Q. Oh.
A. -- and they are email-transcribed. They are -- XTO -- I mean, we had over 30 participants for over a year and a half going round with the discussion about the Delaware Mountain Group, as well as the push towards Devonian. So --
Q. Did you in that year and a half of meetings -- you said those are email-transcribed. So you have copies of the emails relating to each of those meetings?
A. Yes. We had meetings in here, in Porter Hall.
Q. At those meetings did you discuss the three-quarter-mile spacing requirement?
A. We talked about what was best. In view of the demands placed upon the Devonian, one of the subjects considered was spacing.
Q. Did you talk about the three-quarter spacing -- three-quarter-mile spacing?
A. This far ahead of what we were seeing at that

time, we had no information on the area of influence.

Q. So you did not?

A. No.

Q. So your notes reflect, though, that you were considering the three-quarter-mile spacing requirement at that time?

A. At the end of 2018, we had come to that conclusion, that this would probably be best based upon what we knew at the time.

Q. When you say at the end of 2018, was that like November 2018? December 2018? Your notes are dated December 2018.

A. Yes. That's right. Meetings were held from July through August, and they were predated by as much as six months of conversations between many parties, including NMOGA. We had representatives from NGL. We had representatives and discussions with 3Bear. So --

Q. So, again, though, the Mesquite applications were submitted in July 2018, and you're saying that you hadn't even kind of started talking about or moving towards the three-quarter-mile radius until December 2018, six months later?

A. We were looking at one mile.

Q. Three-quarter mile six months later, according to your notes?

A. Going from one mile to three-quarter mile.

Q. Six months after their application?

A. No. We were looking at one mile before their applications were submitted.

Q. Does anybody know about that one mile besides the working group?

A. At the time we didn't really put it into any type of screening, so it was only discussion at that time.

Q. You mentioned the Chevron hearing as sort of a basis for this .75-mile radius?

A. There were several things. Matador --

Q. Is that in the record?

A. Yes.

Q. Is it in your exhibits today?

A. Yes.

Q. Is that Black River?

A. That's right.

Q. How about -- so -- and I'm going from memory here, and you can correct me if I'm wrong. But the Black River order says that based on a technical review, the fluids will expand out no more than a half-mile but less than a mile over 20 years.

A. Uh-huh.

Q. And the Chevron order says more than a

half-mile but less than a mile over 30 years.

A. Uh-huh.

Q. So you're looking -- you're imposing a 1.5-mile spacing requirement today to control impacts that may occur in 30 years. It isn't even -- they don't even say in the exhibits that's it's a .75-mile radius in 30 years, do they?

A. To put a $13 million well in and then come back to an operator and say that you're too close is not a good best practice management.

Q. Is that your responsibility or the operator's responsibility to make that decision?

A. I guess if an operator wishes to spend their money, they shall do.

Q. I'd like to turn to 70, please.

A. What are we looking at?

Q. I'm sorry. Just a second. Oh, this is the one that I'm looking for, 3-D, and this is the Walters, Zoback, Baker, Beroza report. On page 11 of that report, it states, "The standards used by individual projects for traffic light systems would be most effective if they were tailored to a site-specific and dependent on the risk assessment, rather than fixed for all circumstances." Do you agree with that?

A. I do now.

Q. You do now. What does that mean?

A. What does that mean? Again, in the presentation of our information, we have come to understand greater, through discussion and with applications by such operators as NGL and with participation of other NGOs, that there always has and always would be a greater scope of what was needed in the decision-making process, which we don't have in place. So yes, there is a lot more consideration now having gone through this last six months, last year, as to the use of a fault slip model, as well as the ability to see what we have as good information subsurface-wise.

Q. So you would say that standard that is fixed for all circumstances is not the right approach?

A. What we would provide is the opportunity based upon the best experiences, some sort of pathway as using the fault slip model, as using information that normally we would not ask as a possibility to resolve issues about induced seismicity.

Q. Let's look at page 16 of that same exhibit. I think this statement on page 16 nicely summarizes my concerns here. On page 16, there is a summary. And this is still the Zoback paper I was just talking about, 3-D -- page 16, 3-D.

A. Fire away.

Q. Okay. The summary states, "To date, there are many different guidelines, regulations and studies that have been published or put into practice. Many of these are 'ad hoc,' prescriptive and reactionary." Would you consider the 1.5-mile screening tool reactionary? You were reacting to the experience that you saw in Oklahoma and Texas and the amount of applications you were receiving?

A. I would not say it's reactionary. I would say it was the best thing we had at the time with the information available.

Q. So it was ad hoc?

A. 2015, this paper was written. And our imposing of some sort of filter -- this is what we use the hearings for. So we based it upon what we saw at the hearings as an area of influence form the wells over the life.

Q. Again, though -- I'm sorry to keep harping on this. But can you show me anywhere in the orders that you've prepared that show a .75-mile area of review is required -- or radius is required? Has there been any testimony that shows .75 miles?

A. Well, a .75 is where we think the additive effects of injectionable [sic] series of wells over time is what we were looking at. What we were asking for at hearing is one-mile area of review for wells that penetrate and one-mile area of notice.

Q. You mentioned earlier that you recommended to the Director that the Mesquite Laguna Salada applications be denied. Is that true?

A. All things that go through the Engineering Bureau are presented to the Director for denial or approval or issuance of --

Q. Is there any communications that you have showing that you presented this to the Director for denial?

A. None other than just a cursory recommendation by conversation.

Q. So you recommended that these $10 million, $11 million wells be denied based on a cursory conversation with the Director?

A. If I had to put down every sheet of paper -- or every discussion, I think we would really be slowed down to the point where nothing would get done.

Q. Did you -- but you didn't write down anything?

A. No. We have conversations. We have meetings, and at the meetings, you present your findings.

Q. Are there any notes of the meetings?

A. No.

Q. So it's pretty much -- there's no transparency

here for an operator like Mesquite to understand -- other than your denial and other than what we're here today with, which is nothing site-specific, there is no real transparency for an operator like Mesquite?

A. Well, my communications with Melanie Wilson and your consultant, yes, there were opportunities, and the subject was brought up with the Laguna Salada because the Laguna Salada No. 7, I believe, had raised concerns with the Intrepid back line [sic] and then later Solaris.

Q. What is the status of that Intrepid well? Earlier today you said it was still active.

A. It is still an active order.

Q. But haven't they suggested or submitted something that they want to have a change, and it was denied?

A. No.

Q. Really?

A. Solaris?

Q. Yes. The --

A. The Intrepid?

Q. Yes.

A. The Intrepid stands as was approved. Maybe they're going to upsize the tubing?

Q. Whatever it is, it was insufficient and,

therefore, denied. And I understand that --

A. You'll have to enlighten me then.

Q. Yes. I'll find that in my materials.

But I understand it's still an active permit, but you're basically holding Mesquite hostage while this other company -- because they have requested to do something and it's been denied, and yet Mesquite can't put in a well because Intrepid --

A. Is that the Intrepid No. 2?

Q. It's -- here it is. It's the Intrepid SWD Well No. 1, insufficient info, justification form [sic], approved program, wellbore diagram required; the future change request denied.

A. This was issued.

Q. This is dated 12/26/18. Has it been issued since then? This is the most recent thing I could find on the OCD website.

A. You should dig deeper. Go to the order.

Q. I have the order right here. So the original order was issued November 13th, 2017. I don't want to get hung up on this.

A. Well, it's news to me. And there are other people who are reviewing documents, too, so it's just not me, myself and I. There are at least three other people who are participating in the review of the documents.

Q. I just want to summarize a few things really quickly. You said that you agree with Dr. Zeigler that there is no risk to freshwater resources?

A. Correct.

Q. Would you agree with the EPA statement in the EPA work group, that to date there have been no -- no contamination of underground sources of drinking water from induced seismicity from injection wells?

A. That's correct.

Q. And you earlier note -- stated that there is no impact to correlative rights based on these three applications?

A. Based upon their notice, yes.

Q. And yet you still are recommending denial?

A. I was recommending denial based upon what was originally submitted.

Q. But I thought we were at a new hearing today?

A. Yes, you are.

Q. So you're still recommending denial?

A. I don't make that decision.

Q. So you don't have any input on what the decision should be?

A. That's correct.

Q. Have you discussed what you think the decision

should be with Mr. McMillan?

A. No.

Q. With Mr. Jones?

A. No.

Q. With Mr. Brancard?

A. No.

EXAMINER BRANCARD: I hope not.

(Laughter.)

MS. BENNETT: That's what I'm trying to get at.

Q. (BY MS. BENNETT) How about with the Director? Have you told her what you think the spacing requirement should be?

A. As far as -- she is aware of it. Yes, she is.

Q. And is she aware of the fact that you believe that a 1.5-mile spacing requirement is justified in all cases?

A. She has accepted it as the standard at this point of what we're doing.

Q. So is it fair to say that we're not going to get a fair shake from her?

A. Oh, she'll -- she'll give you a fair shake. Remember that it was only my recommendation.

Q. But you don't get to recommend it, you just said, for now?

A. Oh, no, not now. I'm a witness.

Q. Yeah. You're a witness.

But earlier I thought Mr. Brancard said that you would have input as staff, opposing?

A. I think he used the general staff word.

Q. Okay.

EXAMINER BRANCARD: I'm missing it, but I assume earlier Mr. Goetze testified that he opposed this application.

THE WITNESS: That's correct.

MS. BENNETT: He does.

EXAMINER BRANCARD: Okay. So there you are.

MS. BENNETT: I just want to make sure that Mr. Goetze is not involved in the decision-making process or whether, at the end of the day, these applications should be granted or denied.

I think that's all the questions I have for now. Thank you.

EXAMINER JONES: Shall we go on to the rest of the questions, Mr. Brooks, or do you have any follow-ups you want to --

MR. BROOKS: Well, I had some redirect, but I will wait until after all the attorneys have done their cross. Actually, I prefer to do it after the examiners have an opportunity to examine, but that's been denied before by earlier examiners, so I won't press the point.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I have some questions.

CROSS-EXAMINATION

BY MR. PADILLA:

Q. Mr. Goetze, you testified that you have about 200 applications, correct?

A. That's correct.

Q. What is the time period that you have accumulated the 200 applications?

A. Six months.

Q. How many of those applications have you issued or denied?

A. I couldn't give you a fair -- we're doing about 20 to as many as 30 a quarter, but that would be through my reporting to EPA.

Q. Have you approved any of those applications?

A. Oh, yes.

Q. And what was the criteria for approving those applications?

A. We went to look at first the date of entry and then whether the application had its basic information, and then we would start looking at the proximity with existing wells or wells that have protested or in the queue as far as the application process.

Q. So I take it that all of those applications that you approved were administrative applications?

A. No. They were at hearing also. We have as many as, I believe, ten NGL wells that are at hearing. Blackbuck has put into hearing several wells, Permian Oilfield Partners, as well as individuals such as was mentioned earlier, Longwood. There have been applications made for hearing, and they are pending.

Q. With respect to the Blackbuck Olive Branch well, did you do any site-specific analysis for that well other than proximity to other wells?

A. No, we did not.

Q. I won't go into all the questions Ms. Bennett asked you, but it's fair to say that you didn't do any fault slip analysis or injection rates or injection pressure?

A. No. We do not do -- the only thing we would look at would be the geology and basically the definition of what the injection interval is, something that we could normally do for an application.

Q. Did you do any analysis with respect to the Olive Branch, whether the confining barriers -- basically the Montoya underneath and the upper

permeability barrier, whether those were adequate?

A. We do look at the Devonian, top and bottom, and so yes, we do look at the available information through the Bureau for the -- as well as the Bureau of Economic Geology for what we see as the Simpson and -- God, my brain is giving way. But the Ordovician, we do take a look to see how thick the interval is and then look at what portion of it is Ellenburger.

Q. All of these wells have an interval basically of 1,000 feet, right, more or less?

A. Uh-huh.

Q. Plus or minus?

A. Yeah.

Q. Okay. Now, did you do an analysis as to whether there had been any penetrations beyond the Montoya into the Ellenburger in the area of the Olive Branch well?

