STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

BEFORE THE OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

Submitted by: Goodnight Midstream Permian, LLC

Hearing Date: February 24, 2025

Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

MCGUIRE, TOMASTIK, DAVIDSON, KNIGHT, MCBEATH, & LAKE TESTIMONIES AND REBUTTAL EXHIBIT PACKETS

PART 1

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

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO

CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO.

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24020, 24025

APPLICATION OF GOODNIGHT PERMIAN MIDSTREAM, LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.

DIVISION CASE NO. 22626
ORDER NO. R-22869-A
COMMISSION CASE NO. 24123

SELF-AFFIRMED REUBTTAL STATEMENT OF PRESTON MCGUIRE

1. My name is Preston McGuire. I work for Goodnight Midstream Permian, LLC ("Goodnight Midstream") as the Geology and Reservoir Engineering Manager. I provided direct written testimony in these cases that were filed with the Commission on August 26, 2024.

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. B
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

Rebuttal Summary Bullets

- Empire has failed to provide evidence of communication between the San Andres disposal zone and the Grayburg producing interval. Their claims rely solely on supposition without demonstrating the presence of through-going fractures that would allow fluid migration. The alleged field-wide oil production decline does not stand up to scrutiny, and Empire has not presented well-specific production data to support its claims. Furthermore, they cannot show changes in produced water chemistry that can be attributed to San Andres disposal operations. The sole basis their experts rely on to allege fluid communication is increased sulfate concentrations but that is not diagnostic and measured sulfate levels are well within historic ranges.
- The claimed ROZ in the San Andres disposal zone lacks supporting evidence, does not align with established field data, and is unreliable. Testing using the de-pressuring production method, as described by Empire's witness, establishes that the water supply wells produced enough volume to develop a gas drive, which should have resulted in some oil production if recoverable oil were present. Additionally, Dr. Lindsay and Dr. Trentham acknowledge that the oil saturation cutoff defining a ROZ is 20%, and Dr. Trentham concurs with Goodnight's placement of the ROZ base above the San Andres disposal zone, as shown in Goodnight Exhibit B-32.
- Dr. Buchwalter's reservoir simulation model is incomplete and does not account for key factors affecting the Grayburg and San Andres reservoirs. It excluded numerous San Andres water supply wells and their volumes, as well as significant

San Andres SWDs and decades of injection data. Importantly, the model excluded edge water from the Goat Seep aquifer into the Grayburg producing zone, omitting a critical hydrodynamic factor as discussed by Dr. Lindsay. Additionally, it does not reflect mechanical changes made to producing wells over time or the inherent geological complexities of a carbonate ramp system, making it an inaccurate and unreliable representation of reservoir behavior.

- The OCD's new elevated concern with San Andres injection potentially communicating with the Capitan Reef is unfounded. Goodnight has consistently engaged with the OCD regarding the Capitan Reef in prior applications and hearings, securing approval for 12 San Andres SWD permits. There is no clear justification for the OCD's newly heightened concerns. Much of the OCD's analysis is based on outdated 1970s research by Dr. William Hiss, which incorrectly assumed a stratigraphic connection between the San Andres and the Capitan Reef. Modern peer-reviewed studies confirm that no such connection exists. Goodnight has conducted updated quality control on the San Andres data in the Hobbs Channel area, demonstrating that the Hobbs Channel (accurately described as the Hobbs Outflow) is limited to the overlying Artesia Group, where a known stratigraphic and hydraulic connection with the Capitan Reef exists. Additional and updated chemistry data supports this re-analysis. Moreover, water quality data confirms that the Capitan Reef in this region far exceeds the criteria for an Underground Source of Drinking Water (USDW).

REBUTTAL TO EMPIRE'S CLAIM THAT THE BARRIER BETWEEN THE DISPOSAL INTERVAL AND THE PRODUCING INTERVAL IS INEFFECTIVE

2. Empire has failed to show that the barrier between the San Andres disposal interval is ineffective. They have not shown any data capable of withstanding scrutiny that confirms communication between the Grayburg and Goodnight's San Andres disposal interval. The San Andres disposal interval and the oil productive intervals in the overlying Grayburg function as separate reservoirs. Below is a summary of my rebuttal points relating to Empire's claims that the barrier is ineffective.

- Core data confirms the presence of a barrier. No through-going fractures in the core would allow communication between the Grayburg producing interval and Goodnight's disposal zone and the measured vertical permeability confirms the presence of an effective seal.
- The decline in EMSU total oil production is not abnormally high as claimed by Mr. West, who appears to be cherry picking data. Declines are reasonable and predicted. Empire has provided no other well-specific production data that is diagnostic of communication.
- Empire has not seen a change in the produced water chemistry that exceeds normal variability. Produced water from the EMSU Grayburg wells has changed very little. Any minor changes identified are within the range of historic Grayburg water chemistries following waterflooding and can be attributed to in-zone operations with no indications that water from Goodnight's produced water disposal interval came through fractures into the Grayburg oil producing interval.

Fracture Claims

3. Dr. Lindsay shows multiple core photos from the EMSU 679. All photos are of rock above the permeability barrier, except for one. Empire Exhibit B-34 is a core photo from the EMSU 679 from a depth of 4,335 MD, which is within the confining permeability barrier. The photo shows a fracture, but the fracture has been filled with calcite cement at some point in the geologic past and is no longer a conductive pathway for fluid. The vertical permeability from this depth in the core report is 10 mD, but this datapoint is within a long interval (~100 feet) where the vertical permeability is at or very near 0 mD as shown in Goodnight Exhibit B-27. This long interval of non-permeable rock shown in the EMSU 679 core establishes that there are no long throughgoing fractures that allow for the disposal interval to communicate with shallower intervals. In his deposition and in his direct testimony, Dr. Lindsay discussed the concept of fracture halos outside of the core that cannot be seen. It is reasonable to assume that there may be additional fractures that are within the same interval as shown by Empire Exhibit B-34, but it is also reasonable to assume that these fractures have been filled with minerals as shown in the core interval and do not serve as fluid conduits.

4. Dr. Trentham discusses a similar situation where fractures heal and become barriers to flow that was observed at the Goldsmith Landreth San Andres Unit and West Seminole Field. He states the following on page 18 of his direct testimony;

> This supports the hypothesis that reactivation of the fault altered the facies distribution and resulted in the development of fractures at the reservoir level. These fractures were later filled by anhydrite as [sic] serve as a barrier to flow. This response is also reported to be present at West Seminole Field.

5. Dr. Trentham agrees that there is a barrier between the San Andres disposal zone and the overlying Grayburg producing zone. **Goodnight Exhibit B-39** are excerpts from his

deposition transcript that will be referenced multiple times in this rebuttal. See Tr. 72:6 – 73:12; 82:13-83:14; 89:17-25 (claiming there must be a barrier between the two zones).

6. All the other core photos and discussions of fractures in Mr. Lindsay's testimony, and the testimony of Empire's other witnesses, are not relevant as they relate to intervals that are above the confining layer that isolates the disposal interval in the San Andres. There is clearly a competent confining layer that isolates the San Andres disposal zone shown in the vertical permeability data from the EMSU 679 core. That is confirmed by the fact that there are different pressure systems associated with the producing Grayburg and the disposal interval in the San Andres addressed elsewhere in my testimony. All other independent factors that inform on this issue corroborate the conclusion that the barrier is competent, effective, and areally extensive, as discussed in my direct testimony and below.

Decline in Oil Claims

7. Mr. West contends that the EMSU has seen a steep decline in oil production during a nine-month period between November 2023 and July 2024 in his Exhibit I-18. Reviewing the data, it is obvious he cherry picks a nine-month period in an attempt to find a production decline. When looking at a longer period of production including months before and after his narrow analysis, the data shows there is no abnormal production decline. **Goodnight Exhibit B-40** shows graphs of EMSU oil production data that was provided by Empire as the public data was unreliable. The first graph shows EMSU oil production going back to January 1970. The graph shows the increase in oil production from initiation of the waterflood in late 1986 and peaking in 1997 before following an expected decline as the flood has continued to the present. The graph shows no abnormal changes in the production trend and the field is currently experiencing the shallowest decline in oil production that has been seen in the life of the field.

8. The second graph on **Goodnight Exhibit B-40** shows the same data as the first graph but is zoomed in to the last five years of data going back to when Goodnight began disposal operations. The added black line shows the producing well count and correlates to the y-axis on the right. The bracketed interval shows the narrow period that Mr. West was referring to in his Exhibit I-18. There is a major drop in production in March 2021 that was due to operational issues during the ownership transition from XTO to Empire. Empire did not provide two months of production data resulting in a data gap between August and November 2023. When expanding the view of data outside Mr. West's Exhibit I-18, the data does not show a major decline in oil production. **In fact, oil production recovered with a lower well count in the three months immediately following the interval depicted in Mr. West's exhibit.** This is an indication that the field is still capable of producing more oil with a lower well count and can be produced more efficiently—not that that there is impairment from vertically offset disposal. Additionally, the water production volumes in Mr. West's Exhibit I-18 are not increasing with time and are relatively consistent. One would expect that water production to significantly increase over time if Goodnight's SWDs were in communication with the Grayburg producing wells, which is not the case.

9. Empire cannot point to any wells that have been affected by Goodnight's disposal operations. If the claimed communication between the Goodnight disposal zone and the productive zone in the Grayburg was as pervasive as Empire claims, there should be many examples of wells having a significant change in production since initiation of Goodnight's disposal operations. Empire should be able to show at least some evidence of producing wells that have been watered out in the past few years by Goodnight's disposal through a change in the production profile. Empire has not, and cannot, point to any production data within EMSU that shows evidence of

impacts from Goodnight's disposal operations more than five years ago. Such evidence would have been touted in their direct testimony. **Instead, there is a history of compatible complementary operations in the EMSU between the Grayburg and San Andres. San Andres disposal operations have been conducted in the area for more than 60 years. Water disposal and oil production have been compatible in the EMSU over that time. If there was a problem, previous operators would have sought to shut-in and ban disposal operations in the San Andres long ago.**

<u>Claims of Premature Well Failures</u>

10. Empire claimed Goodnight's injection is, and has already, caused premature well failures and increasing plugging and abandonment liabilities in their motion to refer these cases to the Commission that they filed on January 3, 2024. Jack Wheeler made the following statement in his self-affirmed statement attached as Exhibit A in their motion.

> (3) injection of large volumes of water into the San Andres formation will prematurely water out Empire's wells, resulting in the loss of oil and gas, vastly increase operating costs, and increase plugging and abandonment liabilities decades earlier than would otherwise be necessary;[2]
>
> [2] Significant recent increases in well failure and well costs lead Empire to believe this is already occurring from the massive amounts of water being injected into the formations.

11. This allegation prompted Goodnight to issue a subpoena asking Empire to provide all data that supports this claim. Empire responded with a list of wells that require remedial action that was submitted to the BLM Office as part of its 2024 Plan of Development, listed as bates numbers OCD 23614-17 03327 to 03329. The list contains 92 wells that require remedial action which Empire alleges is due to Goodnight's injection. Twenty-six of the wells are in the AGU and unrelated to the dispute in this case while the remaining 66 wells are in the EMSU. These claims are not supported by any data including Empire's own analysis.

12. Empire Exhibit I-17 is an analysis estimating the alleged area of impact from five Goodnight SWDs as of June 2024. **Goodnight Exhibit B-41** is a re-publication of Empire Exhibit I-17. It has been revised to show the position of the 66 EMSU wells that need remedial action relative to Empire's analysis of the impacted area from Goodnight's injection shown by the blue shaded areas. To be clear, Goodnight disagrees with Empire's analysis. The point of the Exhibit is to show that Empire's own analysis does not support their claims. The date of first injection in the Goodnight wells is posted on the well locations in red. The 66 EMSU wells are colored by well type (pink are injectors, green are producers) and the date posted is the last production/injection date from the table Empire provided. It is interesting that this document was submitted to the BLM on February 27, 2024 but eight of the wells in the list had a last injection/production date listed after the document was created (see rows 2, 14, 40, 49, 53, 58, 62, and 66 on the table provided (OCD 23614-17 03327 to 03329)). Based on Empire's analysis of the affected area shown by Empire Exhibit I-17, which is the diameter of the blue color filled circles on the exhibit (which are shown as a maximum extent possible), there are at most four wells that possibly could have been impacted by Goodnight's injection. These are EMSU 364, 380, 417, and 419.

13. The EMSU 364 (API#: 30-025-04659) is currently an injection well that was drilled in November 1934 and was temporarily abandoned by XTO in 2019. A request was made to extend the temporary abandonment (TA) in February 2024 but the well failed a MIT at that time. The well was then plugged by Empire in June 2024. As described above, it is interesting that the report Empire submitted to the BLM stated that this well had a last injection date of March 2024, a date that was after the BLM report was created. There is no indication in the well file as to why this 90-year-old well failed the MIT in February 2024 but there is no indication that it was due to

Goodnight's injection. As discussed in Goodnight's direct testimony, the Grayburg has a long history of documented scaling and corrosion issue before and after waterflood operations commenced and this old well has been exposed to these conditions for nearly a century. The well was TA'd years before Goodnight began disposal operations and therefore Goodnight's disposal could not be the reason for the TA.

14. The EMSU 380 (API#: 30-025-04701) is currently an injection well that was drilled in October 1934 and was shut-in November 2021 according to the BLM report. The well then underwent remedial work in June 2023 to redress the packer. The well then passed a MIT and was returned to injection the same month. It is inconceivable that Goodnight's injection was the cause of the mechanical failure on the packer in this well. If Empire had evidence that Goodnight was the cause of this mechanical failure, then why haven't they produced it?

15. The EMSU 417 (API#: 30-025-04686) is a production well that was drilled before February 1942. The well records for this well are incomplete but a Certificate of Compliance and Authorization to Trasport Oil was filed in February 1942 and is the earliest document in the file. The well last produced in May 2023 according to the BLM report. Empire filed a Notice of Intention (NOI) to do remedial work in August 2024 to clean the perforations of the well with acid and to redress the pump and rod string design. A subsequent report on the well has not been filed indicating that the work has not been completed and the well does not appear to have been returned to production. Based on the NOI it appears that the reason the well has been inactive is due to issues with the rod and pump equipment. Goodnight's injection did not cause the issues with the pump and the rod string equipment. There is no indication in the production history that the well is seeing an encroachment of external water from Goodnight. Goodnight is not responsible for the remedial work this well needs.

16. The final well is the EMSU 419 (API#: 30-025-04695). It was drilled in August 1935. This well has the last date of production listed as January 2017; however, the well file shows this well was actually TA'd in December 2016 by XTO. The well was then plugged in February 2020, more than a year before Goodnight's injection commenced in the offsetting Sosa SWD. It is not possible that Goodnight could have impacted this well. Again, this is a 90-year-old well that has been exposed to corrosive conditions for nearly a century.

17. Out of the 92 wells that Empire claims Goodnight has impacted, only four fall within Empire's analysis of the affected area of the Goodnight's SWDs. One of these four, the EMSU 419, was plugged and abandoned before Goodnight began disposal operation in the San Andres. The review of the well files for the other three wells shows no indication that Goodnight contributed in any way to the need to remediate the wells. The vast majority of the EMSU wells were drilled about eighty years ago. **Wells of this vintage are expected to have issues related to degradation. Empire has not provided any evidence that Goodnight is impacting any of the EMSU operations.**

Claims of Change in Produced Water Chemistry

18. During Mr. West's deposition, he claimed that Empire's wells near Goodnight's SWDs are experiencing a change in the produced water chemistry that indicate that the SWDs are communicating with the shallower producing interval in the Grayburg. Based on a review of the produced water chemistry data Empire provided, this does not appear to be the case.

19. Empire provided water chemistry for seven wells that meet the standard of analysis for this evaluation. There must be three or more test dates to establish a change in TDS trend over time. Wells with two datapoints can agree or disagree with the final trend, but neither point is sufficient to establish a change in trend. In other words, there needs to be at least three datapoints to establish a trend. The seven wells that meet the criteria for analysis are the EMSU 321, 325,

377, 401, 407, 440, and 441. **Goodnight Exhibit B-42** shows the water chemistry analysis for these seven wells. The first page shows a table of the seven wells with the TDS, chloride, and sulfate values from the produced water chemistry analysis. The second page shows the graphical representation of the data on page one of the exhibit.

20. Empire and its expert witnesses have argued that increasing sulfate over time is a primary indicator that Grayburg producing wells are in communication with the San Andres, which tends to have higher sulfate concentrations. The graph of sulfate values shows that these values are flat to decreasing over time. If there were communication from the disposal zone in the San Andres into the Grayburg, the sulfate values should be increasing given the fact that Dr. Lindsay testifies that the San Andres has a high sulfate content.

21. The water chemistry data Empire provided does not indicate communication with disposal. If the SWDs were communicating with these producing wells one would expect that all the values discussed would be consistently increasing with time. While the TDS and chloride values have slightly increased over time in the EMSU 321, 325, 401, and 441 they are still well within the range of all the other wells for these values and well within the historic range before Goodnight commenced injection. See Empire Exhibit I-11 & I-12. None of the wells show anomalously high TDS and chloride values. None of the data provided is diagnostic that the Goodnight SWDs are in communication with the producing wells in the Grayburg.

22. Furthermore, because the EMSU has been under waterflood with San Andres as make-up water since 1986 any variations in produced water chemistry and sulfate concentrations could be a result of the waterflood itself or operational changes. For example, Empire could change the chemical treatment of the injection water before it was injected into the Grayburg that would result in chemistry changes or there may have been an adjustment of the water source for EOR

operations. In sum, more variables would need to be taken into consideration to understand what may be driving these minor variations in produced water chemistry. Proof that Goodnight's injection is the cause of changes in sulfate concentrations would have to rule out the EMSU's own waterflood injection of San Andres water. Empire has not done that. This chemistry data simply does not indicate that the Goodnight disposal wells have communicated with the Empire producing wells.

23. If Goodnight's SWDs were communicating with any of these wells there also would be a change in the production profile of these wells. Empire has not shown any wells where the production profile has changed that they can attribute to Goodnight's operations.

24. There are many things wrong with Empire's water chemistry story. Dr. Lindsay's proof of communication is based on water chemistry. He claims that there are three water chemistries that have been observed at EMSU: 1) Grayburg connate; 2) Goat Seep; and 3) San Andres. He states that each of these have a chemical fingerprint. Grayburg connate is identified as having 120,000 ppm TDS and is barium rich. Goat Seep is less than 10,000 ppm TDS and is sulfate poor. San Andres is less than 10,000 ppm and sulfate rich. He gave clear definitions with no data to support them, but we have publications along with field measurements to refute them. His simple conceptual modes does not match data obtained in the field. Dr. Lindsay's three-water model is unconfirmed by any data that Goodnight knows of. Dr. Lindsay has not provided any data and Empire has confirmed repeatedly that they do not have the data in their possession or control to confirm Dr. Lindsay's claims. When questioned about this in his deposition Dr. Lindsay stated that these results (the three chemical fingerprints) were presented to him by Dr. Alden Carpenter, a geochemist for Chevron, who did research on EMSU. Dr. Lindsay

does not have any of the data Dr. Carpenter presented but claims to have taken good notes. See **Goodnight Exhibit B-43**, Tr. 166:15-169:25; 174:1-176:1.

25. Water chemistry analysis at EMSU does not match Dr. Lindsay's chemical fingerprint. Measurements are drastically different, calling into question the validity of the notes from the discussion with Dr. Carpenter. **Goodnight Exhibit B-44** is an exhibit of fact submitted at the Gulf Oil unitization hearing seeking to create the EMSU in Case No. 8397. This exhibit shows that the make-up water (San Andres) had a TDS value of 66,077 ppm and the produced water (Grayburg) had a TDS value of 7,530 ppm. The San Andres is confirmed to contain sulfate. These TDS values strongly disagree with Dr. Lindsay's claims. This document from Case No. 8397 is strong evidence of what the water chemistry was before injection began.

26. The San Andres water chemistry can vary substantially. An example of this variation is shown in Goodnight Exhibit B-5, which appeared in my direct testimony. This is a paper published by Chevron in 1996, which Alden Carpenter was an author of and was referenced by Dr. Lindsay in his deposition. See **Goodnight Exhibit B-43** Tr. 167:11-12; 175:16-18. The data presented in this paper contradict the claimed chemical fingerprint of the three-water sources. Table 2, found on page 181/13, provides a comprehensive water chemistry analysis for the EMSU 461, a water supply well producing from the San Andres. This table shows that EMSU 461 has a TDS value of 21,385 ppm (significantly different from the Gulf Oil test discussed above). The Grayburg producers listed in the same table exhibit TDS values ranging from 5,649 to 35,030 ppm. These tests were taken 5 years after water injection began but we believe the Grayburg samples are still representative and are valid. The water supply well measurement would not be affected by the date the water flood began. None of the measurements we have in our possession agree with the assertions that Dr. Lindsay uses for his three-water chemistry. Dr.

Lindsay did acknowledge he has not attempted to independently corroborate his chemical definitions for these three-waters and confirmed that he has not reviewed any chemistry data. See **Goodnight Exhibit B-43** Tr. 169:18-22.

27. The chemistry of the water in the San Andres can have a range of values. The range of values recovered in tests can be from about 7,000 TDS[1] to well over 200,000 TDS, but the bulk average is about 30,000 ppm. Goodnight believes that the use of highly variable water chemistry to prove damaging communication between the Grayburg oil reservoir and the San Andres water management reservoir is invalid. There are other more reliable data that show the barrier between these two reservoirs is competent and durable through time. Good confinement of the San Andres disposal zone exists and it is safe to proceed.

Claims that there is not a Pressure Differential Between the Producing Grayburg and the San Andres Disposal Zone

28. Data provided to Goodnight from Empire further confirms that there is a pressure differential between the Grayburg and San Andres that is sustained across the field. **Goodnight Exhibit B-45** is a spreadsheet that was provided to Goodnight in response to a subpoena where Goodnight was requesting the shut-in pressures for Empire's EOR injection wells in the Grayburg (OCD 23614-17 03623 EMSU Injection Wells_202402 Minimums.xls). The spreadsheet has only been modified to remove wells that did not have data or had notes from Empire stating there were data issues with the well. The highlighted column is labeled as "min_SIP_reviewed". Goodnight understands this to mean that Empire has reviewed the data and confirmed them as being a valid minimum shut-in pressure (SIP) for the wells listed. The data shows that the reviewed shut-in pressures for the wells listed have an average pressure of 524 PSI. As discussed in my direct

[1] There are only two samples that have TDS less than 10,000 ppm in 30 townships that have been reviewed.

testimony, the shut-in pressures for the EOR injectors in the Grayburg are significantly different than the all the SWDs in the EMSU which shut-in with negative wellhead pressures. See Goodnight Exhibits B-11, B-12, B-21, B-22, and B-23 (McGuire direct testimony). This data further confirms the pressure differential between the Grayburg producing interval and the San Andres disposal interval indicating that there is an effective and competent barrier between these zones.

REBUTTAL TO CLAIMS OF A ROZ IN THE WATER SUPPLY/DISPOSAL ZONE

29. Empire has not shown any data that confirms that there is a ROZ within the San Andres disposal zone utilized by SWD operators within the EMSU. Below is a summary of my rebuttal points.

- The claimed ROZ in the San Andres disposal zone has been tested using a production method that has been described by Empire's witness called DUROZ. The water supply wells in the fields produced more than enough volume to develop a gas drive that should have produced some oil if there was oil to be recovered.
- Dr. Lindsay and Dr. Trentham were unaware of the long history of disposal that has been occurring in the EMSU, and therefore could not speak to how this history could have affected the claimed ROZ in the disposal zone.
- Dr. Lindsay and Dr. Trentham both state that the cutoff for oil saturations, which define a ROZ is 20%. Dr. Trentham agrees with where Goodnight placed the base of the ROZ in Goodnight Exhibit B-32.

30. The disposal zone has been tested over nearly two decades using a production method described by Dr. Trentham in his testimony called de-pressuring a residual oil zone (DUROZ). Below is an excerpt from his testimony on page 22 describing this production method:

Depressuring the Residual Oil Zone – DUROZ

> Platang Field in southwestern Yoakum County, TX is an example of a DUROZ production method, Depressuring the Upper Residual Oil Zone, that does not use CO2. The method employs horizontal wells land high in the ROZ/Oil Column that cannot be economically produced with vertical wells. Initially, the operator will use submersible pumps to produce 500 – 2,000 barrels of fluid a day. Often the well is pumped for 30 to 60 days before the first oil is produced. The drop in pressure associated with the high volumes of water produced would result in swelling the oil and the development of a solution gas drive. Since the only way to produce economic volumes of oil is by reducing the pressure. Platang Field total Production >72,000,000 BO since 2006.

31. This production method was effectively enacted by the EMSU water supply wells that were used for make-up water to flood the Grayburg. These wells produced more than 20,000 BWPD for 18 years, from late 1986 through the middle of 2004 as shown in Empire Exhibit E-4. A peak extraction rate of 100,000 BWPD was reached for the year 1996. The 11-year period from 1987 to 1998 averaged a produced water rate of more than 60,000 BWPD. This is magnitudes more volume than what is described as needed to test a ROZ. Trentham set the threshold at 500 to 2,000 BWPD. Trentham also states that the wells at the Platang Field were pumped 30 to 60 days before the first oil was produced. In contrast, the EMSU water supply wells were produced for more than 4000 days at a high rate and no oil was ever produced. This is a definitive test of the claimed ROZ in the San Andres water supply/water disposal zone. Further testing of the water disposal/supply interval is not warranted.