A. Typically you're not going to find a penetration in the one-mile area of review, but then you do have adjacent wells that have -- if I am correct, you do have existing wells that are outside of that one-mile AOR.

Q. Now, let me direct your attention to your Exhibit 9-E. I think this is an order.

A. Yes. That's the example of the language we have included in the orders.

Q. How was that adopted? Did you author that?

A. I presented it to management. Yes, I did.

Q. And when you say management, who? Who is management?

A. The Director and Deputy Director -- I mean Director and Deputy Secretary.

Q. And there was no notice of hearing or a hearing to adopt this order?

A. The stipulations were more of a recognition as to if the Division requested this information, that -- the recognition that it had been provided was made part of the order so that the operator would have in his order the criteria by which the Division had reviewed it. And, therefore, at a later date, if there were questions about correlative rights or whether a fault slip analysis had been done, the operator would have in his order evidence that it had been submitted in the exhibit. So it was more of an effort to recognize the additional level of information which would be provided by applicants.

Q. Okay. If I were asked by a client to give them the requirements to meet for saltwater disposal wells in the Devonian, where would I find this, and how would I find this order?

A. We would use the standard C-108, and then we would -- typically when we have a discussion, we would ask if there were additional requirements, considering where we were in the Devonian, as to are there any other additional information requirements that would make this process easier.

Q. Is this order now part of the C-108?

A. It's not an order. It's an information request.

Q. Well --

A. The C-108 is the ability for the reviewer to go and ask for additional information.

Q. Okay. And has the C-108 form been --

A. No. It has not been --

Q. -- changed?

A. -- updated. It still shows the one-half mile.

Q. As I understood your testimony with respect to Exhibit 11, you did not get that Exhibit 11 from the Railroad Commission. You got it from somebody in industry?

A. It is from the advisory group to the Texas Railroad Commission. It is a collaboration of oil and gas operators, as well as the input from the Advisory Committee for the Texas Railroad Commission.

Q. Mr. Goetze, why aren't we here in a rulemaking

hearing?

A. Because we have a 55 percent vacancy rate.

Q. But --

A. I know. I know. But there are extremes -- we should be doing a rulemaking, and it's something the Division needs to do. But it's to the point where to stop and try to make rules and go down the road while you're issuing permits, this is a conundrum we're placed in.

Q. But you haven't -- you haven't issued a moratorium and given a certain time period within which to implement the rules so that everybody can be on the same page?

A. This had been proposed by the legislature, but in light of the fact that this would not support production and, in essence, create waste and more of a problem, the concept of a moratorium is not very viable. You have to move on.

Q. Well, aren't we effectively in a moratorium now because you really aren't issuing orders? Right?

A. Well, we're in a moratorium because we can't write them fast enough.

Q. You did have a technical work group work on this, right?

A. We've had an overall UIC workshop held over a couple of years, and then we had an advisory -- a technical advisory look at rulemaking at the end of 2018.

Q. Since you've been here at the Division, have you -- has the Division implemented changes to the UIC rules?

A. Yes, we have.

Q. How did you go about doing that?

A. Through the process of -- an item was identified as an issue. An initiative was put forth either by industry, by management or by the legislature, and from that, we put together a package for which is presented as the case for Division, which is then brought before Commission.

Q. Did you give notice for those rule changes?

A. We sure did.

Q. Did I hear you say that the Dagger Draw was about 10, 11 miles away?

A. I'm sorry. I mean -- I'm looking at so many things so many times. It is north of the potash zone. It is away from -- but it is an example of what can happen.

Q. And injection in that case was into the Ellenburger, right?

A. The injection did reached the Precambrian.

Q. Okay. What formations are involved in the Raton Basin study that you presented today?

A. Dakota and Shower [phonetic].

Q. Any Devonian in that area?

A. No. We're void of Devonian, but the concept of its inclusion is reflective of, one, that this program is not just about the Delaware Basin, and, two, the injection up there had raised some concerns about the isolation of the injection fluids that have been categorized as being isolated in the Precambrian.

Q. In this case, however, it's got no application at all with regard to the Devonian, right?

A. Just the science. The mechanism and pathway of transfer still represents a point at which, as a regulatory agency, for us to make a decision as the progression of injection goes on. It's not a stagnant situation, that our evaluation of UIC injection wells is a living, breathing thing that we need to be aware of and be willing to provide some sort of pathway in light of observations that are made as a result of us approving orders.

Q. Mr. Goetze, I don't think anybody would disagree with the need for some type of standard for injection wells, and -- but the -- the Raton Basin study is an indication that something may be necessary, but

that doesn't necessarily mean that 1.5 miles is the standard, correct?

A. The Raton Basin, different geology for that.

Q. So it's got to be site-specific, shouldn't it?

A. It has to be -- correct. I will say, as a basin, there would be criteria, and the pathway still remains the same.

Q. What formations are involved in the Socorro study that you --

A. The Socorro only -- the Socorro is a geothermal center, and it has earthquakes greater than 3. It is the director for the state of New Mexico that is part of the WIPP. The state also has a state seismologist, which has an array at Socorro Peak in order to monitor the magma movements. So it is only brought up as a mere fact of coordination.

Q. Different cat entirely?

A. That's true. But we do have a state seismologist finally.

Q. Do you know whether the Olive Branch application contained an analysis of seismology?

A. I do not.

Q. You don't know?

A. I do not go back and review it for this hearing, but I believe that there was a supplemental, but I would have to take a look again. Unfortunately, I'm not as well prepared for you, Mr. Padilla, as Ms. Bennett.

MR. PADILLA: Mr. Examiner, I think in the interest of time, I'll stop here, and I'll develop whatever I have with my witnesses.

EXAMINER JONES: Thank you.

Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Goetze, you've been around the Division long enough to be familiar with the rulemaking procedures before the Commission --

A. Correct.

Q. -- although I personally avoid those proceedings like the plague. There is a certain process. And if I'm misstating it, you let me know. But the OCD identifies a problem, and there is generally a committee formed --

A. Uh-huh.

Q. -- of both regulatory and industry people to go through the issues that are seen by the OCD. And then it has to go to Commission hearing or hearings. A lot of times there are multiple hearings on those rules, and that takes quite a while, doesn't it?

A. Yes, it does.

Q. Now, in the interim, certain cases may arise which require an order-by-order resolution. Is that fair to say?

A. The EPA does cite that in its section of the --

Q. And, of course, you need to do it to comply -- not you. The Division needs to do it to comply with the requirements of the Oil and Gas Act?

A. Well, I would let my attorney speak to that effect --

Q. Right.

A. -- but typically if there are unique situations, we do look at it as case by case.

Q. And even when a rule is adopted, operators -- and I'm talking whether it's SWD operators or oil and gas operators -- need to request an exception to the rule?

A. There are requests for exceptions. Yes.

Q. And, you know, if a rule provides for an administrative application to seek exception to the rule, that's one thing. Otherwise, you generally have to go to hearing -- to the hearing docket?

A. The hearing provides the greater opportunity for examination in presenting information outside of the normal application process.

Q. So even if a rule states X and an operator wants Y, generally you're going to end up at a hearing regardless?

A. The tendency is yes.

Q. That's all I have. Thank you.

EXAMINER JONES: Okay. Let's do a ten-minute break.

(Recess, 2:41 p.m. to 3:05 p.m.)

EXAMINER JONES: Let's go back on the record.

EXAMINER McMILLAN: Scheduling?

EXAMINER JONES: You want to do that now or do you want to do it --

MR. BRUCE: Find out now because earlier we discharged some people. It's probably better now.

EXAMINER JONES: Okay.

MR. BRUCE: Mr. Examiner, you know, it's five after 3:00. Questions from the panel, questions from Mr. Brooks, and then Deana's going to put on a rebuttal witness.

EXAMINER JONES: Oh, yeah. I forgot about that.

MR. BRUCE: So I think we're looking past 4:00. She has to leave shortly thereafter. It's Friday night.

(Laughter.)

MR. BRUCE: I won't say why. But if we're not going to get done tonight, I think Mesquite can be taken under advisement today, but Solaris and Blackbuck -- you know, I don't think Ernie and I going to be all that long, but when all is said and done, it would take a few hours.

MR. BROOKS: Well, in deference to all those, I will forego redirect.

MR. BRUCE: Well, what I'm saying is, it's still going to take a while, and if we're not going to finish up tonight, I'd like the Solaris and Blackbuck witnesses excused so they can get the heck home. And, you know, there are some dates that I think the Division has proposed. We can maybe get together on Monday over those. As I told you, one of those dates is already scheduled for a fight, but I think -- and I can find out probably by Monday whether or not that's going to settle. And maybe that would be a date in a couple weeks to present the Blackbuck and the Solaris cases.

EXAMINER JONES: So two weeks from today?

MR. BRUCE: Yeah.

EXAMINER JONES: Yeah.

MR. PADILLA: That's fine with us. And the reason I'm always sensitive to this is because I was in a case where I had to do my compulsory pooling case in half an hour, and that was a very contested case, and the other parties took most of the day. And by the time I got on, it was half an hour, and so --

EXAMINER JONES: Mr. Catanach had to go home to his kids probably.

MR. PADILLA: That wasn't the -- that wasn't the issue. Whatever it was, I don't want to have that spot in my case just because we're trying to finish by 5:00.

EXAMINER JONES: Yeah.

EXAMINER McMILLAN: Don't we, Phil, have a possible conflict?

THE WITNESS: Are you asking me to my availability?

EXAMINER McMILLAN: Yes.

THE WITNESS: I believe that from -- well, I know from July 5th through July 28th, I am in jury duty, Second District Court in Albuquerque. Yeah, shake your head. So I can see whether -- I've already postponed once, and I don't think I'm going to get a get-out-of-jail card a second time.

MR. BRUCE: Do not pass go; do not collect $200.

EXAMINER JONES: You call in early on

Friday morning, right, and see if you're in or not for the next week?

THE WITNESS: That's correct.

MR. BRUCE: But I think you said that Florene indicated there were some dates, and let's look at those Monday between you guys and Ernie and me.

EXAMINER JONES: Yeah. Okay. I'll have her hold off making the docket then for the 11th.

MR. BRUCE: Yeah. Let's wait until Monday.

EXAMINER JONES: Okay. Let's continue with the questioning of Mr. Goetze.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. My question is: Have you looked at -- have you looked to Dagger Draw?

A. Correct.

Q. Can you describe for me what have you looked at at Dagger Draw?

A. Dagger Draw, I looked at the information that has been compiled with regards to the incident which was identified by both the Bureau and by the scientific community as an incident of induced seismicity within the state of New Mexico.

Q. Have you looked at any of the electrical logs?

A. No, I have not.

Q. Have you looked at any of the regional maps of structure maps in the vicinity of Dagger Draw?
A. Only what is presented through papers.
Q. Okay. Can you -- can you elaborate on that?
A. Well, as part of the paper presented in there, there was structure maps which were not included, but other than that, no there was no effort.
Q. Okay. In your examination of the paper, was there a relationship between -- is there a -- is there faulting through the Ordovician up to the Woodford and through the Woodford?
A. I did not see anything that would suggest that.
Q. What do you mean? You need to elaborate on that.
A. Well, I didn't go into an in-depth review of it, but the suggestion is not necessarily that there was faulting from the basement through the Ordovician into the Devonian, but that communication was established through the injection of fluids below the Devonian-Silurian section.
Q. So what you're saying is faulting was not necessarily a factor in -- in causing the faulting? Is that what you're saying? I'm sorry. In cause of the measurable earthquakes? That's what I should have said.
A. Well, Dr. Lithwen [phonetic], in her

presentation, as well as Dr. Sanford, identified the -- scientists do the high probability that the injection into the area with the Precambrian and the Precambrian stresses are the source of the induced seismicity, and, therefore, that would be faulting that was already present in the subsurface in the Precambrian.

Q. So do you believe there were -- the lithology could have created a pathway for the migration of fluids?

A. Well, I mean, the wells were drilled to the Precambrian, and their completion was documented only partially, and the logs for at least three wells were unavailable. So based upon the general information available, it was more of a physical presence of a wellbore that either would have remained open or was plugged back improperly and still had communication either directly with the Precambrian or through the Ellenburger.

Q. Okay. One of the big factors essentially is this idea of a pressure front. And what do you believe would happen if you put wells close -- closely spaced wells in a pressure front? Could that cause the downward migration of fluids based on the lithologic characteristics of the Lower Ordovician?

A. The concern was raised, and this is part of the reason why this .75 came up, is that as the density of wells increased, we're going to see an increase in reservoir pressure and, with it, the opportunity for migration through the Ordovician, not knowing how continuous or how -- how well a confining member it was considering the spatial density of the wells used to map and correlate. So their use of this template to select and deny raised out of an initial concern for pressures rising in the reservoir and potential migration.

Q. I think you said something in your testimony that you either -- that there's very few cores available in the Lower Ordovician. Did you -- correct?

A. Yes.

Q. Did you ever have a chance to look at those cores or look at a -- an examination of --

A. No.

Q. -- work by experts who really get a core analysis for the lithology?

A. No. The only cores I looked at for Devonian, but I did not look at the available cores for the Ordovician section.

Q. And you didn't look at -- you didn't have the opportunity to look at some of the core descriptions by researchers?

A. Well, there are some references. But again, they are based upon the density that is quite sparse, and you may be looking at quite some distances between what was provided in their descriptions. But they are limited in themselves.

Q. And did they say that they were -- were they -- in those descriptions, were they barriers or baffles?

A. I would state that a majority of them did identify a permeability and change in lithology, which would be a barrier -- confining barrier.

Q. Okay. So it's your -- do you believe -- and I believe Mesquite said this, that faulting is a major factor in -- or are there other factors involved?

A. Well, their modeling includes review for faults of concern, as well as not only faults through the injection and below but below in the Precambrian, as that is part of the fault slip potential assessment. There are some faults that are present, and they were presented but at some distance away.

EXAMINER McMILLAN: Go ahead.

EXAMINER JONES: Mr. Brancard?

EXAMINER BRANCARD: Oh, sure.

CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. Okay. Let me just figure out what the Division's staff position is here. We have five

applications, and if I read from your Exhibit 1, you are requesting that the director deny all five --

A. Correct.

Q. -- based on this idea of maintaining a distance of 1.5 miles between injection sources? That's what I'm reading from this here.

A. Correct.

Q. And so the chart shows that for each of these wells, there are two sources either existing or proposed that are within 1.5 miles?

A. That's correct.

Q. So in other words, if Mesquite dropped one of the Laguna Salada wells, the other Laguna Salada well would still have a problem?

A. Using this criteria, yes. But if they were to relocate it, no.

Q. Okay. And so with the other two Applicants, part of their problem is that they're interfering with each other, is that correct, the Predator and Olive Branch?

A. Yes, both of them being within .55 miles of each other. That represents an issue.

Q. If one of them -- if one of them gets dropped, but they each also still have another well within 1.5 miles?

A. But we have -- and we have worked with operators. The 1.5 is what we'd like, but we'll offer the opportunity, again through hearing, to convince us that it's -- that that distance doesn't necessarily have to stand with sufficient information presented that there would not be issues.

Q. Right.

So Mesquite has proposed to go with what they claim was sort of the earlier policy, which was a one-mile, which they would be -- under this, they would be okay with a one-mile but Blackbuck and Solaris would not?

A. Well, the one-mile, again, refers to only area of review and --

Q. Well, I'm talking a one-mile distance from the injection sources.

A. We really haven't. It's not until we've gotten into this large-volume injection that we were looking at this separation.

Q. Right.

So that's -- that's a point that I think we haven't really talked about here, is that the parties are talking about this sort of came out of nowhere, but isn't this somehow related to larger-volume disposal and larger tubing?

A. The Mesquite case brought forward the concept that the industry was heading towards a larger injection volume and, with it, because of the depth that we were looking at in the Devonian, the cost effectiveness of having a much larger tubing, much larger injection volume became pretty much a model that industry approached and grabbed on to. So with that, we started to see applications scaling up to as much as 100,000 barrels a day.

Q. Right.

So it's that change, that shift in the tubing size and, therefore, the volume of injection that inspired this move to a larger distance between wells?

A. Well, yes, to consider the distance between wells, to think of something we could do.

Q. Okay. So before you didn't even consider that?

A. It used to be that we would just three-quarter -- I mean, we had -- 2-7/8 and 3-1/2 were the big ones, and rarely did we see anything in 4-1/2.

Q. So prior to the larger volume, you focused simply on the injection rate --

A. Correct.

Q. -- as your control?

Okay. Now, a lot has been made about the lack of a site-specific analysis and that you're sort of

arbitrarily pushing this 1.5-mile on all these wells, but judging from these maps you've given us here, it appears that there are a number of wells here -- and I think you've already described it -- that have smaller radius --

A. Correct.

Q. -- radii.

And that's based on?

A. The well construction and the inability to scale up to a larger tubing size; therefore, physically being limited by their original design.

Q. So while you are talking about an across-the-board 1.5, in reality, you're really talking about the 1.5 for wells that have the larger tubing size?

A. Well, for applications that are large capacity, yes.

Q. Okay. And so to flip to the last exhibit, 9, the Scanlon paper, look at page 175 there. It talks about linkages between produced water and seismicity, page 175, the little numbers at the bottom right-hand corner.

A. Thank you.

Q. They say, under the second column in the top there, "Oklahoma, Potential controls on produced water

management seismicity include," and they just list three options. Okay? Injection rate, you've always done, correct?

A. It is done via the .2, the pressure injection, but for --

Q. Right.

There's no -- there's no -- there is nothing in Rule 26 that requires that; is that correct?

A. That's correct.

Q. There's no number in Rule 26. That's always been there, throughout all the orders issued in the past?

A. .2 psi?

Q. Yeah.

A. .2 psi is what we submitted in our primacy demonstration, and it's approved by the EPA.

Q. Right.

But it's not in the state regulations?

A. No, it's not.

Q. And so the third one we've just been discussing here, which is this proximity injection to the basement, this is where -- you enforce this through not allowing injection into the Ellenburger, correct?

A. Correct.

Q. Again, there's nothing in the rules about that.

It's simply a policy. But if Mesquite came in next week with six applications into the Ellenburger, you would propose to deny them, wouldn't you?

A. Yes, I would.

Q. Okay. Would you be back in front of us here trying to justify that?

A. That would be up to Mesquite.

Q. So the middle one, though, it says "regional cumulative injection volume." Is that what we're really talking about here? I mean, we're talking about these volumes that are now being pushed into the water -- into this injection level, and you're trying to get control over that?

A. This is where we're heading as far as what we're trying to look at as a management tool. Yes.

Q. Okay. And so if you go down two paragraphs, it says, "In (2), we find the cumulative injection volumes for SWD wells in Oklahoma to be statistically associated with earthquakes." So in Oklahoma, they have an association between that volume and earthquakes, right, and that's what they've focused on? But they haven't focused on it by spacing; they've focused on it by --

A. Managing injection rates, as well as individual wells.

Q. Right.

So -- and that seems to be in the Texas data, too, that they were imposing conditions where they were capping the injection volume barrels per day, right?

A. That's correct.

Q. And we don't do that, do we?

A. We do not.

Q. Nor do we put a cap on how long your permit is for, right?

A. The assumption is that once you've reached the formation parting pressure, that the well is no longer and the permit is invalid, since you will now be exceeding what the UIC regs say.

Q. But if they don't, they could --

A. Go on for a long time.

Q. -- go on for a long time, right?

So could the Director look at putting caps on injection volume barrels per day?

A. As part of the legal conditions, I would not know, but it's something that could be recommended to her. In certain cases, we've actually had applicants request that, and we have included it in the order that was signed.

Q. Okay. I'm just trying to figure out what's acceptable here and what other -- because it seems

clear, from what Mr. Brooks has said about the Oil and Gas Act, what's in the EPA document, that the ability to deal with this on a site-specific basis and EPA specifically says, under UIC, the State has the ability to put conditions on a permit, right? That was in the first document?

A. That's correct.

Q. So I'm just sort of wondering what conditions are acceptable then to the parties.

So I want you to explain to me something that's in this article relating to earthquake sequence in the Raton Basin here, 6-F. Well, something caught my attention on page 12 of this article.

A. Yes.

Q. Yes. So the first sentence there, "Even in an underpressured, extensional system like the Raton Basin, where fluids can typically be injected with no wellhead pressure, earthquakes can still be induced."

A. Yes.

Q. So if one of your controls and your primary control is your pressure rate, how does that relate to that statement?

A. Well, it would state that the use of the .2 psi per foot would not necessarily provide us any type of protection, as well as management tool if the reservoir were able to accept fluids on a vacuum, which essentially is a hydrostatic pressure. So it may be that the opportunity, regardless of what pressure we put on it, will not necessarily guarantee any type of control and preventive management for induced seismicity.

Q. Okay. So the Department has traditionally for years hung its hat on this injection rate control, but that may not be adequate?

A. That may be very true, especially with discussions with Dr. Rubinstein.

Q. So really it would be incumbent on the Director then to consider what other controls might be helpful in avoiding induced seismicity?

A. It's a task that's been handed to us in the sense to find something that works.

Q. Right.

So while, I mean, counsel has made the point about all this wonderful stuff that has come out of Oklahoma and the transparency of Oklahoma, the reality is all that wonderful stuff that came out of Oklahoma came out after Oklahoma had over 900 3.0 or higher earthquakes in one year?

A. That's correct.

Q. That's what you're trying to avoid?

A. We're trying. Yes.

Q. Okay. Thank you.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Okay. The Mesquite testimony from their witnesses, what would you have -- what do you like about it, and what did you not like about it?

A. To say that I have not heard that testimony before, they have presented it; the experts have been called to present testimony before the Commission -- or before the Division and are very good at what they do. I mean, all -- given the efforts by each of the expert witnesses does provide an evaluation which addresses many of the concerns. The fault slip model, as performed by Mr. Reynolds, is part of an understanding which exceeds the Division's ability to do anything by far. The tendency is then we get back to what are the assumptions and what the information is used to make those determinations.

So questions have been raised as to where we are in the section and how thick and how well-defined the confining layer and, looking at the modeling, the assurance that what we're getting is the best available. Even if there is concern, would there be a higher standard that would be required? But the Division at this time does not have that expertise.

Q. Okay. Mr. Reynolds' testimony about the faults seemed to focus on the faults being the danger point and so the modeling showing that if you keep all the wells at least one mile away from the faults -- the modeling that was presented, I think, afterwards with the reservoir engineer showed that maybe that would be a good path to go by.

A. Well, this raises the other question which has been presented by the senior petroleum geologist, Mr. Ron Broadhead, of the New Mexico Bureau of Geology & Mineral Resources with regards to the overall general characteristics of the Devonian and Silurian. Yes, as a basinwide receiver of injection fluids, it's more preferable than anything we have available. But as has been demonstrated by the some of the operators, certain locations certainly are better reservoir rock, while others have limitations that were not identified until the well was drilled. So the modeling is good. The tendency is, down the road, you're going to have to take a look to see how that model fits into the real world.

Q. Okay. But it seems like it wasn't a very useful exercise to focus in on the faults and assume all the faults are nonsealing faults that are communicated to the basement rock, even though some of them may be

sealing faults, correct?

A. Well, that would be an interpretation based upon available information.

Q. Okay. Well, pressure data on either side of the faults might tell you something about that.

But the other side of the coin is -- and I had this question in my mind when they were presenting it. If there is an issue with a higher rate -- concentrated rate of injection even a long ways away from the faults, how could that affect the basement rocks? Do you know enough about the Simpson as a sealing -- bottom-sealing rock, that it would prevent it? I mean --

A. We're going on -- well, the New Mexico Tech library [sic] has six cores for Simpson. And so we are making the assessment based upon folks who have mapped it, of course, from different directions, whether it's the Bureau of Economic Geology and/or the Bureau of Geology in Socorro. So -- and we have generally accepted the ability of it in certain locations, because of the thickness, that its permeability and porosity barrier will be such that it will be able to handle it, but that is based upon regional, not site-specific.