32. Dr. Lindsay and Dr. Trentham both described the de-pressuring of the ROZ concept as a valid production method in their depositions. **Goodnight Exhibit B-43** and **Goodnight Exhibit B-39** include excerpts from their deposition transcripts. Dr. Lindsay describes needing to pump off tens of thousands of barrels to drop the pressure in the reservoir and produce the ROZ. **Goodnight Exhibit B-43** Tr. 134:22-135:20; 140:13-141:5. **Dr. Trentham explained that he**

would have expected the EMSU water supply wells to produce some oil if the water supply/disposal zone was a ROZ given the volumes extracted. Goodnight Exhibit B-39 Tr. 143:13-145:22; 147:9-24.

33. The water supply wells significantly dropped the pressure within the San Andres due to the very large volumes of water produced. This pressure drop is significant enough to swell oil and develop a solution gas drive that should have produced oil if there was oil in the intervals to be produced. The water supply and water disposal occur in the same zone at EMSU that all operators, including Goodnight, utilize as the water management interval. **The fact that these water supply wells never reported a single barrel of oil proves that there is not a ROZ within this water management interval as they tested the interval with an accepted ROZ development method as put forth by Empire's own witnesses.**

34. Both Dr. Lindsay and Dr. Trentham acknowledged that they did not evaluate the water supply wells at the EMSU. See **Goodnight Exhibit B-43** (Dr. Lindsay) Tr. 108:11-112:10; **Goodnight Exhibit B-39** (Dr. Trantham) Tr. 67:4-68:19; 73:19-74:3; 121:3-13. Remarkably, they had not been informed by Empire of the location of the water supply wells, what zone they were completed in, or how much water they produced. They confirmed that they did not review or take into consideration the water supply wells or the effect they would have on the claimed ROZ in this interval. XTO was optimistic when pointing out the future potential of the ROZ in the sales materials presented to Empire yet it seems the history of the water supply wells was not part of the story. Also, Empire is well aware of this water management zone and chose not to inform their ROZ experts.

35. In addition, neither Dr. Lindsay nor Dr. Trentham were aware that the San Andres has been used as a disposal zone since the 1960s in and around the EMSU. They also did not

realize that Empire itself has a disposal well in the San Andres within the Unit. See **Goodnight Exhibit B-43** (Dr. Lindsay) Tr. 135:20-136:11; 137:15-139:9; 217:9-218:6; **Goodnight Exhibit B-39** (Dr. Trantham) Tr. 116:17-23; 121:19-122:4. Because they were unaware of these disposal wells, they were unable to speak to how this historical disposal could have impacted the claimed ROZ in the disposal zone long before Goodnight began its disposal operations.

36. Finally, both Dr. Lindsay and Dr. Trantham confirmed that 20% oil saturation is the threshold for defining a ROZ. See **Goodnight Exhibit B-43** (Dr. Lindsay) Tr. 104:18-105:8, 106:9-19; 143:20-144:4; **Goodnight Exhibit B-39** (Dr. Trantham) Tr.126:7-15; 128:5-12; 129:6-18; 140:13-25; **151:13-155:16**. Dr. Lindsay also confirms that oil saturations above 20% are only potentially commercial. Separate from the San Andres disposal zone, **Dr. Trantham agreed with where Goodnight put the base of a potential ROZ in the lower Grayburg, based on the EMSU 679 core data and a 20% oil saturation cutoff when reviewing Goodnight Exhibit B-32. Goodnight Exhibit B-39 Tr. 151:13-155:16.**

37. The claimed ROZ within the disposal interval of the San Andres has effectively and definitively been tested using a production method described by Empire's experts. The water supply wells in the field should have produced some oil if there was oil to be produced from that zone due to the drop in pressure from the massive amounts of water that was produced. Dr. Lindsay and Dr. Trantham were both unaware of the long history of disposal operations that have occurred in the EMSU and cannot speak to how that disposal could have affected the claimed ROZ. They also confirmed that the oil saturation for a ROZ is 20%. Dr. Trantham agrees with Goodnight that the base of the ROZ is well above the top of the disposal interval utilized by Goodnight and other SWD operators.

Buchwalter Model Rebuttal

38. The reservoir simulation model that Empire and Dr. Buchwalter has put forth in these cases does not accurately represent reality and is missing key details which, taken together, strongly indicate that it was designed to provide a predetermined answer. Below is a summary of my rebuttal points to Dr. Buchwalter's reservoir modeling.

- The model does not incorporate all the San Andres water supply wells that are in and around the EMSU, EMSU-B, and the AGU, nor the volumes of water that these other water supply wells produced.
- The model does not include all the San Andres SWDs that are in and around the three units or the volumes that were disposed into these SWDs. The model is also missing decades of data for the volumes injected in some of the wells that were included in the model.
- Dr. Buchwalter's model excludes edge water from the Goat Seep Aquifer into the Grayburg producing zone as explained by other Empire experts and documented throughout the literature analyzing the EMSU.
- Dr. Buchwalter did not incorporate accurate perforations or the mechanical changes made to producing wells in the three units over time and therefore cannot accurately model the production history of the wells.
- The model does not accurately reflect the geologic reservoir complexities inherent in complex carbonate ramp systems that other Empire witnesses have discussed.

39. Dr. Buchwalter's model is missing at least 18 San Andres water supply wells in the area of the Empire units. **Goodnight Exhibit B-19** in my direct testimony is a map showing the San Andres water supply wells that have been identified by Goodnight while researching the area

around the Empire units. The dots on the map identify the locations of the water supply wells and their status as of April 2024. **Dr. Buchwalter included only the six water supply wells inside the EMSU and the two wells inside the AGU but did not include the other 18 wells shown on the map.** While many of the water production records for these wells are incomplete, using water data that is available, **Goodnight has estimated the cumulative water production volume from these wells to be more than 850 million barrels of water and could be as high as 1.0 billion barrels.**

40. **Goodnight Exhibit B-46** is a table showing all of the water supply wells that are posted in Goodnight Exhibit B-19. The table shows the API number, well name, NMOSE Point of Diversion (POD) number, cumulative water produced, and the source of the water volume data. Wells with the source listed as "OCD" had complete production volumes available in OCD records. Wells labeled with "Reconstructed from well tests" had their volumes estimated by taking the tested daily production rate that was identified in the well files and multiplying it by the number of days the well was active. This is justified because the wells that had a full history of production volumes never saw a decline in the amount of water they could produce over time and were unable to deplete the reservoir. Some wells had partial volumes that were available through OCD records but had to be supplemented with reconstructed volumes from well tests as they began production before the OCD records started. One well did not have any publicly available production volumes or well tests. In that case the unitization documents were reviewed for the unit that well was associated with. The unit documents identified the estimated make-up water volume that was needed to enact the waterflood and that was used as the estimated volume that was produced from that well. There was only one well where there were no documents identified that could be used to estimate the produced volumes.

41. **The table shows that 852 MMBW have been produced from the San Andres in the area around the three Empire units.** This table likely underestimates the volumes of water that was produced from the San Andres as we are missing data on one well and other wells had the ability to produce at higher rates than was tested given offset tests in other water supply wells. **Only a fraction of this volume was incorporated into Dr. Buchwalter's model and therefore the model cannot possibly accurately simulate the reservoir dynamics of the San Andres in this area.**

42. Dr. Buchwalter's model also does not incorporate all the San Andres SWDs that are in and around the Empire units. **Goodnight Exhibit B-47** is a map showing all of the SWDs that are withing five miles of the Empire units (black dotted line shows a five mile buffer around the three units). This distance was chosen as the offset as Dr. Buchwalter claims that there should be no produced water disposal in the San Andres within five miles of the units.[2] The wells are color coded by operator and the shape of the symbol depicts its status (active=triangle, plugged=circle, or pending=square). The first injection date and cumulative injected volumes are posted with each well. Some wells were plugged before OCD records of injection volumes began and no disposal volumes have been identified for those wells. These wells have been tagged with "Cum Unk bbls" on the map. Other wells had incomplete volumes from OCD records, these wells have their cumulative injected volumes tagged with "> XXX bbls" as they are missing data for the cumulative barrels they have disposed of. When comparing this map to Dr. Buchwalter's Exhibit E-1, it is apparent how many SWDs were ignored in Dr. Buchwalter's modeling efforts. Strangely, he did not incorporate Empire's own EMSU SWD within the model. **To have an**

[2] Mr. West testified in his direct testimony that no injection should be allowed within two miles of the units and potentially up to five miles with approval of "all unit holders." See Exhibit I-6.

accurate model, one must incorporate all the data for the area that is being modeled. Dr Buchwalter states that all the data from the beginning of operations needs to be incorporated to have the most accurate model possible including the SWDs. See **Goodnight Exhibit B-52** Tr. 23:1-7; 62:16-21; 97:14-98:15.

43. Dr. Buchwalter's model is not only missing many SWDs, but he is also not incorporating all the volumes that have been disposed of into the wells he is modeling. As shown by Goodnight Exhibit B-47, the date of first injection of the SWDs is included with many of the first injection dates being pre-1994. This is critical as Dr. Buchwalter only modeled the SWD volumes from 1994 onwards as shown by Empire Exhibit E-5. Many of the Rice SWDs that he did include in his model commenced injection operations into the San Andres as early as the 1950s and 1960s and had disposed of tens of millions of barrels as of 1994. **This means he is missing 30 to 40 years of injection volumes in his model from those wells alone. It is not possible for Dr. Buchwalter to have an accurate reservoir model when he is missing hundreds of millions of disposal volumes from the wells he did model and the wells he did not incorporate into the model at all.**

44. Dr. Buchwalter states the following on page two of his written testimony about the model and his justification for allowing the San Andres to communicate with the Grayburg:

> One of the most significant findings of the study was that water production from wells in the central portions of the field at EMSU and AGU could not be matched without allowing some water to migrate from the San Andres to Grayburg by adjusting the vertical permeability between zones. Without adjusting the vertical permeability of layer 8 (top of San Andres) and allowing water to move into the Grayburg, there were over 100 wells in the central portions of EMSU and AGU which produced very limited amounts of water when there was no communication between zones. By adjusting the vertical permeability based on historical production performance, a fieldwide match was obtained both on production and pressures.

45. In fact, Dr. Buchwalter was not able to obtain a history match to the water production volumes even in his model that allowed for communication from the San Andres. See Empire Exhibits E-12a, E-13a, E-14a, E-15a, E-16a, E-17a, and E-21a-p. The water production graphs in these figures show that his model does not match the production history of the wells as shown by the difference in the modeled curve in blue and the production history in black. The model simply does not match the water production history on a well-by-well basis.

46. Additionally, the examples given for the model run where he did not allow for San Andres communication has a major problem. **As shown in Empire Exhibits E-12b, E-13b, E-14b, E-15b, E-16b, and E-17b the modeled water production rates for these wells showed no water production, flat water production, or a decline in water production during the waterflooding period that began in 1986. This model result makes no sense for a unit that was on active waterflood. This shows that he is starting with a poor model and that nearly all the modeled water production in these examples is from the San Andres with none of it being from the waterflood. This is a critical error and shows that the modeling efforts severely miss the mark of accurately modeling the waterflood.**

47. There are three key details that Dr. Buchwalter excluded from his model that would have allowed him to obtain a water production history match for the Grayburg wells without allowing for communication from the San Andres. First, Dr. Buchwalter did not include the perforations or the mechanical changes that were made to the Grayburg production and injection wells over time in his model. He stated in his deposition that he just assumed that all the wells were perforated in the oil column above -366 subsea, which is the initial oil-water-contact (OWC) he used. This is simply not the case and fails to match reality as many of the wells had perforations much deeper than -366. **Goodnight Exhibit B-48** shows the list of wells where Dr. Buchwalter

allowed communication from the San Andres. The table shows the API number, well name and number, the deepest completed interval that was ever open in the well in measured depth, and the same depth converted to a subsea value. As shown in red, 20 of the wells (40%) had completions below the -366 subsea OWC that Dr. Buchwalter used and 32 of the wells (64%) had completions below the -325 subsea OWC described in the unit documents (wells highlighted in yellow have completions deeper than -325 but shallower than -366). Because many of these wells had completions below Dr. Buchwalter's OWC this could explain why he could not get a match to the water production volumes as he just assumed that none of the wells were ever open below the OWC. **He likely did not need to allow San Andres communication in these wells to match the water production history if he would have included the completion histories of these wells.** For the wells that were never open below the OWC, their water production histories can be explained by the other points made below.

48. Additionally, many of the EMSU wells were historically comingled with the overlying Eumont gas pool in the Penrose. **Goodnight Exhibit B-49** is a map that was presented in the original cases to unitize the EMSU as Exhibit 23 in Case No. 8377. The 130 highlighted wells historically had completion intervals that overlapped in both the Eumont and Eunice Monument pools. Blue wells were classified as being in the Eumont Pool while green were assigned to the Eunice Monument Pool at the time of the unitization hearing. These highlighted wells have an indication posted of how many feet are exposed in each of the comingled wells, the upper number being the feet exposed in the Eumont Pool and the lower number being the number of feet exposed in the Eunice Monument Pool. For a model to be accurate in matching production, the history of these comingled wells must be considered.

49. Second, Dr. Buchwalter did not incorporate key reservoir aspects that Empire's other witnesses testified to, particularly the edge water drive from the Goat Seep Aquifer into the Grayburg producing zone—especially the lower-most Grayburg zones. Dr. Lindsay testified that there was an edge water encroachment into the Grayburg producing zone from the west as shown in Empire Exhibits B-21 and B-27. Dr. Buchwalter was clearly unaware of Dr. Lindsay's work on the field. This is of critical importance because Dr. Buchwalter states in his testimony that he could not get a history match to the water production volumes in the Grayburg producing wells without allowing for the San Andres to communicate with the Grayburg producing wells and that was his justification to allow the San Andres to communicate with the Grayburg in his model. **It is possible that he would have been able to get a much closer match to the water production volumes in the model run where he did not artificially allow for the San Andres to communicate with the Grayburg if he were to have simply incorporated the Goat Seep edge water into his model which could account for missing water production volumes in his first model run. Dr. Lindsay testified in his deposition that no reservoir model could be accurate for the EMSU if the Goat Seep edge water was not incorporated.** See **Goodnight Exhibit B-43** Tr. 222:2-19.

50. During a March 2000 contested hearing (Case No. 12320) Chevron, who was the operator of the EMSU at that time, was seeking to increase the maximum surface injection pressure for several of the EMSU EOR injection wells. During the hearing Mr. Tracy Love, a petroleum engineer for Chevron, testified that Chevron had identified water that was unaccounted for that was being produced in the field. **Goodnight Exhibit B-50** is an excerpt from the transcript of the hearing of Mr. Love's testimony. See Tr. 47:22-50:3. He stated that the water that was unaccounted for was due to encroachment of edge water from the west. This edge water that Mr. Love is referring to is sourced from the Goat Seep Aquifer as discussed by Dr. Lindsay. **There is no**

discussion that San Andres is communicating with the Grayburg and providing any water that is unaccounted for to the field. Dr. Lindsay testified in his deposition that it was "common knowledge" at Chevron that the San Andres was high in sulfates and was migrating through fractures into the Grayburg through "plumes" resulting in wells with high water production and that it was "common knowledge" to Tracy Love, too. Dr. Lindsay also testified that Chevron never mapped the so-called San Andres "plumes," but that Tracy Love did prepare maps of high-water cut wells and published a 1998 SPE paper on them. See **Goodnight Exhibit B-43** Tr. 173:7-174:18. However, there is no data or documentation corroborating Dr. Lindsay's recollections or his assertions that it was "common knowledge" or that there ever were "plumes" of San Andres water migrating into the Grayburg. All we have is Tracy Love's SPE paper and his testimony to the Division in Case No. 12320. **When asked about it at hearing in 2000, Tracy Love identified only edge water and water cycling through high-permeability streaks as the only sources of unaccounted for water in the EMSU—not San Andres water.** And his 1998 SPE paper also does not identify San Andres water as migrating into the Grayburg. See **Goodnight Exhibit B-51.**

51. Mr. Love also stated in his testimony that Chevron had done a full field simulation on the EMSU. Given the fact that Mr. Love was directly asked about unaccounted water in the EMSU and did not identify the San Andres as contributing water to Grayburg production strongly suggests that Chevron did not believe this to be true and did not have that incorporated into their simulation. If they did believe this and had it incorporated into their reservoir simulation, why would he not mention it when directly asked?

52. Dr. Buchwalter struggled to obtain a history match to the water production in the EMSU producers because he was missing key details of the Grayburg reservoir edge water and the mechanical configurations of the wells. It is possible that he could have been able to get a

history match to the water production without allowing the San Andres to communicate with Grayburg if he had incorporated these details. **Because he did not model the Goat Seep edge water or the wells that had perforations below his OWC of -366, he was not able to match the water production history of the wells and decided to artificially allow for communication from the San Andres which would not have been necessary if the discussed details were included in the model.**

53. Third, it does not appear that Dr. Buchwalter understands the geology he is trying to model and has not incorporated how complex the Grayburg reservoir is at EMSU. First, during Dr. Buchwalter's deposition he frequently referred to the two reservoirs as "sands". The Grayburg and San Andres are carbonate reservoirs with very little sand content. **Goodnight Exhibit B-52** are excerpts from Dr. Buchwalter's deposition where he consistently referred to the reservoirs as "sands." See Tr. 74:10; 113:6; 125:17; 127:14; 170:2; 175:12; 211:7; 216:14; 246:18; 255:12. This goes to show that Dr. Buchwalter does not appear to understand the system he is trying to model or at least has not taken the time to incorporate the well-documented complexity of the carbonate system into his simulation.

54. In his deposition, Dr. Lindsay discussed the complexities of the Grayburg reservoir. He referenced Empire Exhibit B-5, which illustrates the intricate geology of the Grayburg carbonate system across the field, and emphasized the need to incorporate this complexity for an accurate reservoir simulation. See **Goodnight Exhibit B-43** Tr. 144:9-145:15.

55. Dr. Buchwalter did not incorporate a detailed static geologic model with the level of detail needed to accurately model the flow dynamics of these intricate and complex reservoirs. From reviewing Dr. Lindsay's exhibits, particularly Exhibits B-5, B-28, and B-30, one can see how complex the Grayburg reservoir is due to reservoir heterogeneity, facies changes, and

stratigraphic relationships of a carbonate ramp system. Dr. Buchwalter used a single porosity and permeability value for each of his layers in the model. Dr. Lindsay shows that there is large variation in porosity and permeability within individual layers which Dr. Buchwalter did not incorporate in the model. It is necessary to build a geologic model that incorporates petrophysical log data and core data on a well-by-well basis such that the reservoir model includes the complex variability of the reservoir across the field. These complexities are the reasons that EMSU had conformance issues from the initiation of the waterflood. Mr. Love highlighted some of these conformance issues in his testimony shown in **Goodnight Exhibit B-50** that was discussed earlier in my testimony. Mr. Love described the following about conformance issues relating to the EMSU waterflood.

> [W]e produce most everything we inject . . . Except for the start of the flood before the water broke though in some of those high-permeability streaks. We have a real bad problem with cycling water through those high-permeability streaks. They're like pipelines, and until those broke through we were – you know, water production was lower. But once the injection broke though, you're almost at one with your water in, water out, till you squeeze out of those high-permeability streaks.

Goodnight Exhibit B-50 Tr. 48:16-24.

56. Chevron and XTO, the previous operators of the fields, had undertaken a lot of conformance work by deepening wells, squeezing perforations, and adding perforations to help the waterflood become more efficient and to address the issues that Mr. Love described above. To have an accurate reservoir simulation model that matches the production history of the field, it is critical to incorporate the well conformance work and the geologic complexity of the reservoirs. It is possible that Dr. Buchwalter would have been able to match the water production rates in his model run that did not allow for San Andres communication if he were to include these reservoir complexities, like the high permeability streaks that allowed water to break through very quickly.

57. Dr. Buchwalter missed the mark of building a reservoir model that accurately reflects the reality of how the EMSU and the other Empire fields actually operated and produced by missing key details. Because of the reasons discussed above, the model he has presented does not reliably reflect water production in the EMSU and cannot be used to support a conclusion that the San Andres is communicating with the Grayburg. Dr. Buchwalter appears to have been biased by Empire's initial assumption that there is communication from the San Andres into the Grayburg and, therefore, produced a model that gave Empire the answer they were looking for without taking into consideration all the facts. He was also at a disadvantage because he was entirely reliant on the information and data provided to him by Empire. They did not provide him the key missing information and he did not do an independent investigation to determine what might be missing from his model. See, e.g., **Goodnight Exhibit B-52** Tr. 97:25-98:2.

Response to OCD Concerns

58. The OCD raises concerns about potential communication between the San Andres disposal interval and the Capitan Reef. Those concerns are unfounded. Despite the absence of new data or justification, the OCD has elevated its concerns on this issue after more than a 60-year history of San Andres disposal occurring in the Hobbs Channel. Below is a summary of my response points.

- Goodnight has always engaged with the OCD relating to questions about the Capitan Reef in prior application and hearings. The OCD has already approved 12 Goodnight San Andres SWD permits. There is no clear justification for the OCD's newly elevated concerns.
- The OCD's concerns stem largely from 1970s research by Dr. William Hiss. His research assumed that the San Andres was stratigraphically connected to the

Capitan Reef. Peer-reviewed research and modern stratigraphic models confirm that the San Andres is not in stratigraphic or hydraulic communication with the Capitan Reef.

- The work by Dr. Hiss needs to be updated and quality controlled. Goodnight has performed this work for the San Andres data in the area of the Hobbs Channel.
- The updated a corrected water chemistry data shows that Hobbs Channel (Outflow) is limited to the Artesia Group, above the San Andres, where there is a known stratigraphic and hydraulic connection with the Capitan Reef.
- Available water quality data shows that the Capitan Reef within the investigated area does not meet the standards for USDW quality water.

59. Goodnight has always been aware of the Capitan Reef and its status as a currently protected aquifer. Contrary to OCD's testimony, Goodnight has addressed the concerns raised by the OCD about potential impacts on the Capitan Reef numerous times in our previous application hearings, and in response to the Division's follow-up questions. The OCD has posed questions in the permitting phase and at hearings on these previous applications, asking Goodnight if we have considered the Capitan Reef Aquifer, investigated its proximity, and evaluated any impact. We state in each application that we do not impact any USDW including the Capitan Reef.

60. **Goodnight Exhibit B-53** is a combination of hearing transcripts and an email in which Goodnight answered questions relating to the disposal operations relative to the Capitan Reef, showing that Goodnight has always been engaged with the OCD on this issue and has answered any questions that have been raised. Also attached in the exhibit are hearing orders in which the OCD acknowledged the discussions about the Capitan Reef. Goodnight has received approval from the OCD for 12 San Andres permits in the EMSU area, which has a long history of

San Andres disposal operations going back to the 1950s and 1960s. **Until now, Goodnight had understood it had resolved OCD's concerns because OCD did not have any additional follow-up questions or concerns and approved all of Goodnight's previous SWD applications.** It is not clear what, if anything, has changed since these prior applications that has elevated their concerns and broadened their area of investigation well beyond previous inquiries.

61. In these cases, Goodnight is now being asked to comment on the disposal operations of many different operators, some occurring before our injection began, and with absent or incomplete records for those disposal operations. The OCD testimony does not provide any new data that would show a reason to have a change in opinion on San Andres disposal in this area after already approving 12 Goodnight permits and many others dating back 60 years.

62. In 2020, the OCD provided a letter to the EPA titled *Update of Underground Injection Control Class II Activities with the State of New Mexico for Possible Injection into Underground Sources of Drinking Water: The Capitan Reef Aquifer System* and was included in the OCD testimony as OCD Exhibit 10. The letter included a list of 32 injection wells which the OCD determined required additional investigation to determine if they were causing potential impacts to the Capitan Reef and evaluate the potential or necessity for establishing exempt aquifer status. The list is included in OCD Exhibit 10, Table 1 on page 13. All the wells listed are injecting into the Artesia Group—comprised of the Grayburg, Queen, Seven Rivers, Yates and Tansill formations—while no San Andres wells are listed. This highlights that OCD's concern with San Andres disposal appears to be only a recent development, yet no new information has come to light following submission of this letter to the EPA to indicate the reason for the newly elevated concern.

63. The OCD appears to be heavily depending on the work of Dr. William Hiss for the basis of their concern that the San Andres may be in hydraulic communication with the Capitan Reef. Dr. Hiss aggregated thousands of produced water chemistry samples for the Permian Basin in the mid-1970s and developed the first database of this kind. This work was instrumental in developing an understanding of the water chemistry of various formations in the Permian Basin. Dr. Hiss used this data to publish a map titled *Chloride-Ion Concentration in Ground Water in Permian Guadalupian Rocks, Southeast New Mexico and West Texas*. This work, while contributing to the scientific understanding of the shelf-to-basin hydrology, needs to be updated and has data quality control issues.

64. The Hiss map was used to define an area he called the "Hobbs Channel" and is included as **Goodnight Exhibit B-54**. The map includes datapoints and contours of chloride concentrations from various Guadalupian aged formations (Hiss put the data from all geologic depths on one map) and a shaded area showing the limits of the Capitan Reef. Hiss described the "Hobbs Channel" as an area with less than 10,000 ppm chloride concentration, (which equates to ~20,000 TDS). **Goodnight Exhibit B-54** shows the area of low chloride concentration defined by Hiss by overlaying the red contours that are shown on OCD Exhibit 2, which show Hobbs Channel. Dr. Hiss postulated that the permeable facies of the Capitan Reef had the ability to flow into the Guadalupian-aged back reef and shelf formations in the geologic past. His assumption is that would have dropped the chloride (and TDS) concentration in those shelf formations. Dr. Hiss included the San Andres in the group that is connected to the Capitan Reef.

65. Dr. Hiss was working under the stratigraphic framework as it was thought to be at the time he published his work in the 1970s. **Goodnight Exhibit B-55** shows a cross-section of the shelf-to-basin stratigraphy as it was understood at the time of his publications. The image is

copied from his chloride-ion concentration map and has been enlarged. In it, Dr. Hiss shows that he believes the San Andres is laterally connected to the "Capitan Aquifer." That interpretation has changed. **Current investigators and publications demonstrate the updated and corrected stratigraphic model, accepted by academic institutions and peer reviewed in publication, showing that the San Andres is not laterally connected to the Capitan Aquifer.** Dr. Hiss was working under the stratigraphic relationships as they were understood at the time when he was publishing this work. Updated publications show that this stratigraphic understanding was not correct.

66. Goodnight has presented valid peer reviewed data that has appeared in scientific publications that the San Andres is not connected to the Capitan Reef either directly or indirectly through the Goat Seep. The Capitan Aquifer and the San Andres are different stratigraphic ages and are not in communication. This can be seen in Goodnight Exhibit B-29 showing the most up-to-date stratigraphic model for the shelf-to-basin stratigraphic relationships and shows that the San Andres is never in contact with the Goat Seep or the Capitan.

67. Further, Goodnight's own investigation shows this same relationship with a cross-section from the EMSU, through the shelf margin, and into the basin. Page one of **Goodnight Exhibit B-56** is a cross-section index map showing the path of the cross-section in black and the wells used are indicated by red dots. The map also includes the unit boundaries of the three Empire units, EMSU, EMSU-B, and AGU. The purple polygon is the Capitan Reef boundary from a 2009 Texas Water Development Board publication and is the most recent and accepted Capitan Reef boundary. The red lines are the boundary of the "Hobbs Channel" as defined by the OCD exhibit. We add them for geographic reference. The goal of the cross-section is to show the stratigraphic relationships of the shelf-to-basin facies in the disposal area by taking a dip-oriented cross-section

path and using wells that were approximately one mile apart along the path that had log coverage across the Capitan Formation. The next page shows the cross-section with the Central Basin Platform shelf being on the right and the Delaware Basin on the left. Blue shading on the figure shows the Capitan and Goat Seep Reefs, green shading is the Grayburg interfingering with the Goat Seep, and purple shading is the San Andres interfingering down dip into the Cherry Canyon Member of the Delaware Mountain Group. As shown by the purple shading, the San Andres is never in contact with the Goat Seep or the Capitan Reefs and is significantly deeper. Given the fact that there is a competent barrier at the top of the San Andres, there is a very low probability that the disposal water could migrate out of zone up into the Goat Seep. It is even more improbable that disposal fluids in the San Andres could make migrate into the Capitan Reef given the significant vertical separation between the formations. Additionally, given the nature of the San Andres being deposited on a shelf slope with a rapidly increasing water depth to the west, the San Andres porosity diminishes very quickly just west of EMSU. This is due to a finer grained material (mud dominated) being deposited in the deeper water which has little to no porosity, as opposed to the shallower water environment at EMSU which allowed for porosity development. This lack of porosity can be seen in the down dip purple shaded section that interfinger with the Cherry Canyon. These carbonates have very little if any porosity on a log. Rapid deepening along the western margin of the Central Basin Platform further separated San Andres tallis slope fans from the Goat Seep Reef that was deposited above. **There is no pathway for water to migrate from Goodnight's San Andres disposal zone to the Goat Seep. Further, there is no pathway for water to migrate to the Capitan Reef.**

68. The San Andres is not connected to the Capitan or its back reef facies. The San Andres data should not have been included on the Hiss chloride-ion concentration map, at

least for the purpose of drawing hydraulic communication conclusion with the Capitan Reef. It is not in hydraulic communication with the Capitan Reef. Next, the Hiss map contours do not match the data points posted, particularly in the Hobbs Channel. The contours were drawn in a search for, and the highlighting of, any low values found while ignoring contrarian data in the same space. He gave no weight to the preponderance of the data but simply found and highlighted low values. Dr. Hiss explains this in the legend of the map stating that the contours represent the following:

> Lines of equal chloride-ion concentration, in thousands of milligrams per liter. Dashed where inferred. **Based on the lowest concentration shown or interpreted to be present.** Within any area delineated by two lines, ground water having a chloride-ion concentration indicated by the line values is probably present in at least one water-bearing zone; ground water having a higher chloride-ion concentration than that indicated by the contour values is generally present also.

69. The Hobbs Channel only exists in the Artesia group. The hydrodynamic connection between the reef and the back reef facies is shown in **<u>Goodnight Exhibit B-57</u>**. This map shows the TDS values of waters within the Artesia Group from multiple different public datasets. The additional data shows that there is room for improvement in the shape of the Hiss contours but there is an indication that the Reef moved water into the back reef facies of the Artesia Group at times during geologic history in the area defined as the Hobbs Channel (shown with the red lines). Dr. Lindsay confirmed this connection and describes edge water from the Reef entering the Grayburg at the EMSU. The outflow from the Reef coincides with the point where the reef system comes in close proximity to the Central Basin Platform shelf edge. The outflow occurs at the point where the permeable reef and high energy shelf carbonates are no longer separated by low permeability lagoonal facies. This allows for communication along the trend for water to escape the hydraulic head following the lower gradient pathway to the northeast. However, this

pathway—which is geologically bound—only exists in the Artesia Group. San Andres is not part of, nor does it participate in, this inter-reservoir exchange.

70. The Hobbs Channel is an offramp connection to the San Simon Channel freeway in the Artesia Group. The San Simon Channel feature is a structural low created by fault slip movement between the north end of the Central Basin Platform and the Northwest Shelf. It connected the Delaware Basin to the Midland Basin during Leonardian time. The lithology of the Guadalupian formations inside the San Simon Channel is different from the shelf rocks on either side of it. The San Simon channel has a much higher siliciclastic content, sediments equivalent to the Delaware Mountain Group filled the channel. **Goodnight Exhibit B-58** is a structure map on the top of San Andres formation utilizing publicly available tops that was aggregated by IHS. This structure map shows the structural low of the San Simon Channel that separates the Central Basin Platform from the Northwest Shelf.

71. The OCD's Primacy Agreement for the OCD's UIC Program does discuss the Hobbs Channel in OCD Exhibit 4. This document gives a **geologic** description of the Hobbs Channel as follows:

> A major paleogeographic feature of the area is known as the Hobbs Channel (Figure 8). This channel was a bathymetric low in the Permian and connected the Delaware and Midland Basins on the northern end of the Central Basin Platform.

72. The OCD Primacy Agreement is clearly describing the San Simon Channel, a geologic feature of tectonic origin but called it "Hobbs." **Goodnight Exhibit B-59** is Figure 8 from OCD's Primacy Agreement Appendix II (OCD Exhibit 4). The map shows how the Primacy Agreement defines the Hobbs Channel's geographic extent. The map has been overlain with the Hiss definition of the Hobbs Channel from the chloride-ion contours (from OCD Exhibit 2) in red and the boundary of the San Simon Channel in brown. At this point, it appears that the OCD has

three partially conflicting definitions for the geographic location of the "Hobbs Channel" as shown in Exhibit B-58. Our work has brought clarity to these discrepancies. See Goodnight Exhibit B-56. The San Simon Channel and the Hobbs Channel are separate features with the Hobbs Channel acting as a hydrodynamic conduit to the San Simon Channel at the Artesia Group level. The Hobbs Channel only interacts with rocks within the Artesia Group. To clarify the distinction between Hobbs Channel and the San Simon Channel, it is recommended to rename Hobbs Channel to the 'Hobbs Outflow,' as it is hydrodynamic in nature rather than a geological channel.

73. Having established that there is no geologic connection between the San Andres and Capitan Reef, and that the hydrodynamic feature observed at the Hobbs Outflow is limited to the Artesia Group, Goodnight wanted to understand the basis for Hiss's conclusion that a geochemical signal connected the San Andres to the Capitan.

74. To do that Goodnight investigated all the San Andres datapoints on the Hiss chloride concentration map in the Hobbs Outflow (as defined by OCD Exhibit 2). Goodnight obtained the supporting database[3] that Hiss used to build the chloride-ion concentration map. This publication was a data aggregation effort by Dr. Hiss of produced water chemistry. The database does not identify the well that was sampled. It does have the section township and range along with the date the sample was taken, the depth, the assigned formation name, and the chemistry analysis of the water. Goodnight used the Chloride Ion map to further define the location within a section. This could get the area down to plus or minus 2000 feet around the posted value on the map.

[3] Hiss, W.L., 1975, Water-quality data from oil and gas wells in part of the Permian Basin, southeastern New Mexico and western Texas (No. 75-579). US Geological Survey.

75. Hiss identified 32 locations on his map as being tests of the San Andres formation within the Hobbs Outflow. These 32 locations were overlaid on the OCD GIS map with a 2000-foot halo around the Hiss points to identify candidates for the source of the sample. Criteria for identifying the well candidate: 1) proximity to where Hiss spotted the data, 2) comparison of the depth of the test as shown in the Hiss database to the completion or test interval of the candidate well at the time the test was taken, 3) date restrictions were imposed so that we only consider wells that existed when the sample was obtained, 4) when the Hiss database did not provide a depth for the sample, multiple wells were identified as potential candidates based on location, depth of the well, and timing of sample date. A confidence level was assigned to each of these identified potential well candidates with many of them being confirmed. We reviewed 202 well files for this effort. Once the well(s) was identified as representing the sample, the geologic tops were used to quality control the formation name listed in the database. The formation name was either confirmed or reassigned based on the tested interval listed in the dataset. Of the 32 Hiss plotted San Andres datapoints, ten of them were determined to be San Andres. Nineteen were determined to not be San Andres and were either from the Artesia Group or Leonard aged formations, or the tested interval was San Andres comingled with another formation. Three of the Hiss datapoints had no candidate well in the area and could not be resolved.

76. Goodnight also gathered San Andres water chemistry datasets from other sources to update and supplement the Hiss analysis. This included the GoTech/NMWAIDS New Mexico Water and Infrastructure Data System[4] which is housed at New Mexico Tech and the USGS National Produced Water Geochemical Database[5] which is the combination of two previous

[4] https://octane.nmt.edu/gotech/Water/producedwater.aspx.

[5] https://www.usgs.gov/tools/us-geological-survey-national-produced-waters-geochemical-database-viewer.

datasets being the USGSBRIET[6] and the NATCARB.[7] The datasets were often inconsistent in the name assigned to the formation although the well API number indicated the same well and the same chemistry test. Any well that was listed as San Andres in any of these datasets was reviewed regardless of agreement with other datasets. There were 57 wells that had been identified as San Andres tests within the Hobbs Outflow. A similar quality control effort was made on these wells as was with the Hiss data, but the effort was streamlined because the datasets identified the well that was sampled. The well files for these identified wells were cross-referenced to the dataset to confirm the formation that was tested given the tested interval and the date the sample was taken. Of the 57 wells identified, 37 were determined to not be San Andres or were comingled tests with other zones. Twenty were confirmed to be San Andres.

77. **Goodnight Exhibit B-60** is the culmination of this quality control work. The exhibit shows all San Andres datapoints that have been identified and quality controlled. The data sources include Hiss, USGS, New Mexico Tech, data obtained from well files, and other publications. The map also included Delaware Mountain Group (DMG) samples as the San Andres is stratigraphically equivalent to DMG and not the Goat Seep or Capitan Reef. This map shows that the San Andres has a marked boundary of rapidly changing salinity when compared to the laterally equivalent DMG indicating that there is very little communication between these two formations. As discussed above, this is due to a loss of porosity and permeability in the San Andres as you move west due to a lithology change because of deeper water deposition.

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[6] Breit, G.N. and Otton, J.K., 2002, Produced Waters Database (http://energy.cr.usgs.gov/prov/prodwat/contact.htm) U.S. Geological Survey.

[7] Bauer, J., et al, 2018, National Carbon Sequestration Database (https://catalog.newmexicowaterdata.org/dataset/natcarb-viewer) United Stated Department of Energy.

78. This quality control effort has been passed to Geolex to undertake a third-party peer review of Goodnights work. Geolex has reviewed and adopted the Goodnight analysis. Geolex will continue the analysis and state their conclusions.

79. San Andres data in the Hobbs Outflow (as defined by OCD Exhibit 2) has an average TDS of around 30,000 ppm but there is a wide range of TDS values. Dr. Trentham provides a discussion of the hydrodynamic relationships that occurred within the San Andres. The connate water was displaced by meteoric water which is why the water salinity in the San Andres is lower than what it is to be expected for its depth. Empire Exhibit D-3 is a map showing Dr. Trentham's mapped San Andres "fairways." He describes the fairways on page 7 and 8 of his testimony in these cases as the following:

> The model for regional flushing of all, or portions, of these reservoirs, developed herein and by Lindsay and Brown (1998, 2001, 2004), identifies the pathway of eastward migrating meteoric waters moving down dip away from the recharge areas between the present day Rio Grande Rift and what is now identified as the western margin of the Northwest Shelf of the Permian Basin (prior to the Laramide orogeny, the Permian Basin reservoir trends extended much further to the west). The late stage (Tertiary), lower salinity waters were following regional aquifer pathways that were entirely different than those followed by the oil during migration into the reservoirs. The initiation of this meteoric-driven flushing was coincident with initial phase of Rio Grande Uplift and Tertiary volcanism in the Trans Pecos, Exhibit D-3.
>
> The original recharge surface extended essentially from the area west of a line from El Paso to Socorro, NM to a line from Carlsbad to north of Roswell. This potential recharge area was half the height of the Permian Basin. During that time, large volumes of initially fresh but soon mixed waters swept through the porous and permeable reservoirs. The mixing occurred rapidly so that the majority of the flushing was with relatively saline, oxygen rich subsurface waters, and referred to as "Mother Nature's Waterflood" (MNW).

80. **These lower salinity waters in the San Andres are not from the Capitan Reef but from San Andres outcrops in central New Mexico that have migrated down these**

fairways. Work by Dr. Lindsay on the EMSU and reported on by Dr. Trentham further supports the concept that the San Andres is not in hydraulic communication with the Capitan Reef. See Goodnight Exhibit B ¶ 39 (McGuire direct testimony).

81. Goodnight has done work to understand what the Capitan Reef water salinity is in the northeast section of the Reef near the area of Goodnight's operations. The OCD has referenced a 2016 publication from the New Mexico Bureau of Geology and Mineral Resources by Lewis Land titled "Overview of Fresh and Brackish Water Quality in New Mexico" in OCD Exhibit 13. Dr. Land describes that fresh water in the Capitan Reef is only in limited areas near the recharge areas.

> Fresh water is present in the [Capitan Reef] aquifer only in the immediate vicinity of its recharge area in the Guadalupe Mountains. Mineral content rapidly increases east of the Pecos River, and throughout most of its extent the Capitan Reef is a brine reservoir, with TDS concentrations >100,000 mg/l in some of the deep monitoring wells in Lea County (Hiss, 1975a; 1975b).

82. Dr. Land goes on to say the following about the Capitan Reef Aquifer as described in the OCD testimony:

> Brackish water resources are clearly available in the Capitan Reef aquifer, although for the most part that water is more accurately described as a brine, and would thus not be suitable for conventional desalination technologies. However, this highly saline water is a valuable resource for industrial applications in southeastern New Mexico and west Texas. Both the petroleum and potash mining industries have recently expressed interest in exploiting brackish water in the reef aquifer for water flooding of mature oil fields in the Permian Basin region and for processing of potash ore.

83. The Capitan Reef near Goodnight's SWD operations cannot be classified as a USDW which is defined as having a TDS value of less than 10,000 ppm. Goodnight has done work to confirm this by taking currently available data from the Capitan Reef. **Goodnight Exhibit B-61** is a map showing currently available data of what the TDS values of the Capitan Reef waters

are. The map is made using multiple public data sources (datapoints are colored by the data source). While there is a limited amount of data on the Capitan Reef salinity, there are more public sources of data than described by the OCD testimony. The map shows that there are only three datapoints that would qualify as USDW. There does not appear to be any trend in the data such that USDW water is mappable or in a defined/confined area. There are USDW datapoints in close proximity to datapoints that are well above the threshold for USDW waters. If the Captain Reef in this area does not meet the standards of USDW then an aquifer exemption should not be needed.

84. Even if the Capitan was USDW quality water, the UIC Primacy Agreement for the OCD's UIC Program (OCD Exhibit 4) has already concluded that the Capitan Reef could be aquifer exempt. The document states the following on page 17.

> It seems reasonable to conclude that the San Andres can be exempted from UIC protection on the grounds that it is economically impractical to use this aquifer as an underground source of drinking water instead of as a brine disposal zone. The same conclusion would be reached for the smaller amounts of fresh water in other aquifers such as the Artesia Group, <u>as well as the more distant supplies in the Capitan Formation</u>.

85. It is unclear why the OCD has not sought to obtain an aquifer exemption for the Capitan Reef even when the UIC primacy agreement has already concluded that an exemption is warranted.

86. Goodnight is currently evaluating the OCD proposed monitoring plan and will be proposing an alternative monitoring plan for the Capitan Reef. It should be noted that Goodnight does not feel that OCD's proposed monitoring plan is justified based on the above discussion but will work with the OCD in a good faith effort to help them obtain data they feel would be useful. Goodnight is currently in the process of identifying wellbores that could be potential candidates to be converted to Capitan monitoring wells. These monitoring wells would be used to sample the water chemistry on an agreed upon cadence to see if there are any material changes to the water

chemistry of the Reef. A baseline must be established along with a clear understanding of what a chemical change means and how the OCD would link any particular change in chemistry to the source of that change. It should be noted that changes in water chemistry observed in the Reef are not diagnostic for confirming that there is communication with the San Andres injection zone. There is proven communication between the Reef and the Artesia Group where there are oilfield operations that could impact the Reef, including saltwater disposal. The OCD has already listed some of the wells of concern which they determined needed further investigation for potential impacts to the Reef (OCD Exhibit 10, Table 1 on page 13). Some of these listed wells are within the Hobbs Outflow and are in the general vicinity of Goodnights operations (within 2.5 to 6 miles). Any change in a new monitoring well in this area would require a thorough investigation of all variables suspected to influence it. Goodnight lacks access to all the necessary data to determine the potential cause of changes observed in Capitan monitoring wells. Goodnight is willing to discuss these issues with the OCD and work to put together a Capitan monitoring effort that would satisfy their needs while taking into consideration Goodnight's concerns.

Conclusions

87. Empire has not shown evidence that supports their claims. They have not shown that there is communication between the San Andres disposal zone and the EMSU Grayburg producing zone. There is a 60-plus-year history of these two activities occurring in the same space simultaneously with no reported problems. The barrier between the two has prevented problems from occurring and continues to do so. There is no evidence that there is a ROZ in the San Andres disposal zone, let alone that the claimed ROZ would be commercial if one existed. In fact, the zone has been already thoroughly tested using a production method identified by Empire's own expert with the San Andres water supply wells and is proven to be negative for ROZ. Goodnight has not impaired Empire's correlative rights or caused any kind of waste given the above conclusions.

88. The OCD should not be concerned with San Andres disposal in the Hobbs Outflow. First, the San Andres is not connected to any part of the Capitan Reef given the up-to-date stratigraphic relationships. The Hobbs Outflow hydrodynamic relationship only exists between the Capitan Reef/Goat Seep and the Artesia Group as they are in stratigraphic communication. Goodnight has done extensive work to update the Hiss model and correct the flaws in the data which was the basis for OCD concerns. This work further concludes that the San Andres is not in communication with the Capitan Reef. Second, the Capitan Reef water offset to Goodnight's injection does not qualify as a USDW. There are many public datapoints available that show the TDS values of the Reef are greater than 10,000 ppm. Based on these conclusions, the OCD should not have any concern about Goodnight's San Andres disposal.

89. Given the above evidence and conclusions, the Commission should 1) deny Empire's applications to revoke the injection authority of Goodnight's currently permitted SWDs in Case Nos. 24018-24020 and 24025; 2) approve Goodnight's request for the five injection authority applications in Case Nos. 23614-23617 and 24123; and 3) approve the allowable daily volume increase for the Dawson SWD in Case No. 23775.

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90. I affirm under penalty of perjury under the laws of the State of New Mexico that the foregoing statements are true and correct. I understand that this self-affirmed statement will be used as written testimony in this case. This statement is made on the date next to my signature below.

Preston McGuire 2/10/2025
Date

REBUTTAL EXHIBIT B-39

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

APPLICATIONS OF GOODNIGHT MIDSTREAM
PERMIAN LLC FOR APPROVAL OF
SALTWATER DISPOSAL WELLS
LEA COUNTY, NEW MEXICO

CASE NOS: 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM
PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403
TO INCREASE THE APPROVED INJECTION RATE
IN ITS ANDRE DAWSON SWD #1,
LEA COUNTY, NEW MEXICO,

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC
TO REVOKE INJECTION AUTHORITY,
LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24020, 24025

APPLICATION OF GOODNIGHT PERMIAN
MIDSTREAM LLC FOR APPROVAL OF A
SALTWATER DISPOSAL WELL,
LEA COUNTY, NEW MEXICO

DIVISION CASE NO. 24123
ORDER NO. R-22869-A

VIDEO DEPOSITION OF DR. ROBERT TRENTHAM
NOVEMBER 5, 2024
9:05 a.m.
VIA ZOOM
Albuquerque, New Mexico

PURSUANT TO THE FEDERAL RULES OF CIVIL PROCEDURE, this deposition was:

TAKEN BY: ADAM G. RANKIN
ATTORNEY FOR GOODNIGHT MIDSTREAM PERMIAN LLC

A. You know, there was -- I can't remember which gentleman it was that presented a lot of the OCD records. That was where I looked at that stuff.

Q. Okay. Are you fam- -- generally familiar with the water supply well production volumes in the EMSU?

A. That's that one well that you're referring to?

Q. Well, there were six originally.

A. Yeah.

Q. Are you familiar with the history of those six water supply wells in the EMSU?

A. Only cursorily.

Q. Okay. So you're not aware that they were -- they produced from the San Andres in the unit?

A. Cursorily I did see that, yes. But I don't know exactly what interval within the San Andres they were producing from.

Q. Okay. So you don't -- you're not aware of the volumes they produced?

A. No.

Q. Okay. That would matter, though -- wouldn't it? -- in your assessment of the -- of the San Andres as an ROZ?

A. It would depend on where the productions of water was from in the San Andres --

Q. Okay.

A. -- to the ROZ.
Q. What would make a difference?
A. Well, I'm -- I'm making some assumptions. I'm assuming that the -- the water productions from deeper in the San Andres, not from the ROZ zone.
Q. Uh-huh.
A. So --
Q. And --
A. -- that would be -- that would be, you know, what I would -- you know, that's just all that I would recommend, you know, that, yeah, if it's -- if it's the lower San Andres, well, that's an entirely different portion of the R- -- of the San Andres; therefore, the ROZ should be all right.
Q. Okay. But you yourself didn't look -- you're not familiar with what zones the water supply wells produced from or whether or not it overlaps with the claimed ROZ; right? You don't know as you sit here?
A. I don't know, no.
Q. Okay. So have you -- your yourself haven't done an assessment or an evaluation of where all the wells are completed within the EMSU Unit? In other words, like, where the producing wells are located and where the water supply was, you haven't done an assessment yourself of all of that?
A. That's correct. That's -- I consider that to be

purposes of -- I'm going to use the word -- phrase "reservoir characterization" to understand where the geologic top of the San Andres is in the EMSU?

A. Oh, absolutely.

Q. Okay. And why? Why does it matter?

A. Because even though they're both carbonate reservoirs and even though they very often produce in the same fields, they're definitely reservoir characteristics. The oil chemistry may be different. The water chemistry for sure is different between those. The top of the San Andres base of the Grayburg is traditionally a barrier to vertical flow. So there's a lot of reasons, that -- yeah, it's an essential pick in any project you do.

Q. Say that part again about the barrier to vertical flow, because I want to make sure I understood what you just said.

A. The top of San Andres base of the Grayburg acts as a barrier to vertical flow. For instance, in the Foster and South Cowden Field that I worked, the project I worked on was actually too deep and into the -- into the areas in the lower Grayburg and San Andres where there had been aqua Grayburg production, and what we discovered was that the water chemistries between the lower Grayburg and the San Andres were totally different. The upper Grayburg originally had total dissolved solids of 27,000 parts per million. The lower -- lower Grayburg had -- was about 37- to 40,000 parts per million total dissolved solids and the San Andres was 62,000 parts per million total dissolved solids so they acted as different reservoirs.

Q. Yeah. So you would agree with me that understanding where that -- if that barrier exists and where it's located is important in characterizing the Grayburg reservoir in relation to the San Andres reservoir?

A. Correct.

Q. Okay. And the reason is because they -- in your experience they function as different reservoirs?

A. Yes.

Q. Okay. Have you evaluated Chevron -- at the time that these water supply wells were drilled, and there's six of them, I represent to you there's six of them, have you evaluated Chevron San Andres top picks in the EMSU water supply wells at the time those wells were drilled?

A. No, I had not.

Q. Okay. So understanding that Chevron drilled these six wells for purposes of providing the makeup water -- the fill-up water and the makeup water from the San Andres, wouldn't you think it would be important to understand where -- where that zone was, this water supply zone?