Q. Okay. So let's say conditions for approval of wells that are spaced closer than a certain even

arbitrary setback, what would you propose?

A. I don't know. We are still going through that, how close can we get and what would the information be needed.

Q. Yeah.

A. As a result of our work study groups, the question was raised: I have an open hole with a large-capacity well. How do I do a step-rate test on a well that will that take 30,000 barrels per day? How would you -- a lot of the operators have expressed concern with placing tools downhole in the open hole to do injectivity studies or step-rate tests, and, with that, how would you evaluate the reservoir? What questions do you ask up front?

The acid-gas wells, we tend to have a very much over-the-top evaluation for those, which include step-rate tests and fall-off tests, as well running extensive log suites. And in light of that, the availability of information for those wells is quite cumulative. And, of course, with those wells, we actually put in requirements for downhole pressure temperature assessments and collecting of data.

On the other side of the scale, we've had concerns over how -- as an alternative to a step-rate test, what would be the best bottom-hole measurements, sampling on a quarterly basis for pressures, a variety of information that is out there, and how would you include that in an order and know that down the road that's going to be beneficial for you to make an assessment.

So we are relying on industry, and this is the way we do business, is to come up with some type of protocol that can be done with a low potential for losing equipment that is nonintrusive as much as it can be and at the same time gives us something that we can look at the reservoir with.

Q. It seems to me like the cumulative volume going -- buildup in that Devonian -- the term "Devonian" injectivity zone is -- is going to go up over time. No matter what anybody does here, it's going to go up unless you say no injection in the Devonian. So it's going to go up. So then you've got the other issue of if a concentrated rate in a given area is an issue, where you don't have time for it to dissipate, is that -- through the literature, has that been identified as an issue?

A. Well, for the Arkansas experience, they actually have no injection zones in the Arbuckle as a result of concerns and at least a level of confidence that continued injection will result in their episodes of seismicity that they've had. So, again, back to the concept of management, yeah, there are places that we're going to probably see a cumulative effect, and they'll have to be evaluated on the merits after the injection has occurred.

Q. Yeah. Okay.

There seems to be a lot of things that can be done to not only gather information as the well is drilled and completed but also in the continued operation of the well, you know, like Hall plots or pressure transient analysis or, you know, as you complete the well, a little bit of sidewall coring, things like that. Have you seen operators do that and let you know about that kind of stuff?

A. The only folks who have brought forward such information have tended to be the larger operators like XTO and Chevron. As part of their protocols for assessing the well in their operations, they do this type of data accumulation. But other than that, no, it is not. The most we ever get is a log suite and then pressure and volume monthly.

Q. Even people talking to you about what they've done to their well that they haven't submitted to you, they haven't talked about enhanced operation of the well? I mean, obviously, you're requiring SCADA systems

now, but --

A. There are midstream operators who have come forth with the ability to include SCADA systems and have requested that we include it, as well as, in the case of NGL, lay out array systems and have their own in-house seismic recordings.

Q. Okay. One of the -- one of the black boxes I see is the actual Simpson, whether it is a -- what data is available for stress in the Simpson versus stress from the Devonian zone? And that's something that I wasn't totally -- I don't think the data is out there yet, or if it's out there, it wasn't presented the other day, about not quite a month ago. So have you heard anything about -- is the Simpson variable as to the thickness in this area, or is it just a general thick shale, or what is it?

A. As you come up the basin, its thickness will vary. Certainly as you come up towards the shelf, it thins out, as does the Woodford, as well as the Devonian section. So there is regional play into it.

As far as the varieties, in certain areas, the Simpson has been productive on the platform, but at the same time, it's not truly representative of what's in the basin. So --

Q. Okay.

A. -- that would be information that would be available. To correlate to the basin would be a different --

Q. Okay. So the Simpson has been oil productive up on the platform?

A. It has. It has. They have had pools.

Q. Okay.

A. Not very big. Just one or two wells.

Q. So it's possible it could be gas productive down in the basin?

A. Well, you're a petroleum engineer. I'll let you decide that.

Q. Well, I can't be a seismologist either.

As far as notice goes, you said you're doing a one-mile area of review and a one-mile notice?

A. Correct.

Q. Okay. Are you just doing the standard notice that is required in the rules, or are you requiring notice -- if this is going to cause induced seismicity or if it's a possibility, those people living on the surface maybe should be required notice, too, or the surface owners, right?

A. Well, that would be a water-quality standard as far as notice of surface in that radius, but we are still just doing it based upon the affected persons as defined in the New Mexico Administrative Code.

Q. Okay. This ten kilometers, is that a radius -- I forgot what Mr. Reynolds said, whether it was a square or a circle.

MR. REYNOLDS: (Indicating.)

EXAMINER JONES: It's a circle. Okay.

Q. (BY EXAMINER JONES) Okay. 122 square miles, right? And say again what they were using that for. They were looking at --

A. They -- the process in Texas is to look for anything greater than a 2.0 event, and then with that, the level of information requirements increases. So it is a -- a decision box, you may say. If you have nothing showing up, even the minimum requirements should be, it's fine. But doing the 2.0 and above gives certainly a greater review of what is on record.

Q. Okay. And as far as why a rulemaking hasn't started yet, couldn't that have been initiated by the operators also or NMOGA?

A. Well, NMOGA has been in discussion with us and has presented to us. So --

Q. So they're just talking, but they're not doing anything?

A. Well, they have asked, but at this point, no, there is nothing gone forward.

Q. The faults that Mr. Reynolds talked about -- I'd have to go back and look, but I thought he compared the faults in the Oklahoma orogeny area that might have been stack slip-type faults and these faults in the -- in this area being normal type faults with a 30-degree angle. So those are a little bit less likely to be -- have induced slip on them; isn't that correct?

A. The Lund Snee-Zoback paper does present a very accurate picture as to what faults have the potential for -- at least in the Permian Basin. But as stated, it's based upon what's available as far as information that's out there already.

Q. Okay. Thank you.

EXAMINER JONES: Any --

MS. BENNETT: Well, I don't know if this is appropriate, but I did have a few follow-up questions based on questions the examiners asked. I don't know if that's allowable.

EXAMINER BRANCARD: Well, I think it's Mr. Brooks' turn.

MS. BENNETT: Okay. Thanks.

MR. BROOKS: I indicated earlier that out of deference to Mr. Padilla and Mr. Bruce, they need to get their witnesses out -- or at least my understanding was we were going to put Mr. Padilla's witnesses on today and Mr. Bruce's on another date; is that correct?

MR. PADILLA: No. No. We're not going to put on a case today.

MR. BROOKS: Okay. I'll go ahead and ask a few questions that I have.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. Now, the notice requirement refers to area of review and describes specifically the relationship between the area of review and the parties to be noticed, correct?

A. Correct.

Q. And it uses the term "area of review"?

A. It does.

Q. And the term "area of review" is a term of art in the UIC rules?

A. That is correct.

Q. So the fact that we may urge a larger setback area does not ipso facto require additional notice?

A. No, it does not.

Q. Okay. And notice was given, and there is no contest, I believe, that notice was given in this case to everybody to whom notice is required by OCD rules?

A. That's correct.

Q. Okay. Now, the point was made on

cross-examination that a lot of other formations other than the Devonian are above the Ellenburger. In fact, most things are above the Ellenburger, correct?

A. Yes.

Q. If the Ellenburger is present?

A. That's correct.

Q. Now, is the question here, though, not rather the proximity -- the distance between the base of the injection interval and the Ellenburger is relatively short compared to shallower formations --

A. It is --

Q. -- than the Devonian?

A. It could be equal in separation as to the Devonian-Silurian section depending upon where you are in the basin, or it can be, I mean, reduced down to 300, maybe 500 feet. So it depends on where you are in the basin, and that separation will be dependent upon what information is available.

Q. Well, several of the articles in the exhibit refer to were the fact that for a long time most injection has occurred above the oil-producing zones, which put them fairly distant from the basin, right?

A. That is correct.

Q. And they've attributed some significance to that fact?

A. Yes.

Q. And here there is not a lot of separation between the injection formation and are the Ellenburger in terms of total feet of rock between the two?

A. Again, it would be a thickness assessed by the best-available information, whether it is from core and/or seismic or well drill logs.

Q. So you don't know exactly whether it is consistently on the basin?

A. The level of spatial information is not as great as other formations.

Q. You've conceded that you know of no -- or have not identified any freshwater sources that would be endangered --

A. Correct.

Q. -- by the applications?

However, they did induce seismicity that could change; could it not?

A. The potential is there that the cement for the well could be impacted.

Q. Now, there was some talk about the word "moratorium." A moratorium is a temporary rule, in effect, if I'm using that term right.

A. Yes.

Q. How long would any temporary rule be affected

that the Division might be entitled to make?

A. Well, based upon my experience with the Roswell Artesian Basin, it would only be good for 15 days.

Q. I believe that is correct.

Thank you.

MR. BROOKS: I'm going to pass the witness.

MS. BENNETT: May I ask a few follow-up questions then?

EXAMINER JONES: Go ahead.

MS. BENNETT: Okay. Thank you.

RECROSS EXAMINATION

BY MS. BENNETT:

Q. These are questions in response to Mr. Brancard's questions to you. He asked you whether OCD could impose volume limitations on wells, and you hesitated and said that you weren't sure if OCD could do that as a permit condition.

EXAMINER JONES: Wait. You mean rate.

MS. BENNETT: Rate, yeah. Well, I guess I mean volume.

EXAMINER JONES: Volume is like filling up a container --

MS. BENNETT: Uh-huh.

EXAMINER JONES: -- but rate is volume per unit times. So --

MS. BENNETT: Okay. Let's go with rate (laughter).

EXAMINER JONES: Yeah.

Q. (BY MS. BENNETT) So -- but my understanding was that your position today, the OCD's position, is that OCD has the authority to condition permits or to impose requirements to protect the environment. Is that your position?

A. Yes.

MR. BROOKS: I would object to that question because it asks the witness to come to a given opinion on a question of law.

Q. (BY MS. BENNETT) Let me just ask you this then: Turning back to the EPA report, the EPA report identified a number of operational approaches that it recommended or it suggested to regulators -- administrators, on page 34.

A. Uh-huh.

Q. And the fourth bullet down says, "Modify injection well permit operational parameters as needed to minimize or manage seismicity issues," and the very first one is reduce injection rates.

A. Uh-huh.

Q. And that's the same bulleted list that you've chosen to select the 1.5-mile spacing requirement from;

is that right?

A. That bullet?

Q. That same list, the very next -- two bullets down, "separate multiple injection wells by...."

A. That is one we looked at. Yes.

Q. So even under EPA's own workbook, you could -- or this guidance document, OCD does have the authority to reduce rates?

A. Well, three times I've been in hearing over it, no. I've lost.

Q. So how does OCD have the authority to impose spacing requirements but not injection rates?

A. Because we have been defined by the .2 psi per foot, which then makes the characteristics of the reservoir critical. This is why we had fracturing in the formation of the Delaware Mountain Group resulting in injection out of interval, in violation of the UIC.

Q. When Mr. Brancard asked you about the proximity to the -- of the Solaris and Blackbuck wells, I think you mentioned that even if one of those went away, in response to Mr. Brancard's question, even though they're closer than 1.5 miles to other wells, OCD could still approve those. Was that your testimony?

A. We would take another look at it, but it would be such that one of the wells was not going to be there.

Yes.

Q. But I thought you testified, too, that if one of the wells wasn't going to be there, you could still approve the remaining well even though it's closer than 1.5 miles to an existing well.