A. Yes.

Q. Okay. But you haven't evaluated that, so you don't know where that is in relation to the Grayburg or the claimed ROZ zone; right?

A. Correct.

Q. Okay. Now, on that same topic, you haven't yourself evaluated where were this potential permeability barrier is within the EMSU between the San Andres and the Grayburg?

A. That's correct.

Q. Okay. Have you had discussions with Dr. Lindsay about that barrier, that perm barrier?

A. Yes, I have.

Q. And what were those discussions?

A. We talked about the -- the type of a barrier or type of a break it was, what the top of the San Andres looked like versus the base of the Gray. You know, just -- we both had other projects where we know that that's the case, and so we just kind of did a general discussion about, Okay, so is the San Andres here similar to a lot of the other reservoirs that we looked at? And Lindsay's answer to me was yes. So...

Q. In fact, he discusses it at length in this dissertation, doesn't he?

A. Yeah. I have not read all 1400 pages. I'm sorry.

Q. I'm going to quiz you on it. But as to that part, I mean, you're familiar with his dissertation that he before anything occurs to change the state.

So if it's more than a hundred pounds significantly, I would say, yes, there would be a barrier. Other than that, if neither one of them had been tested or produced, you're going to -- there's going to be a pressure differential between them based on depth.

Q. Just based on a hydrostatic column; right?

A. Correct. Uh-huh.

Q. So let's just assume that the EMSU water supply wells were completed in the McKnight member, which is the deeper zone; correct?

A. Yeah.

Q. And -- and I'll represent to you that the EMSU water supply wells have produced more than 350 million barrels of water over more than 20 years. In order for the waterflood in the Grayburg to be successful, wouldn't there need be to a geologic seal between those zones where the waterflood occurs and where the water is produced from?

A. Okay. So in the EMSU, the water supply wells they produce from the McKnight. Okay. And they're water supply wells, and how much did they produce?

Q. More than 350 million barrels.

A. It had to come from somewhere. Didn't all come from the McKnight member. But, yeah, that's def- -- and as

I remember your question, you said between the McKnight and the Grayburg, didn't you say?

Q. The waterflood zone.

A. Yeah, the waterflood zone. Yeah. I would anticipate that there would be an overall regional interval of lower permeability between those two.

Q. Because in order to operate a waterflood, for the waterflood to be effective, you'd have to have a seal between the water supply zone and the waterflood zone; correct?

A. Yes.

Q. They couldn't be in communication because you wouldn't be able to flood the Grayburg?

A. In general, yes.

Q. Okay. I want to transition to another topic that's, again, related, which is, you know, again, sort of the -- this ROZ concept generally, but specific to the EMSU.

Now, in your testimony you talk about -- as I understand, you've identified the San Andres ROZ, residual oil zone, in the EMSU as what you call a "Type 3" ROZ; correct?

A. Right.

Q. And, in general, as I understand it, a Type 3 is created when there's an uplift to the west causing basically meteoric water to flow down dip from the west to east yourself --

A. Other than where I see it in the two cores, yes, correct.

Q. And you haven't -- have you -- have you studied the logs and the analyses of the logs to see if there are other perm barriers?

A. No, I have not.

Q. Okay. But just speaking conceptually, the perm barrier between whatever is the overlying productive zone, okay, the Grayburg, whatever you want to call it, the waterflood zone. I'm going to call it the waterflood zone, okay. I'm not going to get into it with you about what exactly the geologic definition is of San Andres, okay, but anything that is the waterflood zone, okay. I'm going to call it the waterflood zone.

A. Okay.

Q. But there's a barrier between the waterflood zone and the water supply zone. Okay. I'm going to use that phrase, the water supply zone, where the water was withdrawn from. Okay?

A. Okay. All right.

Q. Okay.

A. I'll accept that with the exception that I -- the water supply zone is probably separated from the waterflood zone by a number of hundreds of feet of San Andres.

before you get started.

Q. So going back to my sort of hypothetical about sort of the waterflood zone and then the water injection zone -- rather, not the water injection, the water supply zone. So you have the waterflood zone and then the water supply zone. The water supply zone, would that be -- I mean, if you produce 350 million barrels from that zone, would that be an untouched -- considered to be an untouched zone?

A. That's a good question. My gut tells me that if you're producing that much water, the water has to be replaced. It's not -- you're not draining it. You're not creating Carlsbad Caverns. So the water has -- there's water that's moving in there that has to replace most of that water, so you're changing -- you're doing some change of state to the rock in the water supply zone.

Q. Are you -- are you aware, Dr. Trentham, that that same water supply zone has been functioning as a water disposal zone since the 19- -- before the 1960s in the EMSU?

A. No, I'm not familiar with that.

Q. So you haven't looked at the volumes of disposal that produce water within the San Andres within the EMSU?

A. No, I have not.

Q. Would that -- would that also affect the -- potentially impact the diagenesis or other issues within

A. Near the -- or relative to the exposure surfaces and not -- excuse me -- and not uniformly across the area.
Q. Right. Okay. And then I was asking you about -- kind of near the break or before the break -- about your familiarity with the field, and I asked you in particular about your awareness of the six water supply wells that Gulf and Chevron used to supply the water for the waterflood in the San Andres. Do you recall that?
A. Yes. Uh-huh.
Q. But they're also offsetting to the EMSU approximately another 20 water supply wells within about 15 to 20 miles. Were you aware of those wells as well?
A. No.
Q. Okay. And then -- obviously, this case is about -- you know, you understand that Goodnight is currently disposing of produced water in the -- in an interval within the San Andres; right?
A. Yes.
Q. And I asked you -- I represented to you that there's been saltwater disposal within the San Andres going back into the '60s. Do you recall that?
A. Yes.
Q. But you -- and you were not aware of that; right?
A. Correct.
Q. And then one thing I meant to ask you about is

whether or not you were aware also that Empire currently is injecting produced water into the -- into the San Andres. Were you aware of that?

A. No.

Q. Okay. Just wanted to make sure. I just wanted to kind of, you know, touch on those and make sure I understood whether you were aware or not.

Okay. Now, back to where we left off, which is on discussion about identifying the characteristics of -- of a residual oil zone. Okay. Where we left off was talking about these parameters in your Exhibit D-14, which is in Deposition Exhibit 2.

So we had -- we walked through -- some that we touched on were the comparison to the waterflood at main pay, the -- whether it's more or less homogenous, wettability issues and then whether it's relatively untouched. So I want to kind of get into these a little bit more, in particular the oil saturations.

So you -- in your testimony you refer to a fair bit the Goldsmith Landreth South --

A. San Andres Unit.

Q. -- Andres Unit. Yeah, GLSAU. And I'm going to refer to it going forward as the Goldsmith Unit. I understand that there's another Goldsmith Unit that Dr. Lindsay worked on. But when I refer to the Goldsmith, of a standard to demonstrate that point; that when you look at the core saturations of oil in the ROZ and you compare them to the main pay of a mature waterflood, that the oil saturations are comparable, they look very similar; is that right?

A. Yes.

Q. And that's -- that's the main takeaway from this graph, is that comparison of oil saturations between the two zones?

A. Yeah.

Q. And here, going back to that same point where you identified the range of the ROZ between 20 percent and 40 percent oil saturations, here the cutoff appears to be at approximately, you know, 20 percent. Agree?

A. Yes, about 20 percent. Uh-huh.

Q. And I -- and I, you know, was curious about this so I went back and looked at some other papers, and I know that you guys published some final reports about this field where you've identified on a ten-foot incremental basis the oil saturations for each of these zones, including down to these zones where you've identified these as being noncommercial. Do you recall doing that work?

A. Yes. Uh-huh.

Q. Okay. And here you've identified this as the commercial flood interval, at least for this field. In lithology because there is very little porosity in the interval below the base of the main pay -- below the base of the ROZ, because you've got a change in lithology as well. So there's two things going on there.

Q. Now, so below this 20 percent interval, as I understand it in the Goldsmith, you agree that this interval below 20 percent oil saturation is not commercial. Agree?

A. Yes.

Q. And it's not commercial because of the oil saturations?

A. And the fact there's no porosity and you've a change in lithology from dolomite above to limestone below.

Q. Okay. Those two -- those two factors evaluated -- now, did you discuss the lithology change in your determination, in your papers, in your reports as being a characteristic of that zone not being commercial or not being a target? Do you recall?

A. We didn't talk specifically about a change in lithology indicating a change from commercial to noncommercial. We did mention -- we did talk about the fact that there was limestone below, but this is -- this is one case, and in this one case, if there's a transition from dolomite to limestone, we didn't see that in any of the other ROZ fields where we see the transition from ROZ to the interval below the original oil/water content.

Q. In any of the other ones that you're familiar with, you didn't see a corresponding change in the lithology from, like, dolomite to limestone?

A. Not that I -- not that I can recall. I don't think there was any one.

Q. Okay. So let me kind of drill down a little bit on the oil saturation question. Of the 19 or so projects in the 12 or so ROZ fields -- I'm sorry, Let me restate that.

Of the 19 or so ROZ projects in the 12 dozen or so ROZ fields, are you aware of any pilot or commercial project that is targeting an ROZ interval with oil saturations below 20 percent?

A. They will include that interval in their ROZ, but not specifically targeting it.

Q. In other words, are you aware of any ROZ projects or zones that are targeting intervals that are below 20 percent oil saturation?

A. Not by themselves, no.

Q. Okay. So if there's a -- if there's a depth interval that -- where the oil saturation goes from 20 percent on average, okay -- say there's a ten-foot interval with an average oil saturation of 20 percent. And then every ten-foot increment below that is below 20 percent. Okay. Are you aware of any ROZ projects that are targeting those intervals below the lower most interval match for Seminole San Andres, but that doesn't mean that same history match at Seminole would be -- if you don't have production somewhere else, you can't have a history match, is I guess what I'm saying.

Q. Okay. Well, let me -- let me -- I'm going to put that conversation aside for now, because -- I may come back to it at the end. I don't want to get bogged down on it because I have other things I want to touch on. But I think I may -- I may come back to it. So let's put a pin on it, so to speak, and I may come back and see if I can get my terminology more aligned with how I think you're thinking about it in the interim.

Let's see. Now, and I don't want to, like, get stuck on this 20 percent, but it is a point I want to just make sure I understand. In your testimony that's marked as Exhibit D-2 that you filed in the case here, the parameters that you give throughout is that the ROZ is -- is identified as having an oil saturation be 20 percent and 40 percent.

And based on our discussion, I'm not aware of, and I personally haven't identified any other ROZ projects or developments, pilot or commercial, that -- where the -- and I think you told me, yes, that there's no -- none that you're aware of where the averaged ROZ interval of the entire ROZ interval is below 20 percent; right?

A. That's correct.

Q. Let me -- let me explore that with you a little bit because this is a fascinating topic to me. We talked a little bit about wettability previously and how wettability will influence the -- you know, how sticky, I'm going to call it, the oil is in a zone; right? Like, how it's going to be affected by a waterflood or a -- Mother Nature's Waterflood or how locked in it is; right?

A. Yeah.

Q. Does the wettability of the reservoir have an impact on the core saturations, whether that -- whether the core is influenced or affected by depressurization during the coring process?

A. Okay, well -- so I'll use DUROZ as an example. DUROZ, they don't use CO2. But DUROZ, what they're doing is they're depressurized -- they're depressuring the reservoir by pumping water, in some cases 2,000 barrels a day, to drop the pressure in the reservoir so that any oil that's in we call "dead-end pores," can be produced. Because there's enough gas saturation in there, such that when you drop the pressure of the reservoir, the gas expands and it drives that oil towards the producing wells.

And that's the same thing that happens as you're bringing it up to the surface is you're -- the gas saturation within the oil in these dead-end pores, and even on the -- on the grains, expands that oil and therefore it can be -- it can become movable where at reservoir pressures it was not movable.

Q. So let me -- let me kind of talk through that with you a little bit. So if -- now, in the EMSU San Andres -- and I know you haven't reviewed this and so you're not familiar and I'm just representing to you this is the case -- but more than 350 million barrels of water has been extracted from what we've been talking about as the water supply zone. Okay. In the course of that -- that water production history -- and I'm going to tell you, I think the date is around 2007, or so, when XTO was the operator of the EMSU -- XTO applied for the -- at the division for a venting approval. Okay.

And the wells that they sought approval for to vent were -- included the water supply wells that were producing water from the San Andres. Okay. And I understand that -- that, you know, based on the documentation from the division, that they were venting from the water supply zone.

A. Venting gas?

Q. Venting gas, yeah. Now, we don't have a gas analysis. We don't know what the gas was. But what does that indicate to you was happening in that water supply zone?

A. That they were -- that they were producing some oil, didn't realize it and were reinjecting it into the

Grayburg.

Q. Now, you think they were producing oil?

A. I think they probably were. A small amount, but -- I don't know how much. I know when -- when Marathon had Yates Field, they were producing over 100,000 barrels of water a day, and so they were looking for places to dispose of that water. And so they had -- they made a deal with McCamey Field with Burlington Resources at the time, and they had three very large tanks that they were -- they'd transport the water from Yates Field to McCamey Field, and the water would stay in the tanks long enough that literally even though Marathon said it was just produced water and we want to dispose of it, I think they were taking 50,000 barrels of water a day at McCamey, and they wound up producing 500 barrels of oil from that 50,000 barrels of produced water from the Yates Field because they didn't let it settle long enough for it to -- the oil to break out.

So my guess is if they were making gas out of the water supply wells and making 350 million barrels of water, that they might have made, you know, a significant amount of oil that just got put back into the Grayburg and produced later.

Q. Let me --

A. I wasn't aware of that, but that's kind of -- that's of interest.

Q. Let me kind of -- I'm going to talk through that with you a little bit, because you said to me, I think you're comparing a situation where -- just so I get the terminology out there -- what I think I was describing was a situation where the water supply zone reached the bubble point; is that --

A. Yeah.

Q. -- is that right? Okay. And the bubble point is the point where you --

A. It dropped pressure low enough to reach the bubble point if, as you say, they had venting approval for those water supply zones. Then, to me, they were probably also making a fraction of -- well, I don't know how much, but I bet you they were making some oil.

Q. Now, on that --

A. I guess they're making oil too. So...

Q. On that assumption. We don't know what the composition of the gas is; right? We don't know whether it's, you know, nitrogen, CO2 or methane; right? We don't know? I don't have a composition --

A. No, we don't know that. But I would assume if they had to get a venting approval, it would have to be hydrocarbon gases.

Q. Well, may be. I mean, they included a number of wells, including their waterflood zone wells in a venting --

in the venting request. Okay. So it's not clear. It's not -- I mean, I don't know.

A. Yeah. Yeah, we're both making assumptions, so...

Q. Right. So I just want to talk about those assumptions. So we don't know what gas was being vented; right? But we know some gas -- I mean, apparently some gas was -- right? -- because they asked for approval?

A. Yeah.

Q. So not knowing what the gas was, right, let's think about the zone area. What I'm talking about, it's the -- it's the so-called water supply zone. Okay. And I know you haven't analyzed or evaluated any of the logs in that zone or evaluated, yourself, the details around it.

But if that were the case and then we've reached the bubble point of the water supply zone, and no oil was produced because no oil was reported, okay. And now, you know, I think your point is that maybe it wasn't reported, it wasn't recognized. But my -- what I'm saying is there's no reported oil. Okay. And you haven't looked at the records, so you don't know.

But that being the case, that there was no reported oil, if there were oil you would -- as I understand you to say, you would have expected it to move; right?

A. A fraction of it would have, yes.

Q. Okay. And if -- and if -- and that's because --

and that's the same process that happens with cores when you bring them to the surface; right? They depressurize. You're going to lose some oil because of that depressurization?
A. Yeah. Uh-huh.
Q. Okay. So if -- if there were no oil down there, or there was a small concentration of oil, would that still be a concern looking at your core -- at your conventional cores in the -- in the San Andres?
A. I would think so, because you'd want to see what kind of oil saturation there might be in that zone. Uh-huh.
Q. Now, what I understood you to say was that you -- when you're evaluating cores -- I'm going to say geologists -- that geologists mentally adjust the concentrations. Is there -- is there a mechanism to do it? Is there a rule that you follow to figure out what the core saturations are or should be?
A. Oh, I think everybody has their own valuations to that. It's kind of like, as you say, the A, Ms and Ns, everybody uses a slightly different one. It's just rule of thumb from our experience.
Q. And what's the rule of thumb from your experience?
A. I like the Hess evaluation.
Q. Which is what?
A. With the 17, 24 and 32. The various saturations

porosity -- of oil saturation by depth --

Q. That's probably it.

A. Yeah.

Q. Rather than --

A. That's the only thing I've seen, really. That one, yes.

Q. Okay.

A. So --

A. Yeah, I'll get down to that page, but this is the first -- it's a three-page exhibit. Okay.

A. Okay.

(Exhibit 7 marked.)

Q. (By Mr. Rankin) This is the first page of the exhibit. Did you -- do you recall seeing this when -- in your review?

A. Yeah, that's -- that's the graph from Goldsmith Landreth San Andreson Unit.

Q. The only difference is that Preston added this language here on the side ROZ with an oil saturation cutoff of 20 percent. Do you see that?

A. Yes.

Q. And he put that red line on top of the 20 percent demarcation. Do you see that?

A. Yes.

Q. Other than that, it's the same -- same ambage;

right?

A. Yeah.

Q. Okay. So, yeah, the point here is just we're looking at the cores. And these are conventional cores; right? So these are, at least to you, with an asterisk because you have to evaluate whether or not there's been lost oil in the process of extracting it; right?

A. Correct.

Q. But here we're looking at a range from 20 percent up to -- you know, in the ROZ from 20 percent up above 60 percent; right?

A. Yeah. And those real high numbers probably come in the tightest portion of the reservoir. You know, lowest permeability.

Q. Okay. Because those are the least likely to have been efficiently or effectively swept; right?

A. Right. Yes.

Q. Okay. Now, the next core here on this exhibit is a plot of the core saturations from the EMSU 679 core. And this is one of the cores that you looked at; correct?

A. Yeah.

Q. Okay. And he has -- it's a similar plot. It's meant to sort of imitate or, you know, echo what you guys did in the Goldsmith Unit. And, again, he's got an ROZ saturation cutoff of 20 percent?

A. Yeah.
Q. Based on this, and in comparison to the Goldsmith, do you have any reason to disagree with where Mr. Maguire placed the ROZ interval in this core?
A. No.
Q. Now, there are other cores, and so we -- on this EMSU, and we did the same thing -- or he did the same thing here, and he added those additional cores and shows in this next page of the exhibit the average oil saturations for those conventional cores. And, again, he puts the ROZ at 20 percent cutoff, and the difference here is we can now see the main pay, and we can compare the -- the average oil saturation in the main pay against the average oil saturation in -- in the ROZ. And you -- I mean, I know that -- I don't know if you've done these calculations yourself to come up with an average. Have you?
A. No, I have not.
Q. Do you have any reason to disagree or question the calculations that are represented here as being the average for each of these intervals?
A. So are these the average cutoff or the average -- the average --
Q. These are the --
A. Go ahead.
Q. I was going to say, these are the average oil

saturations --

A. For the entire --

Q. -- as -- for the entire interval as -- in the shaded interval, this grey here, this would be -- is identified as the main pay. So in the unitization documents, the unit is identified as being from minus 100 sub C, and that's -- so that's the top. And this is -- this is the section that has been subject to waterflooding.

A. Yeah.

Q. So that's how we define the -- the average main pay. So that's the average oil saturation from the core analysis.

A. Okay.

Q. Okay. And then -- and then from the ROZ, it's the same -- same process where it's an average of those -- the core analysis plots. Do you have any reason to disagree with what's represented on this exhibit?

A. Well, there's a lot more variability in the oil saturation, but, no. In general, no.

Q. Okay. And you have no reason to disagree with the placement of his -- of his -- you know, his characterization of the base of the ROZ based on those core saturations?

A. No, I have no reason to disagree with it. It looks similar to GLSAU.

Q. Right. Now, in your -- in your testimony, you identified the zone, the interval, the ROZ interval as being from being minus 350 down to minus 719. Now, I understood you to say that that was entirely based on and relying entirely on Dr. Lindsay -- right? -- on his --

A. That's correct.

Q. -- on his interpretation?

A. Yes. Uh-huh.

Q. And you yourself haven't done analysis of the core or any other data to come up with what you believe is the base of the ROZ; right?

A. That's correct.

Q. But based on these logs -- based on these cores, you have no reason to -- to put the base of the ROZ any deeper than it's represented here at minus 652 sub C?

A. Not really, no. I might bring it down a few further feet, but not much, you know.

Q. Okay. There?

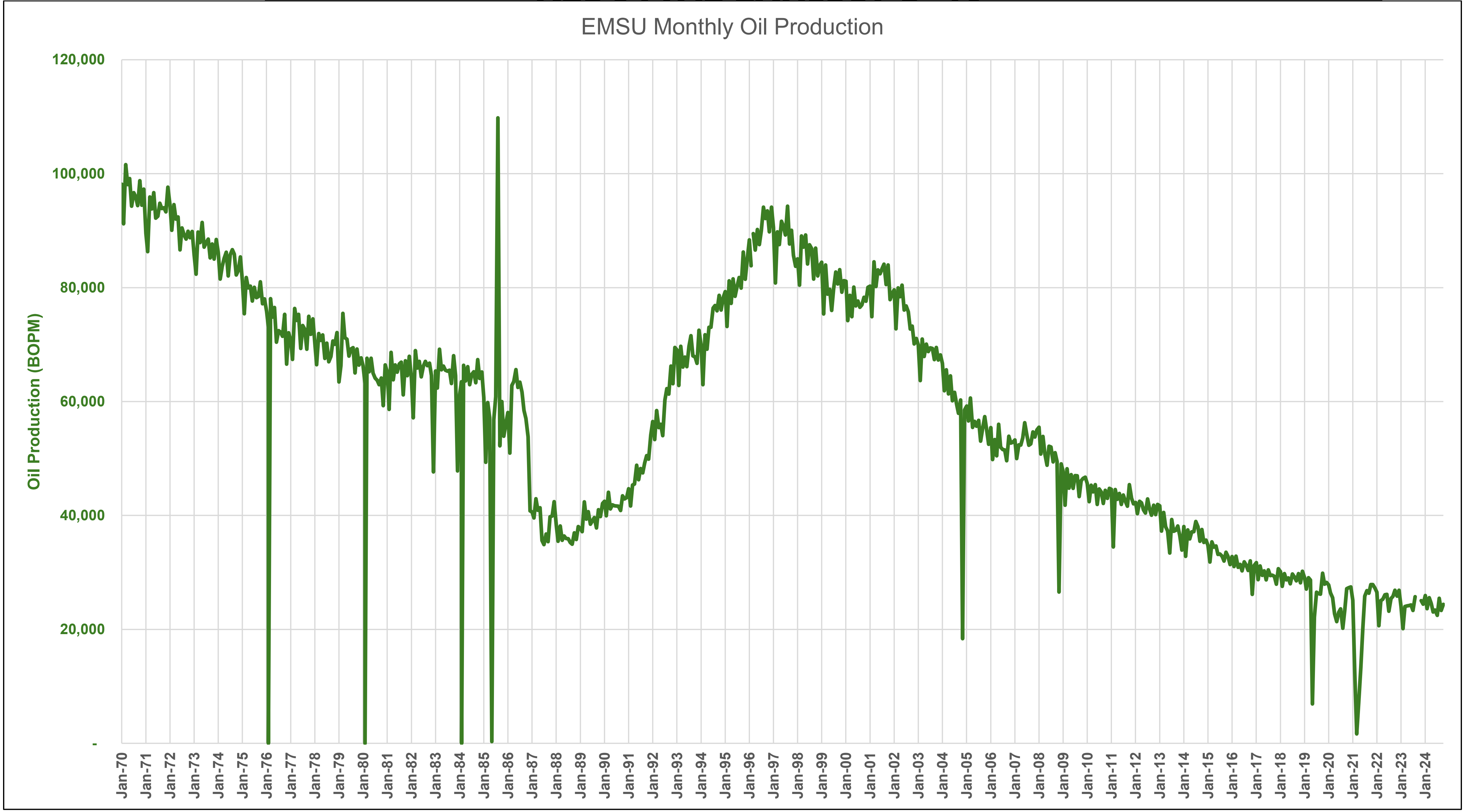
A. Yeah.

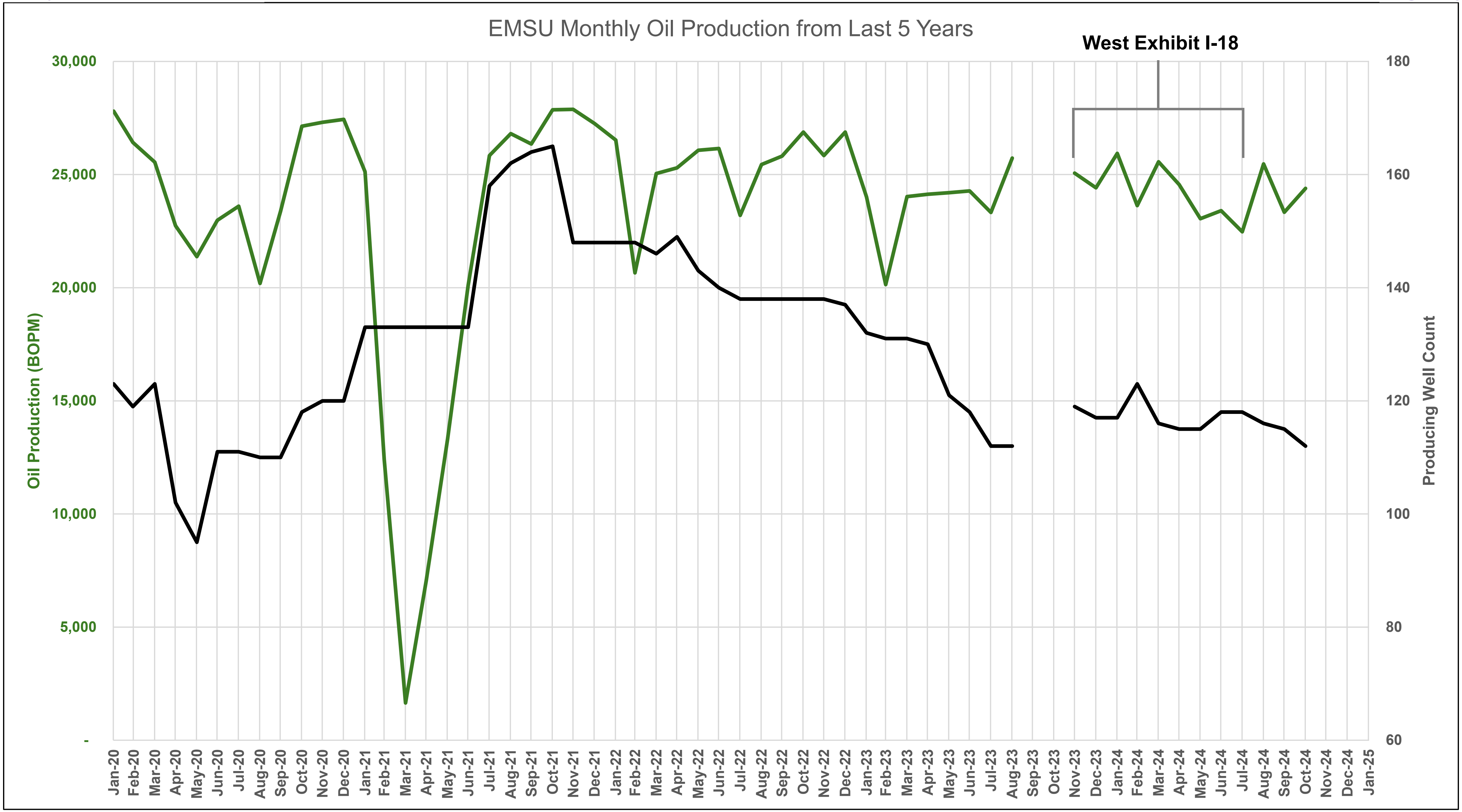
Q. Let's see, we took -- resumed at 12:50. It's 1:50. I may take just a short break here, Dr. Trentham, just a five-minute one, because I have another section, and rather than get started on it, I'm going to take a quick break. Okay?

A. Okay. I appreciate it.

MR. RANKIN: Thank you, guys. Five minutes; so

REBUTTAL EXHIBIT B-40




EMSU Monthly Oil Production from Last 5 Years
West Exhibit I-18
Oil Production (BOPM)
Producing Well Count
30,000
25,000
20,000
15,000
10,000
5,000
-
180
160
140
120
100
80
60
Jan-20
Feb-20
Mar-20
Apr-20
May-20
Jun-20
Jul-20
Aug-20
Sep-20
Oct-20
Nov-20
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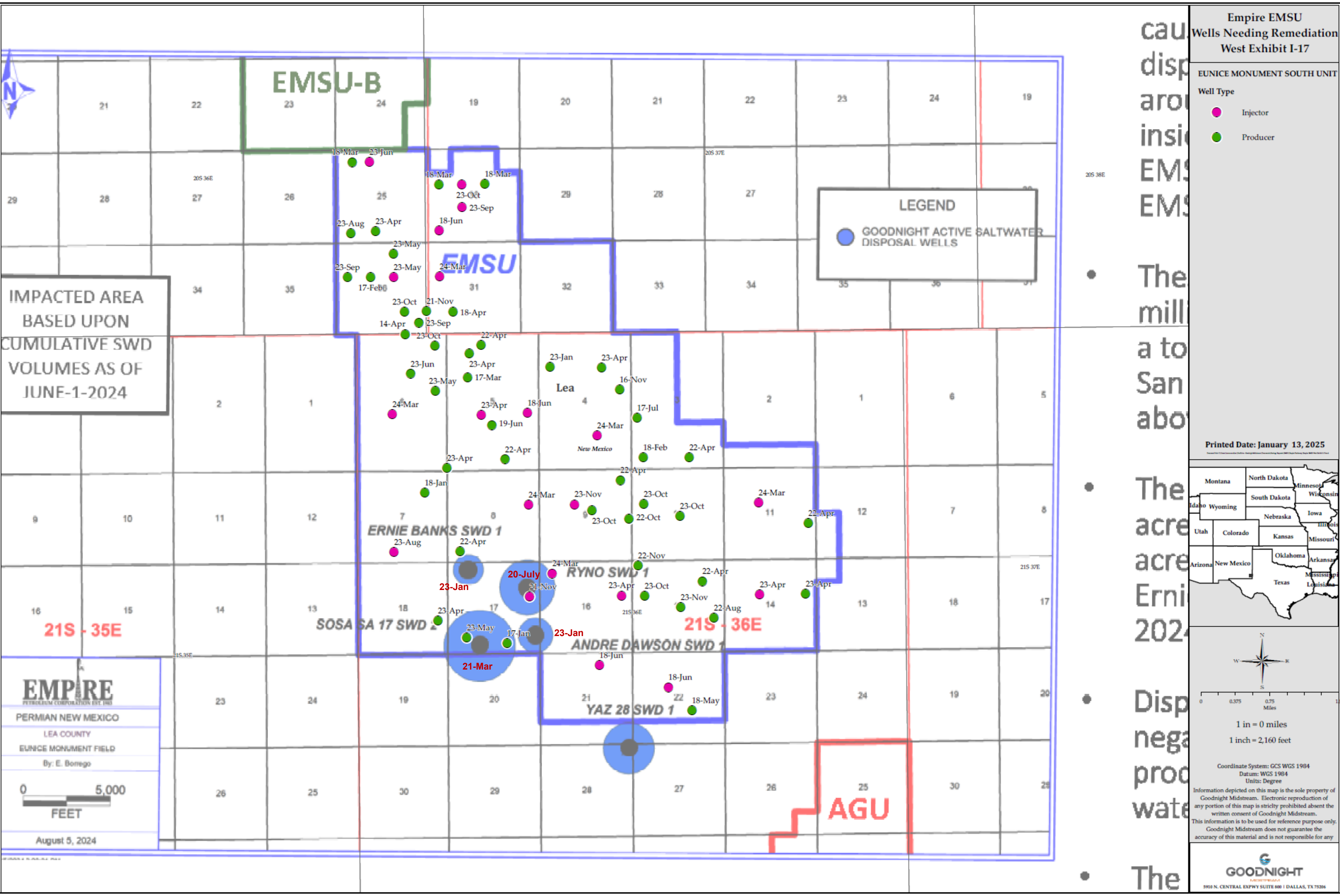
Oct-24
Nov-24
Dec-24
Jan-25

REBUTTAL EXHIBIT B-41



REBUTTAL EXHIBIT B-42

EMSU 321			
Date	TDS	Chloride	Sulfate
4/22/2022	19,590	10,162	677
9/29/2023	19,288	10,012	626
4/8/2024	21,767	11,210	723
10/1/2024	24,234	12,841	599

EMSU 325			
Date	TDS	Chloride	Sulfate
4/10/2022	17,262	8,018	590
9/29/2023	19,443	9,879	515
4/4/2024	21,472	11,124	550

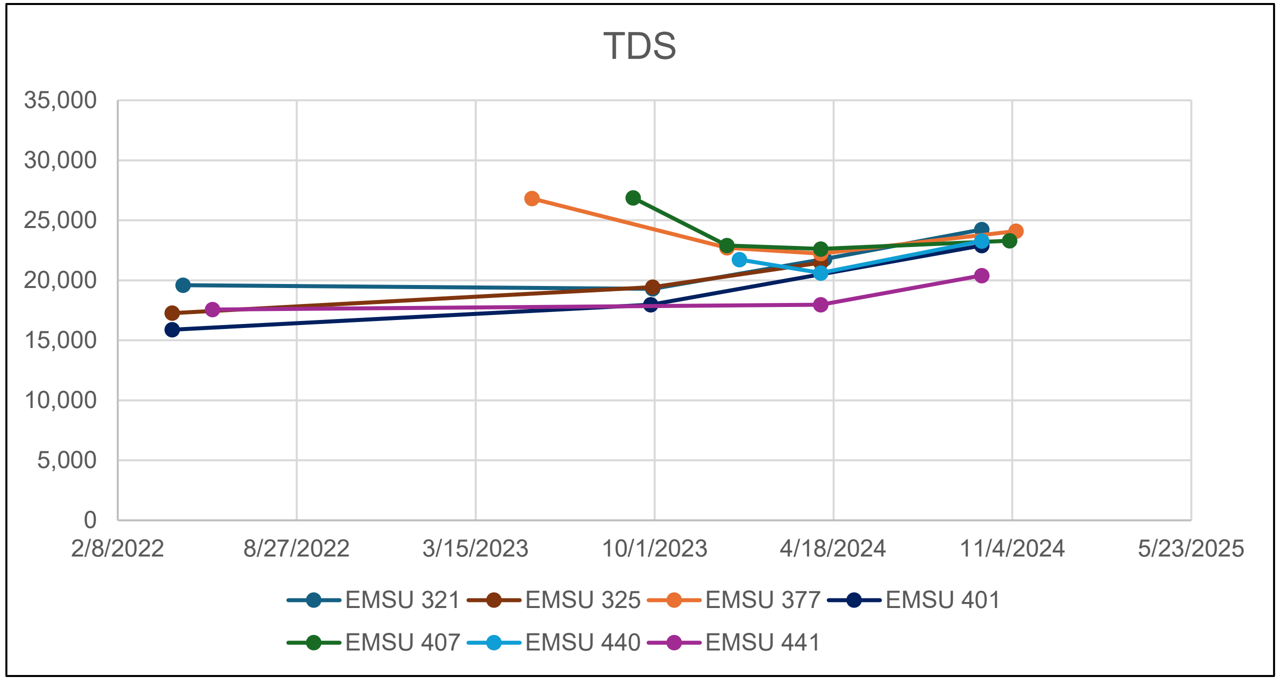
EMSU 377			
Date	TDS	Chloride	Sulfate
5/17/2023	26,813	11,901	529
12/21/2023	22,708	11,593	611
4/4/2024	22,221	11,371	563
11/8/2024	24,084	12,291	581

EMSU 401			
Date	TDS	Chloride	Sulfate
4/10/2022	15,882	7,519	367
9/27/2023	17,956	9,145	424
10/1/2024	22,901	12,035	421

EMSU 407			
Date	TDS	Chloride	Sulfate
9/7/2023	26,874	13,909	624
12/21/2023	22,904	11,681	526
4/4/2024	22,615	11,310	475
11/1/2024	23,292	11,602	468

EMSU 440			
Date	TDS	Chloride	Sulfate
1/4/2024	21,720	11,104	393
4/4/2024	20,614	10,380	366
10/1/2024	23,276	12,284	345

EMSU 441			
Date	TDS	Chloride	Sulfate
5/25/2022	17,562	8,748	106
4/4/2024	17,971	8,943	153
10/1/2024	20,404	10,596	125


TDS
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
2/8/2022
8/27/2022
3/15/2023
10/1/2023
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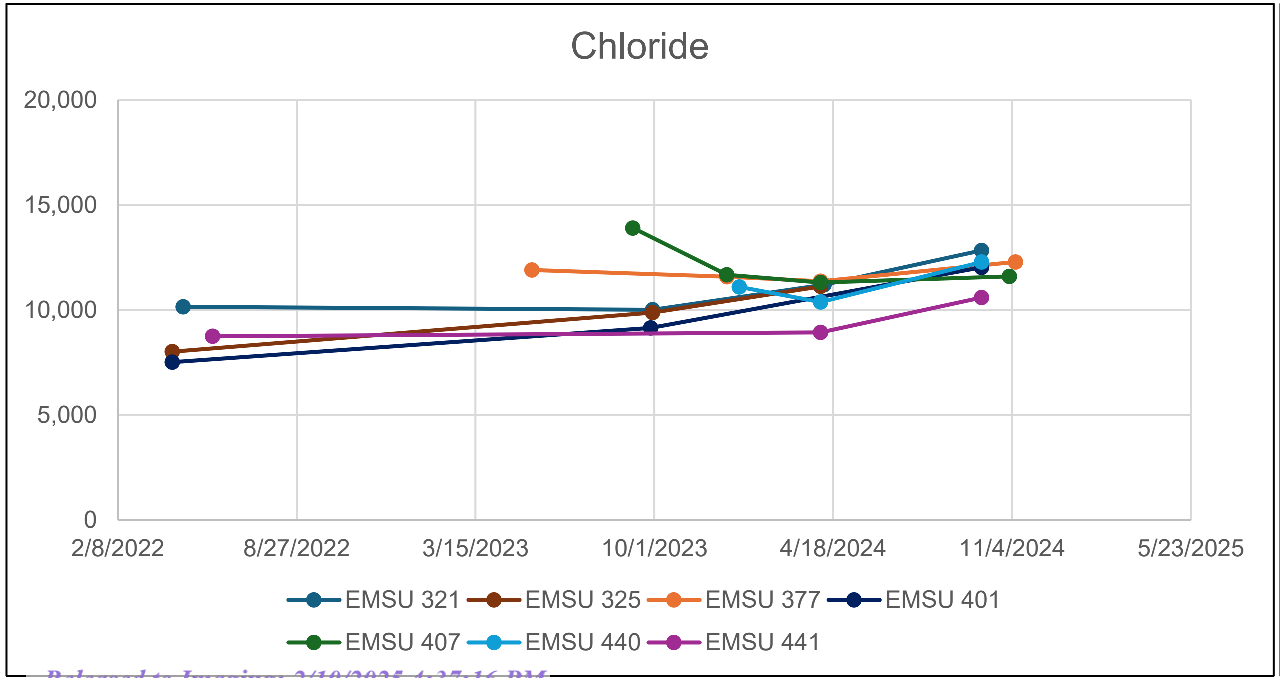
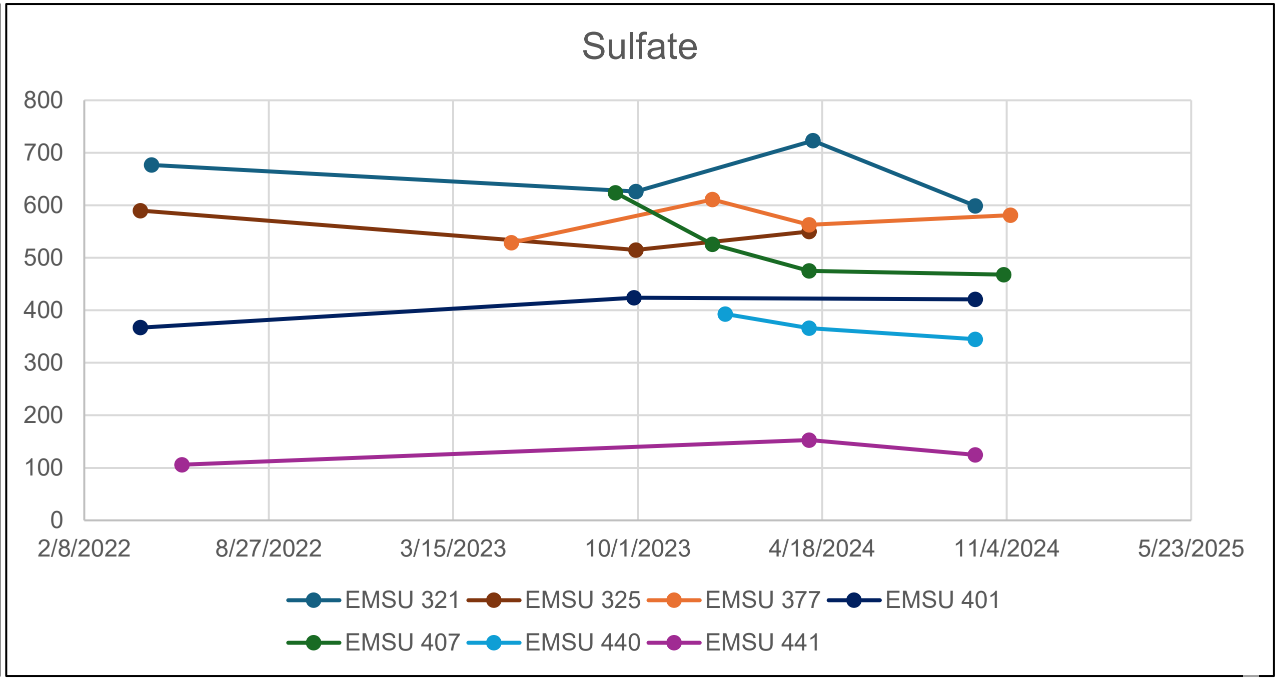
EMSU 407
EMSU 440
EMSU 441


Chloride
20,000
15,000
10,000
5,000
0
2/8/2022
8/27/2022
3/15/2023
10/1/2023
4/18/2024
11/4/2024
5/23/2025
EMSU 321
EMSU 325
EMSU 377
EMSU 401
EMSU 407
EMSU 440
EMSU 441


Sulfate
800
700
600
500
400
300
200
100
0
2/8/2022
8/27/2022
3/15/2023
10/1/2023
4/18/2024
11/4/2024
5/23/2025
EMSU 321
EMSU 325
EMSU 377
EMSU 401
EMSU 407
EMSU 440
EMSU 441

REBUTTAL EXHIBIT B-43

STATE OF NEW MEXICO
ENGERGY MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL AND GAS COMMISSION

APPLICATIONS OF GOODNIGHT MIDSTREAM
PERMIAN, LLC, FOR APPROVAL OF
SALTWATER DISPOSAL WELLS,
LEA COUNTY, NEW MEXICO, CASE NOS: 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM
PERMIAN, LLC TO AMEND ORDER NO. R-22026/SWD-2403
TO INCREASE THE APPROVED INJECTION RATE
IN ITS ANDRE DAWSON SWD #1
LEA COUNTY, NEW MEXICO CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO, LLC,
TO REVOKE INJECTION AUTHORITY,
LEA COUNTY, NEW MEXICO CASE NOS.
20418-20420,20425

APPLICATION OF GOODNIGHT PERMIAN
MIDSTREAM, LLC FOR APPROVAL OF A
SALTWATER DISPOSAL WELL,
LEA COUNTY, NEW MEXICO DIVISION CASE 24123
ORDER NO. R-22869-A

VIDEOTAPED DEPOSITION OF:
ROBERT FORREST LINDSAY
FRIDAY, JANUARY 17, 2025
9:12 A.M.
VIA ZOOM VIDEOCONFERENCING PLATFORM
PURSUANT TO THE NEW MEXICO RULES OF CIVIL
PROCEDURE,THIS DEPOSITION WAS TAKEN BY:
ADAM G. RANKIN, ESQ.
ATTORNEY FOR GOODNIGHT MIDSTREAM PERMIAN

REPORTED BY: Mary Therese Macfarlane CCR No. 122

Q. Do you have an understanding whether that's -- Empire's going to do that?
A. Well, that's up to them. 11:57
Q. You have no indication from them that they're going to do that?
A. They say they will, but that's all I've heard.
Q. Who said that they will? Do you remember who said that?
A. Pardon?
Q. Do you remember who it was that said they will?
A. Will what?
Q. They will take a core of the Lower San Andres.
A. Oh, you'd have to talk to Darrell Davis about that. 11:58
Q. Was that Darrell Davis who told you that they plan to or they will?
A. Uh, yes.
Q. We've talked about this term residual oil zone, the ROZ, but we really haven't talked about how you define it. What is your definition of a residual oil zone? 11:58
A. Anything that has an oil saturation greater than 20 percent, up to at least maybe 40 percent, 50 percent, until you get to the point where you finally have mobile oil in a core. 11:58
Q. Just to confirm that, my understanding is that

aligns with the definition in the literature adopted by Mr. Melzer -- or Dr. -- Mr. Melzer and Dr. Trentham. Agree?

A. Yes, that's correct.

Q. And are you aware of any ROZ Co2 projects that have pursued ROZ zones with oil saturations below 20 percent? 11:59

A. No.

Q. In addition to those oil saturations is it your understanding that oil within an ROZ would be immobile, correct?

A. You know, people -- excuse me. People talk about residual oil zones being just nothing but residual, but in reality when you look at residual oil zones, from top to bottom you go from higher oil saturation to lower. And in the upper part some of that what is called residual is actually mobile or you could never produce it to begin with if you do a residual oil zone now when you drill a well for a residual oil zone. 12:00 12:00

Q. I'm not sure I quite -- I may have been distracted. I wasn't quite following that last bit.

MR. PADILLA: Your calendar's up again.

A. When you look at a residual oil zone from top to bottom, the oil saturations go from higher to lower. In the top of the residual oil zone some of that oil is 12:00

probably mobile or you would never recover it when you do a residual oil zone test.

Q. What's a residual oil zone tests?

A. When you do a horizontal well.

Q. Okay. When -- I'm going to -- I'm going to pin that thought, because I'm going to come back to that.

Just a moment. 12:01

A. Okay.

Q. Is your -- we talked about, you know, the 20 percent oil saturation being sort of the threshold, the baseline for what you consider to be a residual oil zone. Correct?

A. Yes.

Q. And, uhm, so does that -- I mean, if I were to say at least potentially commercial, that would be, in 12:01 your mind, a potentially commercial residual oil zone is one with a threshold, a baseline of 20 percent up to, you know, up to basically the point of mobile oil.

A. That's correct.

MR. RANKIN: Okay. We're at noon our time, and I'm sure -- I don't know about you, Dr. Lindsay, but Dr. Trentham didn't eat lunch. He says he doesn't eat lunch.

So I need to eat lunch, I'm sure others do, too, 12:02 and we're another hour in. I think it's a good place to take a quick break.

And those things are generally mappable across the San Andres, right?
A. Yeah. Yeah, throughout the Permian Basin. In the shelves. Not in the basin, in the shelves.
Q. In the shales?
A. Yes. The shelves.
Q. Oh, shelves.
A. Yeah, the shelf edge. They do not extend out into the basin.
Q. Okay. I got it. All right. 12:51
One question I have is: Are you familiar with the six water supply wells that Chevron drilled in the EMSU and the San Andres to supply water for the waterflood?
A. Yeah. I know where they are, and we've used some of them for well logs because they cored some of them. But that's about it. 12:51
Q. How deep do the cores go on those well log -- on those wells?
A. Shoot, I don't know. They are down into the San Andres. I think they -- some of them, I know this, only went into the Upper San Andres.
Q. Do you have any idea as to --
A. I don't know if all of them -- if any of them got deeper into the Lower San Andres. I don't know that.

Q. You didn't use any of the cores from those wells for your analysis. 12:52
A. Yes, I did.
Q. For the --
A. In the 458 and 457, those were cored, and they are in my -- that main cross section.
Q. Okay. Okay. Now, on the -- those water supply wells, you're familiar with where those wells are, the first perfs are for those water supply wells?
A. No.
Q. Have you evaluated the location of where those -- so do you know whether those wells are completed in the Upper San Andres or the Lower San Andres? 12:52
A. No.
Q. You haven't evaluated --
A. No.
Q. Have you evaluated --
A. All --
Q. I'm sorry.
A. All we used those for was the ones that were cored up in the Grayburg, and I described those cores to build the cross section. But that's all. 12:53
Q. So you didn't look at those wells to determine where Chevron picked the tops in those water-supply wells?
A. At the top of the San Andres?

Q. Uh-huh.
A. Uh, yes, in the 457 and 458 we did. And I'm not too sure about some of the others.
Q. Okay. But you haven't looked at or evaluated where those wells are completed, where the water zone is that they are producing from, -- 12:53
A. No.
Q. -- whether it's the Upper San Andres or the Upper...
A. No. No.
Q. For -- the same for the EMSU 460, 461, 462. You haven't looked at those to determine where those perfs are, whether they are in the Upper or Lower San Andres. 12:54
A. No.
Q. Have you looked at those geophysical logs to determine where the pi marker is on those well logs for the 460, 461, 462, for example?
A. Let's see. For the -- I may have on the 461 years ago looked for the top of the San Andres. I have looked at it for the San Andres in the 458 and the 457, because I utilized those in the cross section.
But on the others, I probably didn't look for the San Andres pick.
Q. Now, just to be clear I'm asking about the top of the Lower San Andres.

A. Oh, no. Some of those wells -- some of those wells only went into the Upper San Andres, from what I understand. Some may have went into the Lower San Andres, but I never looked at it for the Lower San Andres marker. 12:55

Q. Have you yourself evaluated to determine whether, which of the six water-supply wells were only completed in the Upper San Andres?

A. No. No.

Q. So as you sit here today you can't tell me whether the six water-supply wells were completed in the Lower San Andres or the Upper San Andres.

A. No. No.

Q. You haven't --

A. That was of no interest. We were focused on figuring out the Grayburg Reservoir. That was the main 12:55 focus.

Q. Now, even with respect to this contest, this dispute which is focused on the San Andres, you haven't looked at those six water-supply wells --

A. No.

Q. -- for purposes or your analysis today.

A. No.

Q. Were you asked to?

A. They asked me what the pick was in the 458, and so I gave that to them. And I think that's about the only one of the water-supply wells, to the best of my knowledge. 12:56

Q. But you didn't -- so you weren't asked to, and you yourself didn't take it upon yourself to review or analyze the geophysical lots for those water-supply wells.