A. We have, based on the history of our program, approved things closer than 1.5, and we've done it with -- both in the Matador cases at hearing, as well as with consideration given to the fact that they were preexisting wells. The order from the Commission warded [sic] -- the ability to increase the injection of wells in close proximity was approved, but at the time, we didn't have that understanding as to how close things were.

Q. But even today you're saying that you would allow a company to come back in and get a well closer than 1.5 miles to another well if the evidence at the hearing was such that you felt comfortable approving that?

A. If it was such they answered some of the questions about induced seismicity, because we do have many different types of operators, and we do have different levels of what induced-seismicity modeling has done. And this is something that has been identified to us by the scientific community, that in many respects, for not having a criteria of what an induced-seismicity assessment is, that we have opened the door to another issue.

Q. Earlier, though, you testified that Mesquite's witnesses did a thorough job and that they try to address induced seismicity and that they've testified before Division a number of times. Is there anything in their --

A. Each of those is handled by a case-by-case basis.

Q. Exactly.

A. Yes. I know.

Q. Mr. Brancard asked you about notice and he said that the Oklahoma approach was based on, you know, three years or multiple evidence of earthquakes and isn't it better to be proactive in New Mexico. And wouldn't New Mexico and New Mexico citizens and New Mexico regulated entities benefit from that transparency at outset versus the Division coming up with rules and screening tools that aren't even identified to the regulated entities so they can partner with the Division in preventing the type of earthquakes that happened in Oklahoma?

A. We already do that through our AGI well program.

Q. But I guess my point is there is nothing that's keeping the Division from providing notice of a 1.5-mile spacing requirement?

A. No.

Q. Okay. And, in fact, that would actually help the regulated -- the operators if they knew?

A. So would a staff.

Q. Outside of the scope of that, but I'm happy to help with that, too, if I can.

A moment ago, in response to Mr. Jones' questions about what you know and don't know, you were saying that there are so many variables that you have to take into account, like when are you going to do a bottom-hole test, what's the step rate, how do you even do a step-rate test for 30,000-barrels-a-day injection well, isn't that the exact reason, all those variables, that a rulemaking would be appropriate here?

A. It would be rulemaking based upon what was the best recommendations. But at this time, we still don't have a clear path as to those recommendations. That was the reason for the meetings in 2018, is to define -- define at least parameters that need to be addressed and the methodology of doing it and what we accepted as an industry standard or would be applicable to our concerns. That's still being discussed.

Q. Mr. Brooks asked you a question about this level of separation. He said, So are you concerned that there is not a lot of separation here. And you said that varies in the basin -- throughout the basin, and it's narrower at the shelf and deeper and thicker someplace else. Do you know what the level of separation is for these wells?

A. It is -- no, not at this point. My head is kind of ended out. But I'm sure you'll remind me. But yes. There is, based upon the cores available, what was estimated to be a large section.

Q. So any concerns about a lot of separation doesn't really apply to these three wells, does it?

A. Only if the well is properly installed.

Q. And you have -- through the OCD regulation, there are controls about how wells are to be installed and maintained?

A. Yes, we do.

Q. Thank you.

You said that there is the potential for the cement to be impacted if there is a seismic event?

A. There is potential.

Q. Does that exist for every well or just Mesquite's wells?

A. It exists for every well.

Q. Does it exist for wells that are two miles apart from each other?

A. It exists for everybody.

Q. So that is irrespective of their distance from each other?

A. Well, it is a finding of the EPA. It's one of the things they identified, that if you did have induced seismicity -- especially for older wells, we've got API cements that are not to standard.

Q. Are these wells older wells with APIs that are not to standard?

A. These are not the wells that would be impacted, but they may be impacted if not properly cemented. I already have four wells that are not properly cemented as a result of improper circulation through the liner, which means that the zone of the H_2S sources, primarily Pennsylvanian, are exposed to casing. And so we have had new issues with regards to improper cement circulation, as well not having proper information provided to our district. So --

Q. Are those Mesquite wells?

A. Pardon me?

Q. Are those Mesquite wells?

A. Not at this time, no.

Q. Those are all the follow-up questions I have.

Thank you.

EXAMINER JONES: Okay. Is that your case, Mr. Brooks?

MR. BROOKS: I believe so, Mr. Jones. I'm not waiving -- since the other parties have not presented their rebuttal yet, I'm not waiving any right that we have. Although I realize we normally don't have to present, but that can be requested, and I'm not waiving anything on that. But that's my case. That's the Division's case.

EXAMINER JONES: The Division's case.

You want to put on a rebuttal witness?

MS. BENNETT: Yes, just a very quick rebuttal witness.

EXAMINER JONES: Okay.

MS. BENNETT: Thank you.

At this time I'd like to call Mr. Todd Reynolds.

EXAMINER JONES: Let the record reflect that he's been sworn already approximately a month ago.

(Laughter.)

EXAMINER JONES: Hopefully he hasn't forgotten.

TODD REYNOLDS,

after having been previously sworn under oath, was re-called, questioned and testified as follows:

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Mr. Reynolds, thank you for coming back today. I just have a few questions for you.

The last time you were here, we talked about an exhibit that you had prepared that we didn't have time to present because we were getting close to the end of the day; is that right?

A. That's correct.

Q. And is that exhibit essentially what I've handed out today, Mesquite Rebuttal Exhibit 1?

A. Yes, it is.

Q. Is this what you described to the examiners last time as a hypothetical study of a 1.5-mile well between a critically oriented fault versus 1.5-mile with setback limits near the fault?

A. Yes. That's what it is.

Q. And so your modeling essentially takes the same distance from between wells but then runs a different model for proximity to a fault versus proximity or distance from a fault?

A. That's correct. And what the exhibit will show is that simply creating a checkerboard pattern of wells 1.5 miles apart will do nothing to mitigate the seismicity risk if there is faulting in the area because some of those wells are going to be too close to the fault. And if we're going to screen wells that should or shouldn't be drilled, we should be doing a geologic screening rather than a geographic screening to try to make an attempt to identify faults in the area and really scrutinize anything that gets permitted too near those faults.

Q. Now, let's look at your FSP analysis really quickly, because earlier today we heard that there isn't a lot of data around in this area. And I understand this is a hypothetical fault slip probability analysis, but for these particular cases, Baker and Laguna Salada, were you able to find readily available data sources?

A. Yes. As far as -- you know, we have the Snee-Zoback paper to get an estimate of the direction of max horizontal stress. That's one of the parameters.

We've used, you know, the thicknesses from wells that have been drilled out here to identify the interval. And in addition to that, we've gone very conservative in saying that only -- we're only going to use half of that interval as the modeled injection interval instead of the entire interval.

And then there are a number of wells that are drilled to the top of the Barnett and the

Mississippian where you can take those wells and project down to the Devonian or down to the Ellenburger based on thicknesses that you see in the wells that went deep enough to see those other intervals. You can isopach each -- each interval and just add it to -- to those logs that got to the Barnett or got to the Mississippian.

And in this specific area, there's -- I think I have over 50 well points in my area of review to -- to derive a structure map on the top of the Devonian, and it's not unlike what Mesquite would do to estimate the formation tops when they went out there to drill the well. They're going to take the information that they have to construct the best structure map that they can. And if it identifies faulting, typically what I have seen is the problematic faults in all of these areas do cut up through the sedimentary section to some extent. And so they are identifiable. They're not just these varied basement faults that aren't seen up in the section somehow.

And that's what we've done, and we'll show that through another exhibit. But there is -- there is a lot of information out there, but you have to look at it.

Q. Uh-huh.

And so for the Baker and Laguna Salada wells, you actually did a site-specific fault slip probability analysis?

A. Yes, I did, and that was presented last time. And then for this -- excuse me. For this hypothetical, we just put those same parameters into the hypothetical model, thickness, stress values, all of that, to just -- to run the same model of a hypothetical fault that would be located in this same general environment.

Q. Can you run us through the fault slip probability analysis that you have here -- the hypothetical fault slip probability analysis?

A. Sure. ST-1 would be the first page of the analysis, and we've noted a fault that's oriented somewhat northeast to southwest, which would be the most critical angle that the fault could be from an azimuth standpoint.

MR. BROOKS: Which tab are you looking at?

THE WITNESS: ST-1.

MS. BENNETT: Right behind Tab 1.

THE WITNESS: On Exhibit 1, near the page number. Spacing Test 1 is what the page number is.

So the FSP software calculates that a fault of critical orientation at this depth would have a pressure to slip of 1,750 pounds, roughly. And why do you see this repeated over and over and over? It's because we've treated this fault as multiple segments. The FSP calculates the pressure at the center of a segment. And so just to draw one big, long segment here would only calculate the pressure right at that center point, so we've segmented the fault up into multiple segments because we're going to put multiple wells in here that we're going to look at.

So 1,750 is the pressure that's going to cause the fault to slip if it's oriented in an optimal direction and has a near-vertical dip, which the faults out here do, of, you know, 80 degrees, 85 degrees. They're near vertical. And those parameters were all put into the model.

The second page, ST-2, is the wells that were put into the model. Basically, it's just a spacing of -- I think there are 30 wells in here, all a mile and a half apart, all injecting at 30,000 barrels a day, and you see the fault running through the cluster of wells there, the diagonal northeast-southwest line.

If we go to page ST-3, now we're running the model forward based on those well spacings and those injection parameters, and we start to see the pressure that's building along the fault. Those values you see are 692 pounds, 700-something pounds. They're in the middle, and as you get out to the end, the pressure is less. But that's at year 2025. Okay?

Then we look at 2035, and now the pressure is approaching the pressure that it takes to allow fault slip, which is 1,750 pounds. You can see in the center section there that we're up around 1,500 pounds now, and that represents a 30 percent chance of fault slip, based on the model, which is shown in the column. On the far left-hand side, you see the color coding of the faults. Some of them are starting to turn yellow from green. So that's showing a higher percentage chance of fault slip along that fault segment.

If we go to ST-5 -- page ST-5, now we're out at 2045. And so we have all these wells drilled a mile and a half apart, but yet we're beyond the pressure that would cause fault slip now. We're at 1,900 pounds. We're 1,700 pounds at several segments along the fault. And so you would expect fault slip at this point or prior to this, actually.

Okay. So now we go to page ST-6. And what we've done here is we've decimated the wells that were within a mile and a half of the fault. We've taken those out of the model and said, you know, Those wells never should have been drilled in the first place based on proximity to the fault. We still have the wells a mile and a half apart, and, you know, that might be something to be considered in an area where you know there is a fault.

In an area where there is no evidence of faulting, I'm of the opinion that a mile is appropriate for distance between wells.

But here you have an instance where you have a fault, and so you're not only spacing the wells a mile and a half off the fault, you're spacing the wells a mile and a half from each other also.

So we run the model out now, and at 2025, we're starting to see about 300 pounds along the fault, same injection profile as before. All these wells are injecting at 40,000 barrels a day.

ST-7 is at the 2035 year range. And so we're still -- all the faults are still in the green, showing zero percent probability of fault slip. You're keeping the pressures down below the pressure that is necessary to initiate fault slip.

And even all the way out to 2045 -- it is a given -- pressure is going to increase as the time increases and the volume increases, but at this stage, we're still 600 pounds below the pressure that is necessary to initiate fault slip. And all of the fault segments are still showing a very low probability of fault slip. I think fault six is showing 3 percent of the fault slip.

So in my experience, in looking at all these case studies that were listed, there is a problematic fault on every one of them. In the induced-seismicity world, they've identified a fault. Oftentimes, it's -- in most instances, it's less than a mile and a half, two miles from the well. In many instances, it's intercepted by the wellbore. In other words, the well cut the fault. And in a few instances, it's a situation where they blew out the bottom of the zone and blasted through the confining layer.

That's not the case. So all this discussion of confining layer, it's -- it's good safeguard. It's good insurance. But in all of these cases, that was not the reason of induced seismicity. It was -- it was -- the conduit was the fault down through -- you know, the fault cut through the confining layer and provided the pathway down into the basement or the -- or the depth of seismicity. And generally it's not every fault. It's the ones that are oriented parallel to the stress field which tend to be more open and conductive because of their orientation.