A. No. No.

Q. Why not?

A. Because I had a bunch of others, and there was enough to make a cross section across the EMSU with these others.

Q. Including the --

A. With these saltwater disposal wells.

Q. Okay. Okay. Okay. 12:57

The other question I had that came up at the end of lunch was about -- remember we were talking about your testimony that changed, and the language that you told me, "potentially deeper", you know, could be potentially deeper than the 750 because you went back and looked at the -- you were able to look at the core and take some 12:57 photographs and see that there was staining below minus 750 subsea. Do you recall that?

A. Yes. Yeah, that's correct, yeah. And then on the 679 and in the R.R. Bell No. 4, the base of the core there was oil stained, as well.

Q. As to the 679, though, that you have the core is the lay person's summary of that process.

A. Yep.

Q. Okay. And it goes from regional uplift, meteoric recharge, structural closes -- closures where, you know, where there was oil, right, swept to a residual oil concentration. Right? 13:28

A. Yes.

Q. Then you had destruction of the recharge area, which is your Rio Grande Rift.

Uhm, then you get the backfill and resaturation of the reservoirs. In this case that only occurred in the Grayburg, right?

A. Well, and in the San Andres, too. It just depends on which field you're looking at. 13:28

Q. As to the EMSU.

A. Well, to EMSU yes.

Q. It did not resaturate the EMSU.

A. Yeah, it did resaturate EMSU.

Q. I'm sorry. It did not resaturate the San Andres in the EMSU.

A. That's correct.

Q. Okay. Now, the next part here that I didn't -- that we haven't talked about yet, although you've alluded to it, is that what you're seeing as the play in these types of ROZs is that folks will go in and drill 13:29

laterally, horizontally, into the upper higher-oil concentrations of the residual oil zone. Correct?

A. Right. Yeah.

Q. And then they would do their completions and they would pump off water. And as I understand you to say, that would -- the purpose of that is to reduce the pressurization. Right?

A. When you release the pressure, that frees the 13:29 oil to migrate out of the core system.

Q. Okay. How much water do you generally need to pump off to do that?

A. Well, to put in a great big pump, first of all. And you have to pump it down hundreds and hundreds of pounds to start to get the oil to flow.

Q. Typically, how many barrels might that be?

A. I don't know.

Q. Hundreds?

A. It -- oh, no. It --

Q. Thousands?

A. Yes. So you've got an interesting problem 13:30 there, because then what do you do with the water, the produced water? So you need a water-disposal well.

Q. And the EMSU had a water-disposal right?

A. Pardon me?

Q. The EMSU has a water-disposal well, right?

A. I think they put one in.
Q. But have you studied that well?
A. No.
Q. Are you familiar with what zone it disposes into?
A. No.
Q. You haven't analyzed that well at all?
A. No.
Q. Okay. So you don't know whether it disposes into the lower San Andres? 13:30
A. No, I have no idea.
Q. Okay.
A. This is just -- what that is, is that's the general recipe for working on a residual oil zone, and one that hasn't been messed up by pumping off water and, you know, all the issues that have happened underneath the EMSU.
Q. You're saying that this recipe would apply in an untouched system. 13:31
A. That's right.
Q. But the EMSU is not untouched.
A. That's right.
Q. Because it's had -- well, what? A long history of water disposal --
A. Yeah.

Q. -- prior to the --
A. Water production and water disposal.
Q. So that's occurred -- that occurred even before the EMSU was created. Right? 13:31
A. Yeah. Well, let's see. No, no. They didn't start producing water until after the unit was made, uh, out of the, say, the San Andres.
Q. That's true. So the water production in those six wells, do you recall -- I believe it -- off the top of my head I believe it was around 1985 and '86, or '86 I think it was, that they started producing the water.
Does that sound right to you?
A. Sounds about right, yeah, because they needed make-up water for the waterflood.
Q. Are you aware of the fact that there were existing saltwater disposal wells at the time within what later became the EMSU?
A. Uhm, nope. Don't know anything about those.
Q. Okay. So all the time that you worked on the EMSU until the present, you never looked at or evaluated any of the history of the water disposal that was occurring on the EMSU? 13:32
A. No. I was -- excuse me. I was too busy describing the cores and trying to build the reservoir architecture on about a meter scale with itty-bitty little

cycles of deposition, and I didn't have time to worry about things like that. That was the production engineers' problem.

Q. So even today you haven't looked at -- I mean, you told me that you looked at some of the SWD operators and the wells that -- the geophysical logs for those wells, right? 13:33

A. Yeah, we've looked at trying to make a cross section through EMSU using, you know, the top of the San Andres, the top of the Lower San Andres, and then trying to correlate, uh, strata in between. 13:33

Q. But you haven't looked at where those saltwater disposal wells, where the disposal perfs are located, what depths or what zones?

A. No. No. No.

Q. But to characterize the San Andres Reservoir, wouldn't you want to understand where different wells are perf'd and what the history of those wells are in the different zones?

A. Down on the road once you get the cross section built, that would be good data to put in, but you have to build the cross section first. 13:34

Q. As you sit here today you are not aware of any of the history of any of the saltwater disposal wells in and around the EMSU into the San Andres, correct?

A. No. I just know that they are being injected into the Lower San Andres, and that's about it.
Q. And you don't know -- uh, your understanding is that the injection is into the Lower San Andres? 13:34
A. Yes.
Q. Okay. And, uhm -- but you don't know the history -- you're not aware, for example, that there were wells that were injecting into the San Andres starting in the 1960s?
A. (Note: No audible response.)
Q. Dr. Lindsay, did you freeze on me? Are you still there?
Does anybody else think he froze?
(Note: Multiple responses.)
THE DEPONENT: Now we're back. Okay.
MR. RANKIN: Did you catch my last question, Dr. Lindsay? Oh-oh.
THE DEPONENT: Here we go. Now we're back. Technology is great when it works.
THE VIDEOGRAPHER: Hold on one second.
Could you bring down the exhibit, because his spotlight light fell off. I got to respotlight him.
Okay. There we go. 13:35
MR. RANKIN: Dr. Lindsay, I think I had a question pending, and I don't remember what it was.

Mary, can you tell me what my last question was?
(Note: The pending question was read.)
A. And the answer is nope, don't know anything about it.
Q. Okay. So this last bit here -- I mean my understanding, when you describe this here in this 13:36 exhibit -- and I'm going to put it back up, because I took it down, real quick. This process that you're describing here of horizontal wells drilling into the upper residual 13:36 oil zone, I've heard that be referred to as DUROZ.
A. Well, some people call it that, or some people 13:37 just call it the upper ROZ.
Q. Okay. And I think that's like depressurization of the residual oil zone, is that right, or upper -- depressurization in the upper residual oil zone?
A. Yeah. Yes.
Q. My question was, you know: How much water do you think -- I guess it probably depends on the reservoir and the conditions, but it's at least thousands of barrels, right?
A. Oh, it's going to be tens of thousands of barrels.
Q. Tens of thousands of barrels.
Hundreds of thousands of barrels?
A. It's a lot. It's a lot, because you have to use

great big pumps, submersible pumps.
Q. Yeah. Hundreds of thousands of barrels, millions of barrels?
A. Oh, no. Tens of thousands, for sure, but that's just off the top of my head.
Q. One thing you don't mention in here is carbon dioxide.
A. Nope.
Q. Why don't you?
A. Well, that's another way to attack the ROZ, but then the catch is you may have to do that with vertical 13:38
wells. So you have an injection well that's vertical that injects water and Co2 and then water, because you want to blanket the -- the -- the Co2 so it won't fly through the reservoir too fast, and you want to push it with water, or alternating gas, and so that pushes oil laterally to a vertical oil-producing well. 13:38
Q. Why --
A. That's another way to attack a reservoir.
Q. Why did you here suggest, or propose, or outline the upper ROZ approach instead of the Co2 approach?
A. Oh, this is the standard procedure for attacking an ROZ, what the recipe is here. But there's some people that are trying Co2 with these ROZs. Kinder Morgan is a 13:39
company that has been trying that in a couple of the

fields. And I don't know much about it, and I don't know how well it's worked, either, but that's another way to attack the reservoir. It's a more traditional Co2 flood, called a WAG, water alternating gas.

Q. And the one that you mentioned, Kinder Morgan, would that be the Tall Cotton that you were thinking 13:39 about?

A. That would be that. And then some other company tried -- in the northern part of Goldsmith they tried a flood there, too, a Co2 flood, to the best of my knowledge. But I know zip about it, because I didn't work on it.

Q. But here in terms of current technology and current approaches to residual oil zones, you're telling me that the standard approach is this upper ROZ horizontal 13:40 approach?

A. Yes. Yes.

Q. Is this what you would recommend be conducted in the EMSU?

A. You got to collect data first. We're data poor.

Q. Data poor in the Grayburg?

A. In the -- well, in the Grayburg we're data poor, because we know very little about the residual oil zone. It's off to the west side. Need more data on that.

And you also need more data on the San Andres

ROZ, as well. 13:41

Q. The other thing --

A. That's your step. That's your first step when you're working on any kind of play is you collect data and you analyze it before you do anything. Otherwise, you're probably going to make a mistake.

Q. So I think based on what you're telling me here -- there was one other thing I was interested about, interested in here, and that's this next sentence that I'm showing on my screen that I'm going to highlight this 13:41 paragraph, where you say that: An ROZ can be subdivided into an upper ROZ that is potentially productive and a lower ROZ that remains ROZ.

The way I think you were doing your cartoon with your finger, right, where you had higher saturations that may be some potentially mobile oil, and then it decreases into lower saturations, you're telling me the target would 13:41 be with horizontal wells in the upper of that. Right?

A. That's correct.

Q. So my understanding is that based on that discussion that the upper ROZ would be that portion that has the higher saturations, right?

A. That's correct, yeah.

Q. What's your cut-off?

A. Well, that's where you need some -- uh, a core

to let you know that. But you want to look at intervals that have anywhere from 20 percent oil saturation and higher, up to 40 or 50 or whatever, whatever's in the 13:42
upper part of the ROZ.

Q. And you would put your horizontal well on the highest saturations, right?

A. Yes. Yeah. And the better porosity, too.

Q. Yeah.

A. Because it's not uniformly porous and it's not uniformly permeable. You have little beds that are kind of like my fingers here. In between my fingers there's better porosity, and where my fingers are there's lower 13:42
porosity. It's very common, because sometimes you get into the ROZs and you have these little meter-scale cycles of deposition, and the upper part's grainy and porous, and the lower part is muddy and less porous.

So if you look at my illustration there, all of the dark lines or the red lines that are going horizontal 13:43
across the field, those are discrete individual cycles of deposition.

And so when you really look at a reservoir really close, you're looking at little meter-scale cycles of deposition.

Q. This is -- and you're talking --

A. You need to correlate everything really well.

Q. And just for the purposes of the court reporter's record, we're looking at Exhibit B-5 here, right?
A. Yes. Yeah, B-5. Yep.
Q. And if I wanted to do a simulation, a reservoir simulation of any kind, I would -- to get an accurate simulation, I would want to understand or incorporate for the Grayburg in the EMSU the data you have on each of these microzones. 13:44
A. Yeah. Yeah. What you would do is look for the bundles that tend to have similar reservoir properties, and the bundles of strata that don't have similar reservoir properties, and you're subdividing them. And then you try to simulate that as best as you can. It's very tricky business. 13:44
Q. I'm going to ask you about --
A. You need data. That's where you need data.
Q. I'm going to ask you a little bit more about simulations in a moment.
A. And I am not a simulation expert, so you don't have to ask too hard of questions.
Q. You're right. Neither am I. So you and I can kind of stay at the 50,000-foot level. 13:44
A. Yeah. But the big key thing of -- like, if you were using this illustration and trying to simulate it,

A. When I was working in Hobbs, we knew that we had water plumes extending up out of the San Andres into the Grayburg. It was common knowledge. And nobody mapped them, because it was such common knowledge, because all you had to do was look at the map where the high water cuts were, and you look at the water, and if it's sulfate-rich water, you knew it was San Andres water. It was kind of that simple. So nobody made a map, but they were there, and they were there before the unit was formed. 14:21 14:21

Q. Okay. Let me ask this question: You said sulfate rich. To you is that a marker that it's San Andres? 14:22

A. Yes.

Q. Is it Upper San Andres or Lower San Andres?

A. It's the San Andres. All of the San Andres is full of sulfate.

Q. Okay.

A. It's water -- it's less than 10,000 ppm and it's sulfate rich, because where the waters came from originally went through evaporite beds and dissolved them, and that's where you got the source of the sulfate.

Q. What's the data base that you rely on for the statement that the San Andres has high sulfates? 14:22

A. A water study.

Q. What water study?

A. The water study performed by Chevron Oilfield Research, by a fellow named Alden Carpenter and his assistant Bill Patterson.

Q. That sulfate -- that water study that was done by Chevron, you don't have it, do you?

A. No. 14:23

Q. And Empire doesn't have it, do they.

A. I don't think they do.

Q. And --

A. But there's a publication by Alden Carpenter that you've actually referred to.

Q. Okay. Is that the -- is that a 1996 SPE?

A. Somewhere around there, yeah. Yeah.

Q. Okay.

A. That was a beautiful water chemistry study.

Q. Okay. So there is the one paper that you're aware of, but to your knowledge you don't have the data, and we haven't been provided data, so we aren't able to 14:23 independently assess your --

A. Yeah.

Q. Your --

A. What I had was my detailed notes that I took when Alden came and presented it to us in Midland for the different water chemistries that he defined for connate water in the Grayburg, bottom water in the San Andres, and edge water coming into the Grayburg. It was a beautiful study. 14:24

Q. Yeah. But no data, right? We have no data to review or to evaluate or assess, and we don't know where the waters -- where the samples came from, how they were handled, or anything like that. Right?

A. No. No. Because Alden did all that work. That was his job. He was a geochemist with Chevron Oil Field Research Company --

Q. Okay.

A. -- out of La Habra, California.

Q. So that's the sole basis for your edification of 14:25 the San Andres as a sulfate-rich water.

A. Absolutely. Yes.

Q. Okay.

A. I look lots of notes to make sure. Lots of notes.

Q. I'm sure you did, but of course we don't have your notes, we don't have the details on the study, or what else they were taken from.

A. The data -- the data is dead accurate that's in there.

Q. In where?

A. Right there on the -- right below. If you go 14:25

down to No. 8, there's the data.
Q. So you're telling me that...
A. This is what -- this is their results in a nutshell right there.
Q. So you're telling me that you think that the San Andres is less than 10,000 parts per million?
A. Yes. Yes. And it's sulfate rich.
Q. Okay. So if I were to show you -- I mean, have you -- is that statement solely based on Mr. Carpenter -- your notes from Mr. Carpenter's presentation? 14:25
A. Absolutely, yeah.
Q. Okay.
A. And there was another study done later that was published in the APEG. I can't remember the author's name right now, but he came and chatted with me, and did a study there around EMSU. And he came up with the same results, that it was, uh, fairly fresh water.
Q. But you haven't done, yourself, an analysis of other available data bases to ascertain or corroborate Mr. 14:26 Carpenter's -- the notes you've taken from Mr. Carpenter's presentation, in terms of the geochemistry.
A. Nope. No. But he -- just let me put it this way: Alden Carpenter was an incredibly good geochemist. When he retired, he was asked by Harvard University to be an adjunct professor in their geochemistry section.

A. Yes. He mentioned in his testimony that there was scaling before the unit was formed.
Q. Now --
A. He did a very nice job of the review on EMSU.
Q. Yeah. He dug into the historical literature, for sure. 14:31
The question I have, though, is about -- back to these wells. You referred to Tracy Love and the work he did showing the high-water-cut wells, and your opinion is -- is your opinion that the high-water cut is associated only with water from the San Andres? 14:31
A. Most likely, yes.
Q. And that would be from the Upper San Andres, right?
A. It would be -- yeah. However the water comes out of the San Andres itself, and the Upper San Andres is right there at the top, so it's probably coming out of it. And it could be coming out of the Lower, too. 14:32
Q. Okay.
A. We just know that it's San Andres water that's ascending up.
Q. That's --
A. From plumes of water.
Q. Your opinion is that's San Andres water coming up. That's your --

A. No. That is a fact, because we analyzed the water and it was sulfate rich.
Q. And that's based on Mr. Carpenter's presentation to you, based on --
A. And basic water chemistry studies done by the Hobbs Division in Hobbs, New Mexico, before that. 14:32
Q. So do you have the data on the Hobbs Division, the water chemistry from the Hobbs Division?
A. No. No. It was common knowledge, though.
Q. Okay. So you're telling me it was common knowledge that there were these plumes --
A. Yes.
Q. -- coming up?
A. Yes.
Q. But Mr. Love would know that, right? He would be informed of that. Right?
A. Yes. And he wrote an SPE paper on it, so you can look that up. 14:33
Q. And -- okay. Very good.
Uhm, I think I can skip over that. (Note: Pause.)
Now, just to make it for the record, Dr. Lindsay. You know, I kind of touched on this, but can you confirm for me that you don't have the water chemistry data either from Mr. Carpenter or from the Hobbs Division

of Chevron, and your testimony that you state here is based on your recollection and your notes that you acquired over time, from the presentation from Mr. Carpenter, and your own personal knowledge. Right? 14:33

A. That's correct.

Q. But because you don't have the data you're unable to provide it to us. Right?

A. No, it's right there on Item 8.

Q. Okay. So it's recreated here, but I don't have the data base itself. I don't know anything about where the wells were, the samples were done. You know, I don't know any of the details that I might want to know to evaluate whether there are problems with assumptions, or what have you; with the way the data was collected; or the values, right? 14:34

A. Well, one of the expert witnesses actually has a report of a document that Alden Carpenter gave as a talk at a conference. So you do have some of the information. 14:34

Q. So we have that. We do have the one Carpenter -- okay. That's fair. I don't disagree on that.

Okay. But that's -- I just want to make clear that we don't have any of the actual data, the data base, we don't know any thing about it. All we have is what you've put here on your testimony.

A. Yep. And that is the truth.
Q. And in 8 where you say, "Additional work confirms three water chemistries to be present," just to be clear the additional work you're talking about there is exactly what you and I were just talking about, Mr. Carpenter? 14:35
A. Yes. So he identified Connate water that's in the Grayburg that has a salinity of 120 ppm, that's barium rich, because happened during what's called Mother Nature's Waterflood, when water swept through the Grayburg it dissolved potassium feldspar grains in the dolomitic sandstones. And the K-feldspar grains actually had barium in the crystal structure, because the potassium ions and the barium ions are the same size, and so they tend to fit together in the crystal lattice of the K-feldspar grains. So when these grains preferentially dissolved that freed-up barium into the connate water. 14:35 14:36
Q. When you say K-feldspar, you mean potassium feldspar?
A. Potassium feldspar, yes.
So these dolomitic sandstones, they're not quartz-rich sandstones, they're almost a subarkose. So they have a lot of potassium feldspar.
Q. When you say 120 ppm you mean 120,000 ppm, right? 14:36

Q. And then it goes to say that -- I'll skip a bullet: Plumes of water were easily identified by water chemistry which identified low-salinity water that contained sulfate. Right? 15:40
A. Yes. Yes. That was the common say to know that you were dealing with San Andres water.
Q. And when you talk about plumes of water being easily identified by water chemistry, again that's Mr. Carpenter's presentation to you. Right?
A. Yes. And then also earlier work, before Alden came into the field, they had done water chemistry on some of the water plumes and realized they were sulfate-rich, too. 15:40
Q. And that was the work done by the Hobbs Division at Chevron, right?
A. Yes. Yes.
Q. Okay. So those two sources. But we don't have that data, right?
A. No.
Q. Okay. So it's just your testimony here on that.
A. Yes. And it was fairly common knowledge.
Q. What I'm interested in here is that you say that plumes of water can be easily identified by water chemistry. Right? 15:41
A. Yes.

Q. So that's something -- I mean, is there any reason to prevent anybody from going out there and measuring water chemistry in wells that are identified as having plumes from the San Andres to see if they have sulfate water?
A. Yes. All you have to do is when you get the sample of water to see if it's low salinity, first of all; and then second or all if it's sulfite enriched. Because --
Q. So --
A. -- there could be two kinds of fresh water: Edge water coming in that is not sulfate enriched that's 15:41
coming from the Goat Seep Aquifer; and then there's bottom water from the San Andres that's coming in that is also less than 10,000 ppm but it's sulfated enriched.
So you look at the water chemistry to see is it low-salinity water, and does it contain sulfate or does it not contain sulfate? Then you know whether it's edge water or bottom water. 15:42
Q. And the only way that you can distinguish, Dr. Lindsay, between the two is based on the sulfate. Correct?
A. Yes. And the oil and the low, less-than-10,000 ppm, too.
Q. But they both have less than 10,000 ppm

fractured communication with the San Andres?

A. No. The whole field is under risk because of that double-hump nature of the anticline. That's putting stress over the whole field. 15:44

When the structure formed, instead of just simply flexing like this (demonstrating), it double flexed like this (demonstrating), and put stress all over the field.

Q. Okay. The reason I'm asking is because, you know, Chevron drilled and operated, and Empire continued to operate a saltwater disposal well right at the top of this crestal structure. Are you aware of that? 15:44

A. Hmm, no.

Q. So you don't know the history of that saltwater disposal well and how much volume it's disposed into the San Andres?

A. No. No.

Q. Is it surprising to you that Chevron would choose to put a saltwater disposal well right on a crestal high, if that were a concern?

A. Well, wherever we looked we found fractures, so that doesn't matter. The catch is if you are going to put in a well there, you just want to make sure you cement it in really good or you're going to have all sorts of problems. 15:45

Q. Okay. But you hadn't done -- you were -- Empire didn't tell you about this EMSU saltwater disposal well.
A. Uh, no. No.
Q. And you didn't independently research that well yourself. 15:45
A. No. No, not at all.
Q. Now, the -- my question to you about-- you know, you were pointing out that there's two potential sources of water, right? One is the San Andres, and one in --
A. There's three.
Q. Three. Okay. The San Andres? 15:46
A. Yeah. You've got the connate water in the reservoir.
Q. Okay.
A. And then you've got the edge water; and then you've got the bottom water.
Q. So I guess one of my thought -- the reason I referred to two is as two additional sources outside of the EMSU.
A. Okay. 15:46
Q. So one would be the edge water coming in, and the other would be the Upper San Andres water coming from the bottom, right?
A. Yes.
Q. And as you're sitting here today, the way you

A. No. No, not at all.
Q. But based on what you know about the different fluids and how they interact within the EMSU, would you agree that any reservoir simulation list that's intended to model the EMSU should include entry of Goat Seep edge water as part of that model?
A. Oh, absolutely. Absolutely. Yes. You have to account for all the water movement within the reservoir. bottom water coming up, edge water coming in. 15:52
Q. You mean -- it wouldn't have -- that's a big part of the EMSU story, is that edge water.
A. Yes. Yes, through time. Gee, it started way back in 1934 through 1937 is when the first edge water started to be sucked into the reservoir. 15:52
Q. And if a reservoir simulation of the EMSU did not include Goat Seep edge water encroaching in or moving into the EMSU, it couldn't accurately represent the fluid movement or production in the EMSU. Would you agree?
A. No, probably not.
MR. RANKIN: Dr. Lindsay, I'm going to take 10 minutes, until 4:00 o'clock, just to make sure I've got everything that I want or need, that I covered all my topics. 15:53
THE DEPONENT: Okay.
MR. RANKIN: I know that Mr. Moander is going to

REBUTTAL EXHIBIT B-44

Ref: Item VII of C-108

Martin Water Laboratories, Inc.

P. O. BOX 1468
MONAHANS, TEXAS 79756
PH 943-3234 OR 563-1040

709 W. INDIANA
MIDLAND, TEXAS 79701
PHONE 683-4521

RESULT OF WATER ANALYSES

LABORATORY NO. 284226
SAMPLE RECEIVED 2-15-84
RESULTS REPORTED 2-20-84

TO: Mr. Stan Chapman
P.O. Box 670, Hobbs, NM

COMPANY Gulf Oil Exploration & Production Company LEASE
FIELD OR POOL
SECTION ___ BLOCK ___ SURVEY ___ COUNTY ___ STATE ___

SOURCE OF SAMPLE AND DATE TAKEN.

NO. 1 Make-up water. (San Andres)

NO. 2 Produced water. (Grayburg)

NO. 3

NO. 4

REMARKS:

CHEMICAL AND PHYSICAL PROPERTIES

	NO. 1	NO. 2	NO. 3	NO. 4
Specific Gravity at 60° F.	1.0465	1.0051		
pH When Sampled				
pH When Received	6.80	7.22		
Bicarbonate as HCO_3	964	1,830		
Supersaturation as $CaCO_3$	75	120		
Undersaturation as $CaCO_3$	---	---		
Total Hardness as $CaCO_3$	5,400	800		
Calcium as Ca	1,400	144		
Magnesium as Mg	462	107		
Sodium and/or Potassium	23,244	2,308		
Sulfate as SO_4	3,432	300		
Chloride as Cl	36,575	2,841		
Iron as Fe	0.27	7.5		
Barium as Ba				
Turbidity, Electric				
Color as Pt				
Total Solids, Calculated	66,077	7,530		
Temperature °F.				
Carbon Dioxide, Calculated				
Dissolved Oxygen, Winkler				
Hydrogen Sulfide	600	325		
Resistivity, ohms/m at 77° F.	0.126	0.935		
Suspended Oil				
Filtrable Solids as mg/l				
Volume Filtered, ml				
Calcium Carbonate Scaling Tendency	NONE	NONE		
Calcium Sulfate Scaling Tendency	NONE	NONE		

Results Reported As Milligrams Per Liter

Additional Determinations And Remarks We see no evidence in the above results that would indicate any incompatibility when mixing these two waters in any proportion. Please contact us if we can be of any additional assistance in this regard.

EXHIBIT NO. 336
Case No. 8397
November 7, 1984

Form No. 3

By Waylan C. Martin, M.A.

REBUTTAL EXHIBIT B-45

Well No	Number	API No	API14	Min P	Min_P_filtered	arit_mean	avg_SIP	min_SIP	min_SIP_reviewed	inj P_PM	SI	Date/Time	Day	Mo	Year	Time	cluster	Notes
EMP INJ 116 PSI	116	30-025-06290	30025062900000	6	6	131	222	6	844	12		Fri, 12 Jan 2024 15:03:21	12	Jan	2024	15:03:21		
EMP INJ 118 PSI	118	30-025-29598	30025295980000	184	184	641	261	252	252	261		Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 134 PSI	134	30-025-06306	30025063060000		312	529	348		317	324		Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 148 PSI	148	30-025-29946	30025299460000		68	584	100		68	127		Fri, 03 Nov 2023 08:03:33	3	Nov	2023	8:03:33	2	
EMP INJ 183 PSI	183	30-025-04493	30025044930000	459	681	707	683	670	670			Fri, 03 Nov 2023 08:03:33	3	Nov	2023	8:03:33	2	
EMP INJ 201 PSI	201	30-025-04472	30025044720000		17	338	69		77	77		Tue, 06 Feb 2024 06:47:20	6	Feb	2024	6:47:20		
EMP INJ 225 PSI	225	30-025-29683	30025296830000	1	53	428	581	53	53			Sun, 21 Jan 2024 13:56:54	21	Jan	2024	13:56:54		
EMP INJ 229 PSI	229	30-025-04467	30025044670000	381	672	708	699	695	696			Fri, 03 Nov 2023 14:17:16	3	Nov	2023	14:17:16	2	
EMP INJ 231 PSI	231	30-025-04464	30025044640000	522	686	737	747	707	744			Thu, 02 Nov 2023 13:22:22	2	Nov	2023	13:22:22		
EMP INJ 241 PSI	241	30-025-04489	30025044890000	78	545	578	609	550	550			Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 251 PSI	251	30-025-04520	30025045200000	427	503	599	599	587	587		rev	Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 261 PSI	261	30-025-04471	30025044710000	455	690	753	830	825	825			Fri, 03 Nov 2023 14:17:16	3	Nov	2023	14:17:16	2	
EMP INJ 263 PSI	263	30-025-04456	30025044560000	388	492	573	564	425	492		rev	Fri, 01 Dec 2023 10:52:50	1	Dec	2023	10:52:50		
EMP INJ 273 PSI	273	30-025-04609	30025046090000	516	681	737	733	516	712			Mon, 25 Dec 2023 23:29:58	25	Dec	2023	23:29:58		
EMP INJ 275 PSI	275	30-025-04603	30025046030000		518	569	392		597			Tue, 05 Dec 2023 08:18:44	5	Dec	2023	8:18:44		
EMP INJ 285 PSI	285	30-025-24563	30025245630000	126	225	283	302	278	278			Tue, 30 Jan 2024 09:43:35	30	Jan	2024	9:43:35		
EMP INJ 295 PSI	295	30-025-04560	30025045600000	102	102	354	328	102	102			Wed, 08 Nov 2023 08:31:12	8	Nov	2023	8:31:12	6	
EMP INJ 299 PSI	299	30-025-04571	30025045710000	29	622	683	678	29	650			Tue, 07 Nov 2023 13:50:02	7	Nov	2023	13:50:02	6	
EMP INJ 316 PSI	316	30-025-29882	30025298820000	455	651	712	725	715	715			Thu, 16 Nov 2023 12:43:35	16	Nov	2023	12:43:35	5	
EMP INJ 318 PSI	318	30-025-29901	30025299010000	112	112	145	140	121	121			Fri, 17 Nov 2023 10:31:37	17	Nov	2023	10:31:37	5	
EMP INJ 320 PSI	320	30-025-04578	30025045780000		179	539	571		622			Wed, 20 Dec 2023 12:41:43	20	Dec	2023	12:41:43		
EMP INJ 322 PSI	322	30-025-04574	30025045740000	377	547	571	557	550	550			Wed, 08 Nov 2023 11:38:04	8	Nov	2023	11:38:04	6	
EMP INJ 334 PSI	334	30-025-04544	30025045440000	522	687	715	702	687	687			Tue, 21 Nov 2023 11:04:23	21	Nov	2023	11:04:23	1	
EMP INJ 342 PSI	342	30-025-04583	30025045830000		306	378	68		553			Tue, 26 Dec 2023 15:04:17	26	Dec	2023	15:04:17		
EMP INJ 344 PSI	344	30-025-04592	30025045920000	337	337	759	787	559	743			Mon, 26 Feb 2024 12:37:59	26	Feb	2024	12:37:59	3	
EMP INJ 348 PSI	348	30-025-04607	30025046070000	125	125	475	505	482	482			Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 358 PSI	358	30-025-04642	30025046420000		298	445	444	309	421			Mon, 26 Feb 2024 18:51:42	26	Feb	2024	18:51:42	3	
EMP INJ 360 PSI	360	30-025-04649	30025046490000		570	637	638	570	570			Mon, 26 Feb 2024 15:44:50	26	Feb	2024	15:44:50	3	
EMP INJ 368 PSI	368	30-025-04697	30025046970000	489	489	686	684	489	667			Mon, 15 Jan 2024 14:41:12	15	Jan	2024	14:41:12	4	
EMP INJ 370 PSI	370	30-025-04684	30025046840000	364	364	458	444	364	436			Mon, 15 Jan 2024 14:41:12	15	Jan	2024	14:41:12	4	
EMP INJ 380 PSI	380	30-025-04701	30025047010000	421	421	432	431	421	421			Fri, 17 Nov 2023 13:38:29	17	Nov	2023	13:38:29	5	
EMP INJ 386 PSI	386	30-025-04652	30025046520000		122	455	582	122	375			Mon, 26 Feb 2024 18:51:42	26	Feb	2024	18:51:42	3	
EMP INJ 388 PSI	388	30-025-04641	30025046410000	497	497	750	746	497	709			Mon, 15 Jan 2024 14:41:12	15	Jan	2024	14:41:12	4	
EMP INJ 398 PSI	398	30-025-04647	30025046470000	94	94	645	757	738	738			Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 400 PSI	400	30-025-04653	30025046530000	477	477	682	667	517	517			Wed, 13 Dec 2023 21:51:42	13	Dec	2023	21:51:42		
EMP INJ 402 PSI	402	30-025-04665	30025046650000	380	380	697	709	681	681			Wed, 29 Nov 2023 15:16:45	29	Nov	2023	15:16:45		
EMP INJ 404 PSI	404	30-025-04688	30025046880000		11	308	656	3	688	0		Tue, 21 Nov 2023 14:11:14	21	Nov	2023	14:11:14	1	
EMP INJ 426 PSI	426	30-025-08711	30025087110000	446	446	679	716	709	709			Fri, 17 Nov 2023 16:45:21	17	Nov	2023	16:45:21	5	

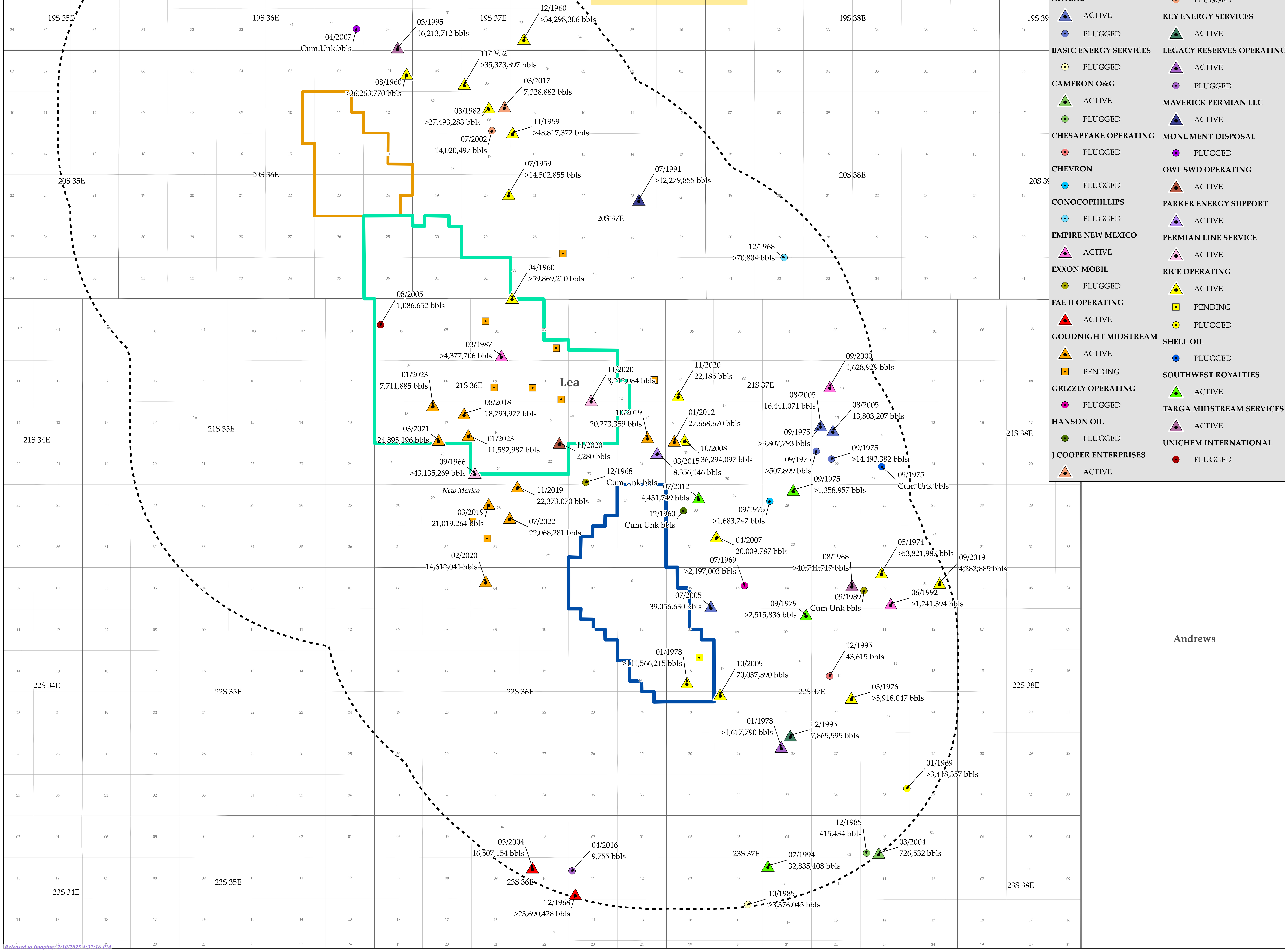
524
Avg. Reviewed SIP

REBUTTAL EXHIBIT B-46

API	Well Name	POD	Produced Volume (Bbls)	Source
30-025-06737	ARGO A #005	CP761	10,158,116	OCD
30-025-06741	ARGO A #009	CP730	13,289,425	OCD
30-025-06742	ARGO A #010	CP731	7,853,600	Reconstruction from well test
30-025-31234	ARROWHEAD GRAYBURG UNIT #600	CP760	82,575,467	OCD plus reconstructed volumes from well tests
30-025-31303	ARROWHEAD GRAYBURG UNIT #601	CP761	21,975,448	OCD plus reconstructed volumes from well tests
30-025-21664	EAST EUMONT UNIT #1	L5569	16,000,000	From unitization hearing 16,000,000 bbls makeup water needed
30-025-29149	EMSU #457	CP670	42,169,647	OCD plus reconstructed volumes from well tests
30-025-29618	EMSU #458	CP694	50,335,998	OCD plus reconstructed volumes from well tests
30-025-29826	EMSU #459	CP697	108,178,865	OCD plus reconstructed volumes from well tests
30-025-29620	EMSU #460	CP693	65,118,299	OCD plus reconstructed volumes from well tests
30-025-29621	EMSU #461	CP695	19,365,192	OCD plus reconstructed volumes from well tests
30-025-29622	EMSU #462	CP696	71,477,525	OCD plus reconstructed volumes from well tests
30-025-06846	EUNICE KING #010	NO POD	6,275,575	OCD
30-025-26601	HAWK FEDERAL B 1 #016	NO POD	14,350,284	OCD plus reconstructed volumes from well tests
30-025-06835	J N CARSON NCT C #008	CP1739	3,040,484	OCD
30-025-08784	J F JANDA NCT F #017	CP369 & CP848	5,906,150	OCD plus reconstructed volumes from well tests
30-025-06639	LOCKHART A 17 #004	NO POD	40,728,236	Reconstruction from well test
30-025-31268	MCDONALD STATE A/C 1-16 #001	CP764	25,220,790	Reconstruction from well test
30-025-22629	New Mexico S State #4	NO POD	12,950,830	Reconstruction from well test
30-025-24082	NORTH MONUMENT G/SA UNIT #009	L6933	4,163,276	OCD
30-025-31505	NORTH MONUMENT G/SA UNIT #018	NO POD	43,443,369	OCD
30-025-33618	NORTH MONUMENT G/SA UNIT #624	NO POD	64,454,000	Reconstruction from well test
30-025-05640	B V CULP NCT A #008 (North Monument)	L5433	Unknown	No docuemts identified to reconstruct volumes
30-025-31733	SOUTH EUNICE 26 STATE #001	CP776	31,362,816	Reconstruction from well test
30-025-21774	STATE A AC 2 #60	NO POD	23,449,684	Reconstruction from well test
30-025-06758	TURNER #16	CP733	68,261,680	Reconstruction from well test

852,104,756 Total Volume

REBUTTAL EXHIBIT B-47



San Andres SWDs

AGU Outline
EMSU Outline
EMSU -B
5 mile buffer

Printed Date: January 14, 2025

N
W
E
S

Miles

1 in = 1 miles

1 inch = 5,220 feet

Coordinate System: GCS WGS 1984
Datum: WGS 1984
Units: Degree

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GOODNIGHT MIDSTREAM

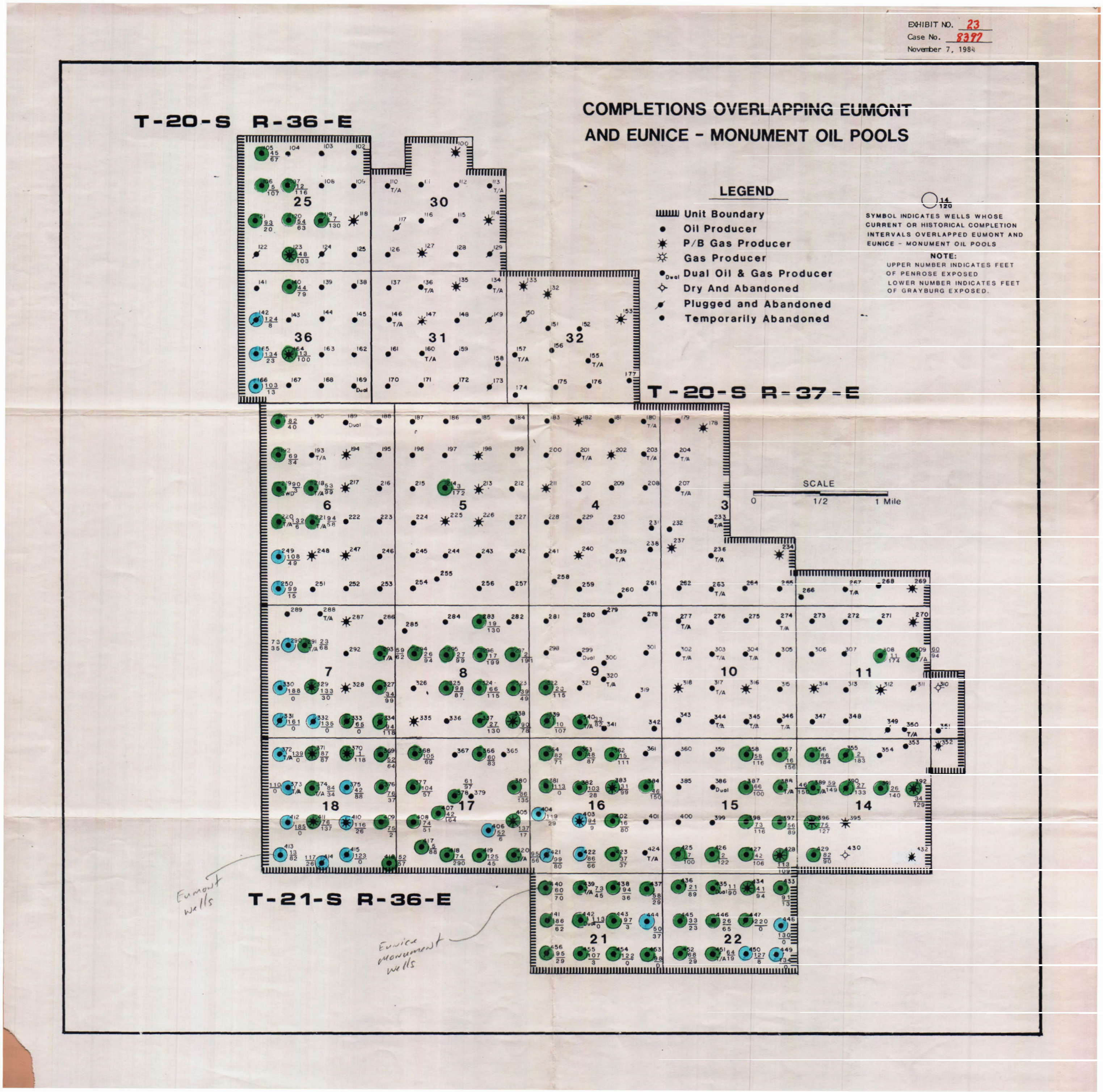
5910 N. CENTRAL EXPWY SUITE 800 | DALLAS, TX 75206

REBUTTAL EXHIBIT B-48

Buchwalter Wells With Modified KZ

API	Well #	KB	Bottom of Comp. (MD)	Bottom of Comp. (SS)	Open Hole
30-025-04321	104	3567	4053	-486	OH
30-025-04330	108	3549	4037	-488	OH
30-025-04332	120	3561	4120	-559	
30-025-06285	128	3529	3900	-371	
30-025-06303	136	3531	3932	-401	OH
30-025-12543	144	3550	4036	-486	OH
30-025-29946	148	3550	3804	-254	
30-025-06324	156	3541	3840	-299	
30-025-06311	158	3547	3892	-345	OH
30-025-06300	160	3540	3840	-300	OH
30-025-04419	162	3534	3965	-431	OH
30-025-06297	170	3546	3985	-439	OH
30-025-06322	176	3541	3829	-288	OH
30-025-04493	183	3547	3844	-297	OH
30-025-04513	184	3556	3859	-303	OH
30-025-04515	187	3561	4000	-439	OH
30-025-04511	197	3578	4005	-427	OH
30-025-04469	210	3567	3870	-303	OH
30-025-04504	212	3577	3887	-310	OH
30-025-04657	218	3568	3912	-344	
30-025-04502	227	3596	4020	-424	OH
30-025-04467	229	3567	3864	-297	OH
30-025-04468	239	3588	3946	-358	OH
30-025-04489	241	3594	3896	-302	OH
30-025-04520	251	3590	4059	-469	OH
30-025-04462	259	3577	3900	-323	OH
30-025-04471	261	3585	3890	-305	OH
30-025-04612	271	3541	3840	-299	OH
30-025-04598	275	3576	3901	-325	OH
30-025-04593	277	3607	3912	-305	OH
30-025-04573	280	3581	3921	-340	
30-025-04577	281	3571	3894	-323	OH
30-025-04539	293	3603	4032	-429	OH
30-025-04587	301	3594	3904	-310	OH
30-025-04597	305	3595	3886	-291	OH
30-025-04578	320	3582	3940	-358	OH
30-025-04574	322	3585	4023	-438	OH
30-025-04559	326	3604	4034	-430	OH
30-025-04592	344	3573	3960	-387	OH
30-025-04607	348	3613	3932	-319	OH
30-025-04629	356	3581	3941	-360	
30-025-04649	360	3585	3945	-360	OH
30-025-04662	362	3591	3950	-359	OH
30-025-04653	400	3596	4031	-435	OH
30-025-04665	402	3612	3966	-354	OH
30-025-04696	406	3651	4116	-465	OH
30-025-08711	426	3599	4052	-453	OH
30-025-04750	436	3619	3970	-351	OH
30-025-04749	444	3608	4008	-400	OH
30-025-04753	446	3622	3962	-340	OH

REBUTTAL EXHIBIT B-49



REBUTTAL EXHIBIT B-50

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:) CASE NO. 12,320

APPLICATION OF CHEVRON U.S.A. PRODUCTION COMPANY FOR APPROVAL TO CONVERT THE EMSU WELLS NOS. 210, 212, 222, 252 AND 258 TO INJECTION IN THE EUNICE MONUMENT SOUTH UNIT, LEA COUNTY, NEW MEXICO

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MARK ASHLEY, Hearing Examiner

March 2nd, 2000

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MARK ASHLEY, Hearing Examiner, on Thursday, March 2nd, 2000, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

Q. Now, I believe you mentioned something in your direct testimony that you don't believe you've filled up the reservoir yet; is that correct?

A. No, sir.

Q. All right, and you've been pumping water in for how many years now?

A. Fifteen.

Q. Fifteen years. Have you done any injection-to-withdrawal-ratio calculations for the waterflood unit as a whole?

A. Yes, that's what I just presented.

Q. Okay. What is the injection-to-withdrawal ratio?

A. Right now, fieldwide, we're averaging about 1.1.

Q. 1.1 what?

A. The ratio, fluid in to fluid out.

Q. Barrels? It's measured in barrels?

A. Reservoir barrels to reservoir barrels.

Q. And the barrels in are measuring water?

A. Yes, sir.

Q. Are the barrels out measuring just water?

A. No, that's oil, gas and water.

Q. All right. What about -- Have you done any injection-to-withdrawal-ratio calculations just for water, to see if there's any water that you can't account for in terms of the injection?

A. Yes.
Q. Okay, and what do those show you?
A. They show in some areas that we're producing more water than we've put in. And that comes from the edge water to the west, there's an edge water encroachment to the west, and the wells on the west side exhibit more water influx than we put in.
Q. Okay, what about the rest of the waterflood area?
A. No, we produce most everything we inject.
Q. Okay, and that's always --
A. Except for on the west side where you have the edge water encroachment.
Q. Okay, and that's always been the case?
A. Yes, sir.
Q. All right.
A. Except for the start of the flood before the water broke through in some of those high-permeability streaks. We have a real bad problem with cycling water through those high-permeability streaks. They're like pipelines, and until those broke through we were -- you know, water production was lower.
But once the injection broke through, you're almost at one with your water in, water out, till you squeeze out of those high-permeability streaks.
Q. Let me go back, if I could. Let me ask you this.

Are there ways for an operator to calculate reservoir fill-up in a waterflood unit such as this?

A. Yes.

Q. And have you done those calculations?

A. Yes, sir. You allocate injection and production based on well pattern alignment.

Q. Okay, and can you just describe for me again where that is on your exhibit?

A. That would be display -- or Exhibit Number 13.

Q. Okay. Does Exhibit 13 show everything that you've done in that regard to try to determine the status of the reservoir with respect to fill-up?

A. It shows the cumulative injection and production for each injector-centered pattern and the allocated -- using the allocated production injection for that pattern.

Q. Okay. Well, I guess my question is, have you done any other calculations aside from what is shown in Exhibit 13 to give you an idea of reservoir fill-up at this point in time?

A. Yes, sir, there's been a full field simulation done on this field, and it shows we have still not reached fill-up.

Q. Okay, and where is that?

A. That is at Chevron Petroleum Technology Company.

Q. Is there any particular reason you didn't include that in the exhibit packet?

A. Didn't find it necessary, when you've got sound reservoir engineering principles right here.

Q. Let me go back to Mr. Hartman's letter, point 3), there at the bottom of the first page, where he asks that "The wellhead injection pressure for the proposed injection wells will always be kept at or below the NMOCD's maximum surface injection pressure limit of .2 p.s.i. per foot."

What is it that you find objectionable about that?

A. Currently we'll keep it at that level, but if we -- as reservoir pressure increases, injection rate decreases. Therefore you have to increase injection pressure to maintain the same injection rate.

Q. Okay, but you wouldn't increase the injection pressure without the approval of the Division?

A. No, sir, we'd use step-rate tests witnessed by the OCD to increase our injection pressure.

Q. All right. And then Number 4) in Mr. Hartman's letter asks that you assure that "The primary cement job for the proposed injection wells has not been compromised by nitro-glycerine stimulation or excessive acid treatments."

Do you find that objectionable?