And there has been a tremendous amount of discussion today about the Simpson and whether or not it's an appropriate confining interval. It would seem that that's been decided a long time ago when injection into the Devonian was allowed. So it's really kind of an irrelevant discussion on this idea of what the proper spacing this way (demonstrating) should be. That's more of a vertical consideration, which is similar to -- in Texas, we have vertical consideration of distance from the basement that injection is allowed, and -- but that's a different subject than why these permits were denied.

Q. (BY MS. BENNETT) You had a few other documents that you included with your exhibit. Are those contour maps and logs that you used to -- for data points?

A. Yes. Under Tab 2 -- and for each of these following exhibits, which are maps and cross sections, I have oversized sections that I can leave with staff and provide to the other side so that we don't wreck our eyesight any further than it already is. So we can pull those out and look at them if needed, but we'll talk from these for now.

Q. And just remind me. The first one which is -- that says "structure map showing top of Devonian and cross-section lines" in the legend here, is that the first one we're looking at?

A. Yes. What you see here is the 100-square-mile area of review around the two wells, which is a radius of 5.64 miles or 9.08 kilometers, is what it works out to. So we've looked far and beyond what is typically asked of us in Texas, and we've mapped the structure. We've taken the data points that go to the Devonian and all the other data points in this area that reach the Barnett and/or Mississippian, and we used those points based on the thicknesses to provide a projected top to the Devonian. So what you see is the structural expression of that on this contour map.

And what we'll see in some other exhibits is the faults -- this is at the stage when faults kind of identify themselves or present themselves in the data. If you see a major change in the contour interval or something like that, it's suggesting there could be a fault there.

Q. Do you see anything like that on this contour map?

A. No, I don't. And we'll look at the cross sections to see how they represent the structure also. And I know there was a comment last time about the lines of cross sections being on the same map as the geology. I need that to be able to look at the cross section and look at the structure map and say, what should we be seeing here? Should we be seeing a gradual dip, or should we see a step up? And you should see that reflected on the cross sections also. So I would keep that map out and handy as we look at cross sections A and B, A, A prime and B, B prime.

A, A prime is basically a dip cross section running from northwest to southeast. And on this cross section, you see a number of wells that do reach the Devonian but a couple of wells that don't quite get to the Devonian but they see the Mississippian and other formation tops, and so we've projected down to the Devonian.

And starting on the left-hand side and moving to the right, you just see generally the dip getting deeper as you go towards A, A -- I mean towards A prime. And you can kind of use the dip established between wells to project what you would expect to see at the next well. And any strong departure from that would be indicative of possible fault. On this particular cross section, just straight downdip through the area, we see generally just a uniform southeast dip, without any strong structural indication of faulting.

And this is -- I'll stop for a moment and say this is the type of information that would be requested in Texas if these wells were just a few miles south and a seismic event showed up within the area of review, the circle -- 100-mile square circle. This is the kind of evidence we would put on that would get reviewed, but ultimately you would get a permit of some kind. It might have some conditions on it.

Q. And let me stop you there. I think what you were saying earlier, though, was that unless there is a seismic event of a certain magnitude, you don't even get to this level in Texas, right?

A. No. If this -- if they had drawn the state line different in 1845 or whenever -- the Baker is only four-and-a-half miles from the Texas state line, and that's just a line on the map. The geology in the basin is very similar on both sides of that line. And that particular -- I mean, both of these locations would be looked at. They would see that there is no USGS events within the circle or, you know, of any kind, and it just goes on down the line and gets approved.

Q. Administratively?

A. Administratively.

If there were events in the -- within the circle, then it would go into this other basket of how many events are in the circle and is it at a depth similar to the injection and all these other factors that would be considered.

So if we look at B, B prime, B, B prime is a strike cross section. It's not -- it's further to the northwest primarily because we were looking for control points that went a little bit deeper. But what you see is at the top of Barnett and Mississippian, you know, that cross section is drawn such that if you look at the structure map, you should see very little -- very little variation in dip -- I mean depth between well to well to well across this line, and that's what you see at the correlative markers.

So in other words, we've taken that extra -- we've gone that extra step and provided the same kind of information that would be provided in the event that you were -- were in a seismic-active area, as we testified to last time and as the map shows today, and there have not been any seismic events in this -- this area.

Q. And just to clarify, too, one of the things you talked about was that a fault has to be oriented in a certain way for induced-seismicity concerns to be triggered. Here I think you testified, for Laguna and Baker, that there aren't any faults. The closest one is ten miles. But in the event, they're not oriented in a way that would give rise to the type of concerns that were identified in the EPA manual?

A. Yes. And we can probably address that with the next exhibit on Number 5.

Q. Okay.

A. The hypothetical that we went through on Exhibit 1 had a fault oriented parallel to the stress field, which, in this particular area, is about north 45 east. So that would be considered a fault of concern, a fault that's oriented -- that you can identify and is oriented in that direction.

Now, the faults that the BEG has shown in this area are oriented totally different than that. If you look at Exhibit 5, Exhibit 5 is -- the BEG fault traces are shown as the black lines, and then the corresponding structure contours that the BEG had derived or mapped for the Ellenburger are also shown on the map. And it doesn't come out very well on these small copies, but it's better on the larger copy that we can provide. But you see little plus marks on the map. You'll see one -- if you look on cross section, C, C prime, the second point, that 01137, there's a little plus sign there. That's the sparseness of data that the BEG had when they made these maps. And so I think we'll all agree that even these BEG fault traces are highly suspect, and they're from 30 years ago, when there -- there weren't nearly as many data points as there are now as shown on the previous map. We've got a lot more data in here to assess whether or not we believe there is a fault in the area. And that's what we look at with cross section C, C prime and D, D prime.

If you keep -- again, keep this map out, the map under Tab 5, and we're going to look at cross section C, C prime, which suggests, based on the BEG's mapping, that between the second and third well on that cross section, you should step up. In other words, going from C to C prime, between that second and third well, you should step up about 800 feet. They're interpreting an 800-foot fault in there. And this is the one that we've described as being "nearest fault to the analysis" or the Laguna Salada. Well, we built cross section C, C prime, which is under Tab 6, and, again, between wells -- the two wells in the middle, we should have seen a step-up on the third well from the left, according to this -- this BEG interpretation, and it's not there. It's the exact opposite. It's just dipping off into the basin, and there is no evidence of a fault between there.

So, I mean, here is an example where we're being graded on that fault over and over and over, but yet there is very little evidence to support that that fault is there, at least in this particular area. There may be someplace else along that fault, but you certainly could not have projected a fault across all these counties with two or three points on one side or the other. I mean, it's just -- it's peer-reviewed, but, you know, it -- it's a -- it's a published work that's now accepted as being meaning, well, that's where the fault is. And our more detailed site analysis says not only is that fault not down there, we don't see any faults in the area of the Laguna Salada areas. That's C, C prime.

Now, we're going to look at D, D prime. And you'll notice again between the second and third well, the BEG is saying, We believe there is a fault in there. And when you look at D, D prime, I think most of us would agree, with a limited amount of training, you would see a very large fault between the second and third well on that.

So, I mean, this is an example of the type of work that needs to be done, to site-specific screen wells and not geographically just say, Push them this distance apart; we'll be okay. You can do that, and then if you allow wells to be drilled near this situation, then you didn't effectively do your job.

Now, this fault is not oriented optimally, but it's clearly a fault. There is clearly a fault there. And so --

MR. BROOKS: Where is that?

THE WITNESS: If you look at this map here, which was -- what exhibit was that? 6?

MS. BENNETT: It's this one, Phil. Phil, it's the D, D. Yes. It's right here (indicating).

THE WITNESS: It's the D, D prime.

So, you know, there is no disputing that the BEG sees a fault there. I see a fault there. Geomap, who we subscribe to, which is a subscription service -- I've got the access to that map, but I can't really copy it and show it to you guys because it's licensed -- they have faults there. And I can tell you that their maps around the Laguna Salada look almost exactly like mine. They don't have any faults in those areas. And they go to a much higher-level degree of analysis and study in building their structural maps because that's what people are paying for, is a good product. And these looks from 50,000 feet up that says this is what's going on out here are just not sufficient.

Q. (BY MS. BENNETT) So -- and the D to D prime fault that you noticed and that is pretty clearly evident on the cross section, that's a long ways away from the Laguna Salada, isn't it?

A. It's a very long ways away from Laguna Salada.

Q. And it's not optimally oriented either?

A. It's not -- we've analyzed that one a number of times. I mean, we've presented a number of permits in here for NGL and others, and there are a lot of wells being permitted over there. But it's typically on the order of -- 4,000 pounds is necessary to cause fault slip based on that fault orientation, and the .2-psi-per-foot limit is going to keep you from ever getting there, even right at near wellbore, much less some distance away from the wellbore to the fault.

Q. So just to recap, you actually identified logs -- well logs, you did cross sections, you prepared contour maps for these specific areas, and there was information for you to rely on to do that?

A. Yes. That's the type of analysis that I would typically do across the state line if there has been some concern of seismicity. We would be requested to do a structure map on the top of the injection interval, a structure map on the base of the injection interval, cross sections in a dip direction, cross sections in a strike direction and then, after all that data analysis, run the FSP based on the best available inputs that can be put into the model, and we present that data. It gets reviewed, and it will typically -- I've not come across one that didn't at least at some point result in some kind of permit. There may be rate reduction, or there may be requests to install a seismic monitoring system, but again, those are -- those are conditions that never even come in until there's been an event within the area of review, and we have none here.

Q. And you did all of that for the Mesquite applications -- or for the Mesquite hearing exhibits when we were here last time, right? You did the FSP analysis?

A. That's correct.

Q. And you showed no -- zero, as I recall, likelihood of fault slip probability?

A. Well, the biggest problem with that model is there were no faults in the area of review to calculate what the pressure would be at the fault. So yeah, the probability was zero because there were no faults to calculate the pressure at that specific fault.

Q. And you've had a chance to look through Mr. Goetze's and the OCD's exhibits, right?

A. Yes.

Q. Do you see anything in their exhibits that aren't similar to your FSP analysis, like the cross sections or the contour maps, for this area?

A. I think the closest they came was maybe Dagger Draw, but that was not any -- an analysis done by staff.

It was just a published paper. There was no site-specific geology presented in this area, not even a type log, that would show us what sections we're talking about.

Q. And, again, Mr. Goetze, when we were here earlier, noted that you have testified a lot before the Division. And, in fact, you have a lot of experience with the Texas Railroad Commission process, right?

A. Yes, I do.

Q. And in your opinion, if this was across the state line, this application would have been administratively -- these applications would have been administratively approved?

A. They would have. There would -- you know, as he stated, we do not have a spacing rule in the state of Texas. And so it is my understanding, everything I've heard here today, that's the only thing that's kept this one from being administratively approved.

Q. Thank you.

MS. BENNETT: I don't have any more questions for Mr. Reynolds.

EXAMINER JONES: Mr. Brooks?

MR. BROOKS: No questions.

MR. BRUCE: Questions, Mr. Padilla?

MR. PADILLA: None.

EXAMINER JONES: Questions?

EXAMINER McMILLAN: I don't have any.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. I'd just like to correct the record. I said earlier that -- I quoted you from last time saying that these faults in this basin were 30 degrees from vertical, and you said now they're 80 degrees. They're basically almost vertical.

A. They're almost vertical. Yeah, I heard you say that earlier.

Q. Yeah. I'm sorry that I said that.

A. That's all right.

But you were correct, the fault at 30 degrees is similar to one that's at 90 degrees, because 60 degrees is the optimal dip angle that would initiate slip. Not only optimal azimuth is important, but dip angle closer to 60 is more critical. And the closer you get to 90 or below 60 would be less likely slip, so it turns out 30 is the same.

Q. So you're talking about like a vector type system.

Okay. So if your stress now is so much different than the stress when those faults were created, what happened out there that caused the change

to the stress regime?

A. The orientation of the faults versus what the current stress field is?

Q. Yeah. Yeah.

A. You know, it's just things have rotated around over geologic time. As you -- for example, the current-day stress in the Delaware Basin rotates from about north 30 east to 130 degrees as you get further south. So as you get into Reeves County and other counties, the two coincide. The ancient faulting and the current-day stress are more in alignment. So it's just changed over time.

And, you know, you asked about data collection. You know, that would be one thing that could possibly be collected, is are we using the right assumption for the -- for the stress at that depth. You know, wellbore breakouts are an indicator, and then there is also -- there are particular logs that can be run that will --

Q. Will orient the dipole sonic?

A. Yeah. That will give you the rose diagram and show the orientation of the -- the stress field. So, you know, that's something that could happen.

But your question earlier to someone was gathering more information on the confining layer, the

Simpson. Well, we're never going to get that if we're stopping 100 foot at the Montoya every time.

Q. But if you don't have to stop --

A. Right.

Q. -- then you have to plug the well back, and that's not very successful either.

A. That's right.

And I can tell you from having looked at all those examples that were cited today and all the examples in Texas, there -- there aren't instances where the well was drilled and they blew out the confining layer. That was not the issue and the reason for seismicity. The issue and the reason for seismicity was proximity to the fault, and that fault provided the break through the -- through the seal, not any specific thickness or anything like that.

Q. The injectivity is a function not only of the porosity but the extreme big thickness of the, quote, unquote, "Devonian" in this area. That's why it's such good injection.

A. Right. And if we were talking about a 50-foot interval, the pressures that calculated these faults would be considerably higher because our container is so much smaller.

Q. Okay.

EXAMINER JONES: Anybody else have any questions for this witness?

Go ahead.

CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. Well, I was just -- Mr. Reynolds, did you go through these materials that Mr. Goetze presented, the articles?

A. I've -- I've read probably all of them at some point over the last three years, but I can't say that I've read them all recently. I saw -- I looked at all of them last time and saw what they were and said, "Yeah, I've looked at that one or I haven't," and that kind of thing.

Q. Well, I mean, what struck me in reading these articles, which is the same thing I quoted to Mr. Goetze, was that several of the articles, the ones focusing on Oklahoma, the Raton Basin, are all talking about the impact of cumulative injection volume being associated with the rise in seismicity, along with depth. And so your whole discussion is talking about faulting, but I don't see -- faulting is not discussed in these articles. It's all talking about volume.

A. Well, there is a fault in every one of those. I don't think there is any one of those where they say a well just out somewhere in a geologic province has injected too much would be a cause of induced seismicity. It's -- it's cumulative volume in areas near faults, is what it is.

Q. And so just to clear up Mesquite's position, that is that you're okay with a one-mile spacing but not a mile and a half?

MS. BENNETT: So just to be clear, Mr. Reynolds can give his position but not Mesquite's position. He can give his.

EXAMINER BRANCARD: Well, he's Mesquite's witness.

MS. BENNETT: He is, but I don't know that he -- I mean, I would rather answer that question if that's okay. What I can tell you is that Mesquite is comfortable with the 1.5-mile spacing requirement going forward but is asking for these three wells to be analyzed under the regime that they understood to be in place at the time. And they also are saying that even if the 1.5-mile spacing requirement is applied here, it has been not shown to be necessary. And I think Mr. Reynolds concedes that, that it hasn't been shown to be necessary to apply that here.

THE WITNESS: Yeah. To answer your question, it's not only my opinion, but from what I can tell, it's the State of Texas and the State of Oklahoma and a number of other states' position that they don't view that as the most critical element, or they would have imposed some sort of rule between those spacing already. I mean, those are areas that have a tremendous amount of seismicity, much more than what has been seen in southeast New Mexico, and none of them have implemented a between-well spacing, but some of them have identified -- an example in Oklahoma, the Prague area and the fault of concern there, they drew a buffer around the faults and imposed rate restrictions on all the wells within that buffer. So this concept of cumulative volume wasn't applied to the whole basin. It was only applied to the wells within a certain distance of that fault, because wells some considerable distance from a fault are not going to raise the pressure many, many miles away. So it's recognition by the State of Oklahoma that they took action based upon a geologic area around a fault, not just arbitrarily over an entire basin.

Q. (BY EXAMINER BRANCARD) And the action they took and the action shown in Exhibit 11 is rate limitations?

A. Exhibit 11, I think, was the Texas package; was it not.

Q. Where they had a category of A, B and C, and

one was 10,000 barrels day, one was 20- and one was 30-.

A. Yeah. But that is not based on a particular fault. That is just based on how many seismic events showed up in the area of review, how much cumulative volume is permitted in the area of review. There are about five factors that go into assigning an A, B or C grade on that analysis. And an A grade will get you 30,000 barrels a day. A B will get you 20,000 barrels a day, and a C will get you 10,000 barrels day. And if you will agree to monitoring and some sort of mitigation plan, you can get an extra 10,000 barrels. So you can go up to 40, 30, 20. But that specific program is -- is based on what showed up within your 100-square-mile review, not necessarily certain wells around a certain fault.

RECROSS EXAMINATION

BY EXAMINER JONES:

Q. Is that all out of Austin, or is that District 8, District --

A. They are only imposing that in the Delaware Basin right now. I'm not seeing that be forced in the Eagle Ford, but I can see it heading in that direction, as applying a similar rating system and condition system to other areas.

Q. They permitted, though, out of Austin, right?

A. Yes. Yes.

CONTINUED CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. I just want -- your -- your entire focus is on the faults and the knowledge of faults, so I just want you to comment on this line that's in this latest article, this Lund Snee-Zoback, on page 132. Near the end, they say, "We consider the greatest uncertainties in the map to be the lack of knowledge of subsurface faults." So I think --

A. Yeah. If you look at the Lund Snee paper, you will see that those fault traces that they've used are simply the BEG fault traces. They have not gone into an in-depth area of review.

They also go on to state in that paper that they didn't -- the only factor they considered was fault azimuth and if a 4 percent pressure increase was seen at the depth interval of the fault, whether it would slip or not. So they didn't factor in the specific parameters of the injection interval or the other injection in the area, which our FSP model does.

The model they run in that paper, it simply takes those fault traces and their orientations and say, "Are these faults optimally oriented to type slip or not?" They don't take into consideration any of the --

where the injection wells are or what depth they're injecting or anything. It's, again, a 50,000-foot look at a basin. And they identify, for example, these faults in this area just based on azimuth alone. They see them as low risk.

Q. Well, I guess the concern for the Director would be if we base the analysis on absence or presence of faults and we have this statement here talking about the lack of knowledge of subsurface faults, is that a problem here? I mean, are we basing our whole theory on something that we don't know, that there is a real lack of knowledge about?

A. Well, I would say -- it's been my experience that there is a large gap between the academics world -- academic world in what they view as the data that they have available to them and the E&P world. I mean, an example is we looked at 50 data points in here, and the BEG had zero within our area of review. And those are the faults that are in the Lund Snee paper, is -- I would make the same statement if I hadn't mapped it myself and I was relying on someone else's work that was from a sparse data set. I would say, you know, "I really don't know where these faults are." I would -- I would make a comment in that paper because I didn't do the mapping. And so I would have to protect myself and say, "This is what my analysis is based on these faults, where they're located, that came from some other source," which tells me, you know -- I mean, it's a good paper, but if you're not doing the actually nuts-and-bolts work, you're not going to reach a comfort level of where the faults are and where they aren't.

And, you know, to get there, you need to -- if you've deemed it an area of concern, you need to ask for information like what we've provided, structure maps, cross sections, things that you can look at and say, "You know what, I don't like the way those contours are grouped up right there. Maybe that is a fault. What's the cross section show if you drew a cross section right through here?" And then the data would reveal whether it's a concern. If it is a concern, maybe you go one step further. If you want this permit, you need to go buy a seismic line or something. But that's not to say that should be required on every permit unless there is data that indicates there is a concern.

But to answer your question, the reason there's so much focus on the fault and faults and whether or not there are faults is that's what the software is. It's a fault slip potential based on putting water into the ground in a certain formation.

Will it cause fault slip? That's where slips occur, is along faults. They don't just occur out in the middle of the basin where there are no faults.

MR. BROOKS: May I ask a follow-up question?

EXAMINER JONES: Yes.

CROSS-EXAMINATION

BY MR. BROOKS:

Q. I forgot your name already. I'm sorry.

A. Todd Reynolds.

Q. Okay. Mr. Reynolds, you used the term "area of review." I'm not sure exactly in what sense you used it because you said there was no -- as I understood your testimony, you were saying that, in principle, you don't have to worry about induced seismicity unless an adequate proper fault analysis does not disclose the existence of a fault within the area of review.

A. Well, first answer to the first question, my reference to area of review is 100 square miles.

Q. Oh, okay. So you're not talking about --

A. A much larger circle.

Q. You're not talking about one-mile or one-half-mile area of review?

A. Not the notice circle or any of that. We're talking 100 square miles.

And then the statement was it doesn't rise to the level of FSP analysis, cross section, structure maps and all these things unless there's been a historical seismic event within that 100-square-mile area of review, and that would trigger doing all this other analysis.

Q. Historical means what? What period of time? We usually distinguish between historic time and geologic time.

A. Sure. Well, historical would be if it's in the archives. Someone has recorded an earthquake in that area on an instrument. But, you know, whether or not there is something in a cave and someone drew a picture and said, "The earth shook some other time ago," that's not what we're talking about.

Q. We're talking about within a period of time that scientific observation of earthquakes -- of tectonic events has been recorded?

A. Yes. Because if there are faults out here, there was an earthquake at some point in time when that fault moved, but the --

Q. But if you don't have -- if you do not find a fault from other evidence or you have not identified one -- let me rephrase. Let me start over.

If you have not identified a fault from geologic evidence or found a record of one, historical record, then you don't have to worry about them if they're outside this 100 -- you said 100 square miles?

A. Yes. What -- what triggers that additional analysis in Texas is -- I'm not quoting our rules there -- is for every saltwater disposal well permitted in the state, you have to draw this 100-square-mile circle around it and search the USGS archives, and if there is a seismic event of any magnitude that has ever occurred in that circle, then we have to do all this other additional analysis.

Q. Your -- your testimony is that this 100-sqaure-mile area is, from a scientific point of view, adequate to disclose any faults that might have problems?

A. It is adequate to the relevance of the wells that they are the subject, is that those wells would not impact -- there may be critical faults located outside that area of review, but a well in the middle of that 100-sqaure-mile area is not going to impart a pressure change outside that 100 square miles.

Q. But you're not testifying that you need not be concerned about any faults that are outside the one-half-mile area of review provided in the New Mexico UIC plan?

A. No. If there was a fault outside the half mile, it would have been inside my 100 square miles.

Q. Right.

Thank you.

A. And I would have -- I would have -- it would have been in the model.

Q. Thank you.

A. So that's why the area of review is much greater for the seismicity for review than it is the notice element.

Q. Okay.

MR. BROOKS: Nothing further.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Just quickly, the availability of listening devices and how would Mr. Goetze know if this area was -- had a 2.0, real small, seismic event? How would he know that if he's looking at a permit application? In other words, is there enough monitoring devices, or are they public, or --

A. Well, the USGS is a public archive record that is searchable. You put in the coordinates of this well and give it a radius, and it will return any events that occurred in that. Now, up until recently, that's all we had in Texas. We did that, and the USGS detected it, and it started this process. Now, we have the TexNet, so we're picking up a lot of the smaller stuff that the USGS didn't pick up, typically events in the 2.0 magnitude, because their monitoring stations are so far apart from each other. They just don't pick it up. It's not a big enough earthquake to do that.

There was an array that went all the way across the country here about eight years ago and set up in sections of the country for two years. And they set up in New Mexico for two years, and then they moved it over and they set up sections of Texas for two years. And then they -- you know, they moved east. That's data that could be analyzed to see, you know, when they had that tighter grid. It was a very tight grid of monitoring stations. Did anyone -- were there any events detected? Where were the active areas? That data can be looked at to determine that. It's been done in Texas by a number of researchers, and, you know, they found events that did not get reported by the USGS because they had this tighter array that was able to pick it up.

And the client, I believe, at the last -- you know, less than a month ago, we testified that the client would be willing to put monitoring stations in this area and share that information.

Q. So TexNet could be expanded up into New Mexico?

A. That's -- that's kind of up to TexNet to determine -- I mean, they could detect what's going on in New Mexico right now with a lot of the stations that they have, but they only report the stuff that falls within the borders of Texas. Now, the two systems could be merged together, and, you know, both parties could use the information.

Q. With all the activity going on, the drilling and the trucks and the -- they actually can measure real small events that are going on?

A. Yeah. The trucks and quarry blast and all those things have a distinct character that can be filtered out.

Q. Even the drilling?

A. Yeah. Yeah.

Q. And the fracking?

A. That's usually below the threshold of detection.

Q. Okay. Okay.

A. Except when those cause earthquakes, and they do from time to time, but they're small.

MS. BENNETT: May I ask a quick follow-up question?

EXAMINER JONES: Yes.

REDIRECT EXAMINATION

BY MS. BENNETT:

Q. In regards to the publicly available seismic data below 2.0 magnitude, didn't Dr. Steven Taylor submit two studies that you reviewed and that are included in the materials that we presented at the

hearing last time, our seismic monitors in the area?

A. Yes. NGL has a series of monitoring stations in this area, and we did present the results of any events that have shown up on those, as a result of those monitoring stations. And I think the highest magnitude was a 1.9, but it was not in this area. It was -- it was further to the east at least 20 or 30 miles.

Q. Thank you.

EXAMINER JONES: Okay.

MS. BENNETT: Thank you, Mr. Reynolds.

I'm guessing there are no other questions of Mr. Reynolds.

EXAMINER JONES: Do you want to admit --

MS. BENNETT: Oh, yes. May I please admit what we have marked as MRB-1, Rebuttal Exhibit Number 1?

(Mesquite SWD, Inc. Rebuttal Exhibit Number 1 is offered into evidence.)

EXAMINER JONES: Any objection?

MR. BRUCE: No objection.

MR. PADILLA: No objection.

MR. BROOKS: No objection.

MS. BENNETT: May I make a brief closing statement -- two closing statements?

EXAMINER JONES: Yes. We were going to --

Mr. Brancard, we were going to ask for

proposed findings from all the attorneys.

MS. BENNETT: Okay. Thank you.

May I make a brief closing statement.

EXAMINER JONES: Sure.

CLOSING STATEMENT

MS. BENNETT: Okay. It will be very brief.

I have two things that I'd like to say. First of all, as you may recall, I requested initially that these protests be dismissed because there was no technical evidence that had been presented, and Mr. Brooks objected to my request that the cases be dismissed -- or the protests be dismissed or the objections or opposition, whatever you want to call it, be dismissed because it was premature because we hadn't been given the opportunity to have technical evidence.

And just as a reminder, Mr. Brooks, in his February 18th email, stated, "Since the 1.5-mile distance is not a rule provision, it does not control unless a priority of the application in that particular case is shown. The Division has the power to issue rules or orders to regulate disposal of waste to protect the environment. If either party were to demonstrate by technical evidence that both wells now proposed cannot be operated consistently with environmental protections, the Division should enter an appropriate order."

The Division has not entered or identified or presented any technical evidence in the case today that relates to these wells, that show that these wells cannot be operated consistently with environmental protection. The unrebutted -- the unrefuted evidence by Mesquite's experts shows that these wells -- these two wells can be operated consistently with environmental protection.

So, again, I would renew my request that the opposition to these applications be dismissed and that these applications be returned to the administrative application process and be granted administratively posthaste.

Beyond that, I would also just say that I think the evidence today that came out demonstrates that this 1.5-mile screening tool is not being applied fairly. It's not being applied across the board. In fact, just two weeks ago, there was a hearing that went forward where a well was proposed to be closer than 1.5 miles to a Mesquite well. If something doesn't scream arbitrary, I think that should. That well was allowed to go forward to hearing unprotested, unopposed, and it's closer than 1.5 miles to the very well that's at issue today. That doesn't seem like a fair or a reasonable approach. It seems very arbitrary and ad hoc.

I would also just point out that throughout this period of time, the Division had the EPA report in 2015.

The Division, in 2017, says there is no spacing requirement.

The Division, in 2018, January 2018, approves the Black River application, which is a well closer than 1.5 miles to another well. The Division, in June 2018, approves an application for a well closer than 1.5 miles to another well. Mesquite submits its applications in July. According to Mr. Goetze's notes, there are meetings that occur without Mesquite's attendance that occur between July and December. And in December 2018, Mesquite's applications are denied based on a rule, a requirement, a screening tool, whatever you want to call it, that was never provided to Mesquite, never given to Mesquite. Mesquite was never asked to provide any additional information. Mesquite would have. We did when we came to hearing.

So I feel that what Mesquite is asking for is entirely reasonable. They want the three applications that they submitted in July of 2018 -- July 2018 to be reviewed and approved under the July 2018 status. It's clear that between July and December, the

Division's policy or the Division's ideas changed. Those changes were never communicated to the operator except as on an ad hoc basis, and Mesquite shouldn't be held to that ad hoc determination. Mesquite's application should be approved.

I also wanted to briefly make a statement on behalf of the Baker Ranch. And Mr. Baker's attorney could not be here today. But Mr. Baker and Mrs. Baker are with me, and they've asked me to read their statement into the record. But they're willing -- Mr. Baker is willing to come up and stand beside me while I read it.

So this is a statement on behalf of Jesse Baker and the Baker Ranch and Mesquite SWD's application for an SWD well in Case Number 20472.

"This statement is made on behalf of Jesse T. Baker and the Baker Ranch by their attorney of record, James T. Roach

"Jesse T. Baker and the Baker Ranch fully support Mesquite's application for an SWD well on the Baker Ranch. Mr. Baker and Mesquite entered into a contract for the drilling and operation of SWD wells that is the subject of this application. The contract was entered into long before OCD representatives took the position that SWD wells should have a 1.5-mile spacing. There was not even a suggested requirement when Mr. Baker and Mesquite entered into the contract and there was no notice that such a suggested requirement was going to be asserted by OCD. Furthermore, there was no knowledge or information then and now that there was a reasonable basis for such a requirement.

"Mr. Baker opposes any restriction on his right to enter into the contract with Mesquite and further opposes any restriction on Mesquite's and Mr. Baker's rights to perform the terms of the contract formed before there was any consideration of the 1.5-mile spacing restrictions. Mr. Baker opposes the attempt to restrict performance of the contract and to restrict the use of his land by such an arbitrary decision made after the formation of his contract.

"Mr. Baker and the Baker Ranch have worked with Mesquite SWD, Inc. for over three years. Mesquite has always treated Mr. Baker fairly and courteously and the working relationship has been very good. Mesquite has been respectful in the way it operates on Mr. Baker's land and causes no disruption in the operation of the Baker Ranch. Mesquite has always been very eco friendly in its operation of the SWD well on the Baker Ranch. Mr. Baker is impressed with how well

Mesquite is able to operate an SWD well and be so accommodating to ranch operations.

"Mr. Baker and Baker Ranch request that the Mesquite SWD, Inc. application for the drilling and operation of an SWD well on the Baker Ranch be approved."

Thank you.

Thank you.

EXAMINER BRANCARD: Yeah. We'd like a copy of that.

EXAMINER JONES: Okay. If all the parties will give us proposed findings -- unless you want to react to --

CLOSING STATEMENT

MR. BROOKS: I want to make a couple of observations. I won't say it will be brief because some of my questions -- it's been asked of me many times: Why are lawyers' arguments called briefs when they never are? But it will be much briefer than Ms. Bennett's closing statement.

I want to say two things. One is that there is adequate technical evidence because Mr. Goetze, who is a qualified technical witness, testified that it was his opinion that a 1.5-mile separation distance should be imposed in these cases in the locations where these wells are located. And it was adequate -- there is adequate basis for it in the papers filed because if the Division were to impose by rule -- were to task itself to impose by rule restrictions that would limit cumulative injection in an area -- you define -- you tell me what area and whatever the size of the area is. If you're to restrict cumulative injection into a formation in any size area, one way of -- one reasonable way of approaching it would be to reduce -- would be to limit the number of wells in that area because a larger concentration of wells in an area of a given size will result in more injection if the wells are the same volume as to each well and if they are located within a certain area -- defined area.

That's all I have to say.

EXAMINER JONES: So you oppose the motion to dismiss?

MR. BROOKS: Well, I oppose the motion to dismiss if it is indeed a motion to dismiss. It's a motion to summarily -- to issue an order, I take it, that summarily remands this case to the administrative process with the direction that the applications be granted, not for further consideration.

EXAMINER JONES: Okay. Mr. Padilla.

MR. PADILLA: I don't have a closing

statement or argument. I would request that my closing argument be deferred until after our case.

MR. BROOKS: I have no objection to that.

EXAMINER JONES: Okay. So the record in the Solaris-Blackbuck matter is going incorporated into the Mesquite cases?

EXAMINER BRANCARD: Vice versa.

MR. PADILLA: Well, at this point we have to separate the requested findings for the Mesquite case, and I shouldn't have to submit requested findings on behalf of Blackbuck in these cases. But now I think we can separate so we will file separately.

EXAMINER JONES: Okay. So we'll just get from the two antagonists or --

MR. BROOKS: Well, yes. We should now finalize the case as to Mesquite. We can't finalize the case as to the other Applicants until we've heard their rebuttal.

EXAMINER JONES: As far as the deadline for the proposed findings, what do you think? What do you propose?

MR. BROOKS: Well, I have no real input on that at this point, but I will respect any deadline that is imposed. I would think we would need at least a week, to be reasonable, given the magnitude of the evidence. And it would help a whole lot if we could have the record, but I have no idea when the record will be ready, and I know the court reporter is overwhelmed.

Can you give us any idea when you could get this record ready?

(Discussion off the record with the court reporter.)

MR. BROOKS: I'm not in a hurry to get the record, but I would like at least a week after we get the record to prepare findings and conclusions.

EXAMINER JONES: This (indicating) is of record already.

MR. BROOKS: Oh, that's the first hearing.

EXAMINER JONES: Yes. We have half it already.

MR. BROOKS: So we only need to concern ourselves with -- well, it would depend. But I would like some time after we get the record, today's hearing, but it does not have to be in a week.

EXAMINER JONES: You're not really asking for proposed orders or post drafts, just proposed findings?

MR. BROOKS: Well, whatever you set will be complied with.

MS. BENNETT: I'd like to suggest, if we

get the materials -- I heard you saying maybe the week of July 8th through the 12th would be the time the record would be completed, and if we need a week to review those, I would suggest that the findings of fact be submitted, as a special birthday present to me, on July 25th.

MR. BROOKS: That would be acceptable with me.

EXAMINER JONES: Six months before Christmas.

(Laughter.)

MS. BENNETT: I would suggest July 25th as a deadline.

MR. BROOKS: I would also note one thing about July 12th. It's a little embarrassing to admit, but I guess not really.

(Discussion off the record.)

EXAMINER BRANCARD: Okay. So proposed findings. I mean, you don't want an order, but at least sort of what you would want the Director to include, if there are conditions or not, et cetera, that you would offer that. That would be helpful.

MS. BENNETT: Thank you.

And so are these cases then taken under advisement, or how does that work at this point?

EXAMINER JONES: They're taken under advisement.

These three Mesquite cases, Cases 20472, 20313 and 20314 are taken under advisement.

The matter is closed.

MS. BENNETT: Thank you.

(Case Numbers 20472, 20313 and 20314 conclude, 5:16 p.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

I FURTHER CERTIFY that I am neither employed by nor related to any of the parties or attorneys in this case and that I have no interest in the final disposition of this case.

DATED THIS 11th day of July 2019.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2019
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