A. Yes, because we really can't control what was

 REBUTTAL EXHIBIT B-51

SPE International
Society of Petroleum Engineers

SPE 49201

Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood Conformance

Tracy Love (Chevron USA), Andrew McCarty (Chevron USA), Matthew J. Miller (Dowell), and Mark Semmelbeck (Enron)

ABSTRACT

The Eunice Monument South Unit (EMSU) produces from the Grayburg formation in southeast New Mexico. The unit has higher than expected water production and lower than expected oil production since a waterflood was installed in 1986; poor vertical flood conformance is to blame. A major project was initiated in 1996 to characterize the reservoir and improve the flood conformance where possible.

Reservoir characterization included mapping high permeability streaks, material balance, and percent pore volume swept calculations. Two techniques, production data diagnostics and injection well diagnostics, were then applied to characterize the performance of individual wells. The subsets of wells that were identified as underperforming by each method were compared and a focus area was selected to pilot test a waterflood conformance correction program. Primary problems discovered included water cycling through high-permeability streaks, water injection into the gas cap, and wellbore zonal isolation problems.

The waterflood conformance correction program comprises problem diagnosis, treatment selection and design, treatment execution, and treatment evaluation. Several different treatments (cement squeeze, near-wellbore gel treatment, and deep-penetrating gel treatment) were executed depending on the problem encountered. This program has been implemented on 29 wells in EMSU. Production response to the treatments is discussed.

Introduction

The Eunice Monument field is located in southeastern Lea County, New Mexico, approximately 15 miles southwest of Hobbs, New Mexico, along the northwestern edge of the Central basin platform. The original Eunice pool was discovered in 1929 and developed on 40-acre spacing. Oil production peaked in 1937 at 25,542 barrels of oil per day.

Chevron currently operates two adjacent waterflood units in the Eunice Monument field, the Eunice Monument South Unit (EMSU – 14,190 acres) and the Eunice Monument South Unit B (EMSUB - 3000 acres). The EMSUB shares a common unit boundary along the northwestern border of the EMSU (southeast corner of the EMSUB). EMSU was unitized February 1, 1985, with water injection commencing November 1986. EMSUB was unitized December 1, 1990, with water injection commencing March 1991. Both units are developed on 40-acre well spacing with 80-acre 5-spot patterns. EMSU and EMSUB produce oil primarily from dolomites of the Grayburg formation. A minor amount of oil is produced from the overlying lower Queen (Penrose). The underlying San Andres formation, a water drive reservoir, is used for supply water. Hydrocarbon entrapment in the field is controlled by a combination of structural-stratigraphic trapping located along the northwest margin of the Central Basin Platform.

As of April 1, 1998, EMSU consisted of 164 active producers, 138 active injectors, 4 water supply wells, and 1 water disposal well. EMSUB consisted of 49 active producers and 51 active injectors. The injection facilities are shared by both units.

Lithology. The Grayburg is a carbonate ramp environment, relatively thick and porous to the southwest (more packstones/grainstones) and thin and tight to the northeast (more wackestones/mudstones). Sets of parasequences stack to form six recognizable zones based on correlations of relatively thin (approx. 2- to 10- ft thick), generally impermeable sandstones (siliciclastics). The zonal markers that can be correlated across most of the unit are made up of dolomitic sandstones (subarkose to calclithites), which are composed of well-sorted and very fine-grained siliciclastic sand. These siliciclastic "markers" are very well developed to the northeast in the back-shoal environment, which makes zonal correlations fairly obvious and straightforward. To the southwest, however, in the high-energy shoal environment, these siliciclastic markers are much less developed and confidence in the zonal correlations deteriorates. These siliciclastics tend to be very porous but are impermeable and therefore act as vertical barriers to fluid movement. The general lack of siliciclastics to the southwest in the high-energy shoal environment--where thick, porous, grain-rich parasequences tend to stack--has produced a more homogeneous reservoir that has more of a bottom- and edge-water drive component. To the northeast, in the back-shoal environment, the siliciclastics tend to vertically compartmentalize thinner, less porous, and more muddy parasequences that promote more of a solution gas-drive component.

Zones 1, 2, and 3 are very clean dolomites (floodable reserves, solution gas drive). Top of Zone 1 is the top of the Grayburg. Generally, Zone 1 has been processed by waterflooding. It is tight in the northeastern half of the field and because of this, it is more brittle and tends to be more fractured than the rest of the Grayburg section. The lower half of Zones 1 and 2 have the most high permeability streaks (solution enhanced grainstones typically 18-in to 4-ft thick) and tend to have edge water drive connected to the Grayburg shoal along the southwest of the field.

Zone 4 is clastic rich (silty/sandy) and forms a pressure barrier. It is vertically impermeable and can have good porosity zones. This zone has a karsted surface in its upper portion.

Zone 5 is typically water drive (3 to 20% oil cut) and Zone 6 overlies the top of the San Andres and contains an unconformity in its upper part. There are oil shows well down into the San Andres.

Waterflood performance. The total oil production rate at EMSU decreased after the waterflood was implemented in 1986 primarily due to conversions to injection (**Fig. 1**). However, patterns did suffer from rapid water breakthroughs, slow pressure increases, and low injection:withdrawal ratios. In all, the oil production rate decreased in 70% of the wells in the field after the waterflood was implemented (**Fig. 2**). It is believed that poor reservoir flood conformance reduced the waterflood effectiveness. The EMSU Waterflood Conformance Project was initiated in 1996 to characterize the flood conformance and correct it if feasible. The project focus area (referred to as the conformance diamond) consists of 16 contiguous 80-acre producer center patterns. Several elements of this project are described in this paper.

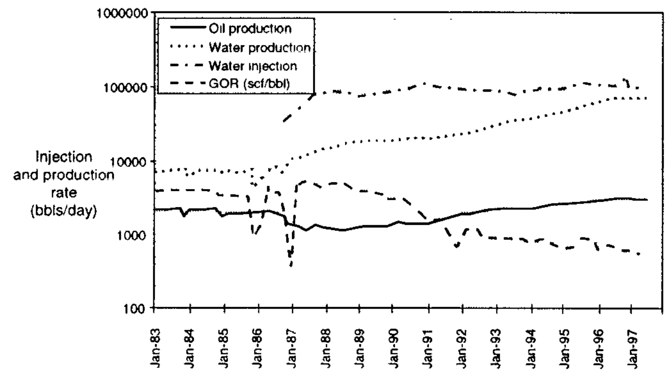


Fig. 1.– Illustration of EMSU production history. Water injection began in 1986.

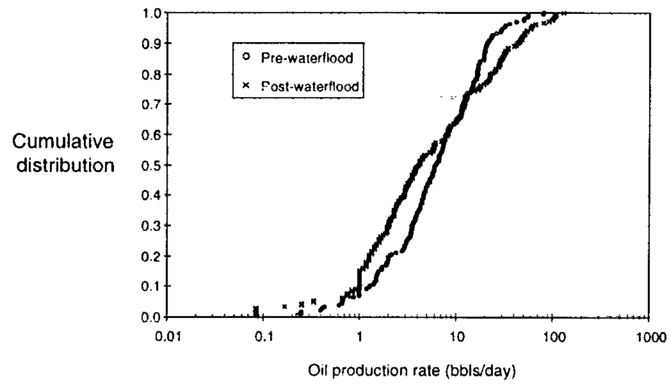


Fig. 2.– Comparison of prewaterflood and postwaterflood oil production rate.

Reservoir Characterization

The EMSU reservoir characterization was a long process that included the creation of conformance cross-sections, mapping of high perm streaks, calculating the percent hydrocarbon pore volume swept for each major zone, and production diagnostics.

Conformance cross-sections. Conformance cross-sections were built for each producer-centered pattern in the field. Injection profiles, porosity, gamma ray traces, and wellbore configuration history were correlated by structure for each well. These cross-sections were useful for verifying strong injector-producer correlations, identifying thief zones, and provided data for the zonal processing calculations. Permeability from core data was used, when available, to confirm the location of high-permeability streaks. **Figure 3** illustrates one of the structural cross-sections built for EMSU. The cross-section line from well 257 to 259 is show in **Fig. 8**.

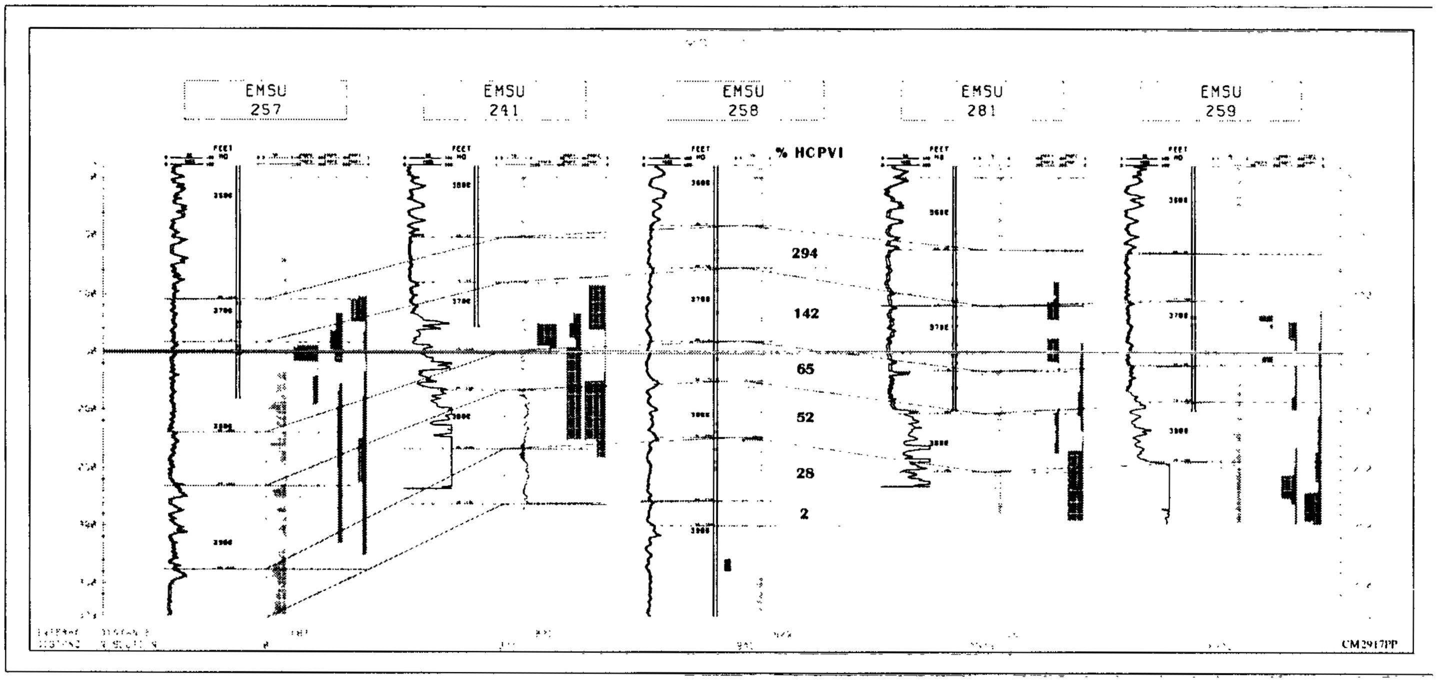


Fig. 3.– Structural cross-section.

The visual representation of the wells in each pattern facilitated the study of fluid movement in the pattern. It also highlighted the fact that a substantial fraction of the injected water was entering the gas cap (formation above the -150-ft marker). Zone 1 and the majority of Zone 2 are in the gas cap throughout the conformance diamond.

Mapping of high perm streaks. Maps of high permeability streaks were created for each zone and/or perm-streak trend in order to capture their aerial extent. Core permeability data, core descriptions, and log data were used in constructing these maps. Where permeability data was absent or limited, geostatistical models were incorporated.

Zonal processing. A waterflood monitoring tool, developed by Chevron Petroleum Technology Center, was used to calculate the zonal processing of each zone. Moveable hydrocarbon pore volume calculations were generated for each pattern accounting for S_{wi}, S_{or}, and S_{gr} as immobile. Monthly injection volumes were then allocated to each zone using injection profiles and the cumulative injected volume was calculated for each zone. A straight line interpolation was used to account for changes in injection profiles between the dates each profile was run. Sweep efficiencies were not accounted for. The monitoring tool showed that Zones 1 and 2 were overprocessed, and Zones 3, 4, and 5 were underprocessed. An overprocessed zone had more than 100% of the hydrocarbon pore volume swept by water. Visual inspection of the conformance cross section gave a quick indication of vertical sweep efficiency and lent more credence to the seriousness of the over processing.

Production diagnostics. Production diagnostics for water or CO_2 floods utilize six plots. They are as follows:

1) production history
2) production diagnostic plots (WOR and WOR' versus time)[1]
3) production decline curves (oil and water versus cumulative barrels of oil)
4) injection and production pattern plots (BWIPD from offset injectors, BWPD, and BOPD all versus time)
5) injection withdrawal ratio ($Q_{injection}/Q_{production}$).
6) production and injection data contour and bubble maps.

These plots and maps are used as an initial screen for production well performance. The information gathered may indicate the well's general production mechanism. Typically, a few specific pieces of additional information must be collected to confirm suspected production mechanisms and problem types.

The data required for production diagnostics are monthly average BOPD, BWPD, and BWIPD and/or Mscf/D for each pattern. It is helpful to have a brief description and history of the field and the individual wells. The well history should contain the dates and description of workovers. The field history should include the general characteristics of the reservoir structure and dates when major field events occurred; i.e., pattern realignment, unitization, infill drilling, waterflood installation.

The production diagnostics were used to assess the severity of water cycling between injector and producer pairs. Characteristics of a water control candidate include a strong correlation between injected and produced fluid rates, a sharp increase in the WOR versus time plot, and a sharp decrease in the rate of oil production. The oil rate decreases sharply at the onset of water injection because the injected water races through a highly transmissible pathway and overwhelms the lift capacity of the production well. The resulting high wellbore fluid level suppress the oil production from low-pressure, low-permeability zones, sometimes resulting in downhole crossflows..

The signature of a direct communication between an injector and producer is shown in **Figs. 4-6**. Three plots in particular were used to ascertain the degree of communication between the injectors and the producers. The plots used were the injection and production pattern plots, **Fig. 4**, the injection withdrawal ratios, and the production diagnostic plots, **Fig. 5**.[1]

Figures 4-6 illustrate examples of each plot for a high degree of injector to producer communication. **Figure 4** indicates that water increased and oil decreased in the producer soon after injection began. **Figure 5** shows a step change in the WOR at the onset of water injection. This WOR change occurs at the same time as the oil rate decreased to around 1 bbl/day (**Fig. 6**). These are symptoms of a serious conformance problem that may be correctable depending on the nature of the problem.

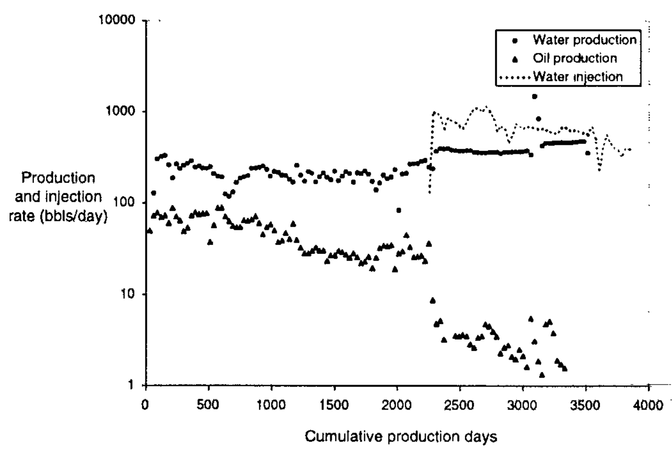


Fig. 4.– Illustration of oil rate decrease and water rate increase that coincide with injection in an offset injector.

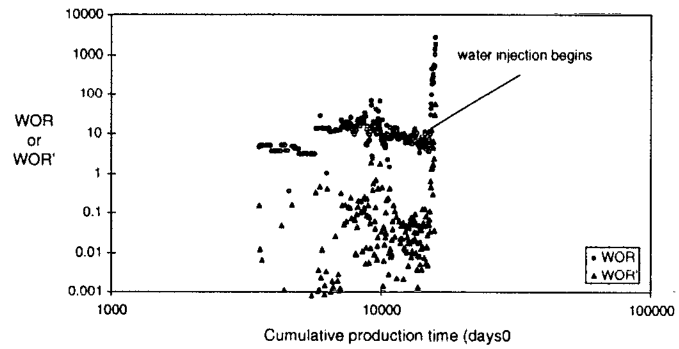


Fig. 5.– Diagnostic plot for a production well in direct communication with an injection well.

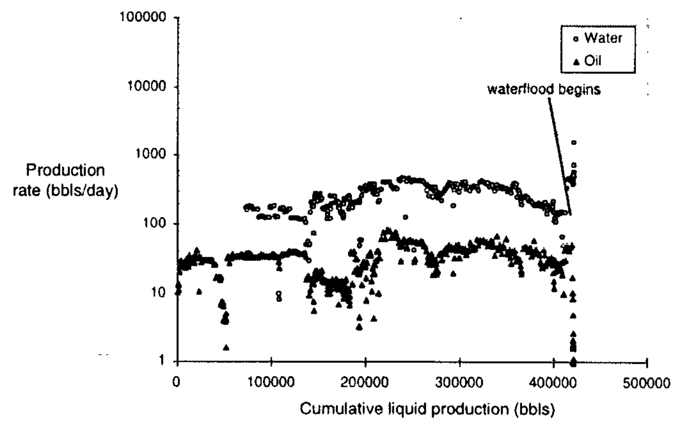


Fig. 6.– Oil rate decline for a production well in direct communication with an injection well.

Focus Area

Conformance problems were observed over the entire field (**Fig. 7**). A focus area, referred to as the conformance diamond, was defined as a pilot area for the conformance improvement work (**Fig. 8**). It was verified during the reservoir characterization that the conformance diamond contained natural fractures, injection into a gas cap, and areally extensive permeability streaks; all of which cause the characteristics illustrated in **Figs. 4-6**. Furthermore, these problems were isolated to Zones 1 and 2 in the conformance diamond. The overall goal for the conformance diamond was to increase oil production and decrease water cycling. The steps taken to achieve the goals include elimination of water injection into the gas cap and stimulation of underprocessed zones in both injection and production wells. Injection into the gas cap was initially allowed at the onset of waterflood to eliminate the possibility of sweeping oil into the gas cap and decrease fill up time.

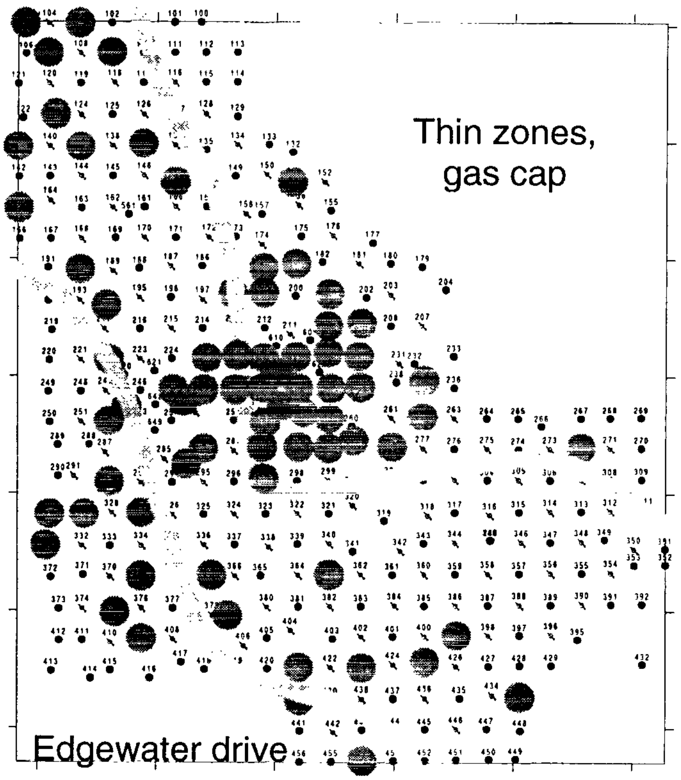


Fig. 7.– Wells that have symptoms of poor reservoir conformance are marked by a large circle.

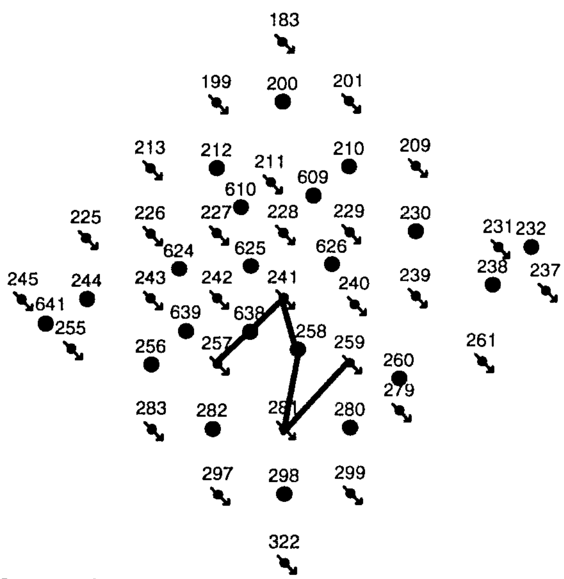


Fig. 8.– Conformance diamond. The "Z" indicates the conformance cross section shown in **Fig. 3.**

Treatment design. Three different treatment designs were applied in the conformance diamond depending on the problem type, the well condition, and the reservoir features. These three treatment types were cement squeezes for abandoning the gas cap and high-permeability streaks, a polymer gelant for deep penetration into matrix, and a flowing gel for treating natural fractures. A treatment matrix was developed for selecting different cement slurries and gel types depending on injectivity tests, zonal isolation, and wellbore conditions (see **Table 1** at the end of the text). Cement squeeze treatments were used when an areally extensive vertical barrier isolated an overprocessed zone from adjacent target zones. A near wellbore abandonment was sufficient in such a case. The gelant was applied when there was communication in the reservoir between the layer being treated and adjacent zones *and* matrix flow was evident. The flowing gel was applied when linear flow behavior was evident.

The procedure detailed below is one of the polymer treatment designs. The procedure begins by stimulating the zones targeted for production (including acid wash of zones targeted for polymer treatment), followed by a polymer gel treatment for in-depth zone abandonment, and finally, a cement squeeze treatment for near-wellbore isolation of the zones containing polymer.

Two different polyacrylamide chrome acetate crosslinked systems were available at the wellsite (see **Table 1**). System 1 had a 24-hr working time (can penetrate matrix for 24 hours), used an intermediate molecular weight polymer with a low degree of hydrolysis, and was for wells that exhibit radial flow characteristics, (**Fig. 9**). System 2 was a preformed gel that used a high molecular weight polymer with a high degree of hydrolysis. System 2 was for wells that exhibit linear flow characteristics. Both systems used 0.5% polymer by weight.

1. Collect required execution data:
   a) Tubing packer depth/displacement volume.
   b) BHST
   c) BHSIP
   d) Maximum BHP/STP.
2. Acidize wash the target interval with approximately 20 gal/ft HCl to insure good injectivity.
3. Set a retainer below the zone targeted for shutoff and acid stimulate the zones below the retainer (use foam for acid diversion).
4. Determine the conformance treatment placement technique (use the placement technique selection guide in SPE 38325).[2]
5. Employ appropriate placement technique (the remaining steps are for mechanical isolation of an upper zone, protecting the lower zones).
6. Plugback with a packer and sand topped with a $CaCO_2$ pill.
7. Move in and rig up the mixing and pumping equipment.
8. Hydrate the polymer in the mixing equipment.
9. Pressure test lines.
10. Begin injectivity test.
    a) Inject System 1 at one bbl/min.
    b) Monitor injectivity decline.
    c) If injectivity decline is that of radial flow (**Fig. 9**), continue treatment with System 1 until design volume criteria are met.

   d) If injectivity decline is that of linear flow (**Fig. 9**), switch to System 2 and pump until design volume criteria are met.
11. Continue monitoring injectivity decline for duration of treatment.
12. Go to flush when either of the design volume criteria in a) or b) is met, or when both conditions in c) and d) are met.
   a) total design volume has been pumped
   b) injection rate falls below 0.2 bbls/min at the maximum injection pressure (just below fracturing pressure).
   c) Condition 1: Monitor and plot injectivity (*IJ*) vs. cumulative volume injected. Condition 1 is met when IJ falls to 0.5 BPD/PSI, where: $IJ = BPD / (BHTP - P_{res})$
   d) Condition 2: Monitor and plot resistance factor (*RF*) versus cumulative volume injected. Condition 2 is met when RF > 7.0, where: $RF = IJ_{init} / IJ_{trtg}$ and $IJ_{init} = BPD_{init} / (BHTP_{init} - P_{res})$, and $IJ_{trtg} = BPD_{trtg} / (BHTP_{trtg} - P_{res})$
13. Flush to tubing packer with System 1 or 2 without the crosslinker when job is done (low pH crosslinker retards cement).
14. Rig down gel mixing and pumping equipment.
15. Shut in until ready for cement squeeze (cement cap was applied to provide near-wellbore strength). Minimize the shut in time between the end of the polymer treatment and the start of the cement squeeze.
16. Take precautions to avoid breaking down the formation during the cement squeeze.
17. The wells with polymer System 1 will be shut in for 72-hrs after the polymer treatment. System 2 only requires a 24-hr shut-in.
18. Drill out cement and plugs.
19. Inspect pumps, tubulars, and wellhead equipment. Reinstall production or injection strings.
20. Return to production or injection slowly. Start at 100 bbls/day and increase over a 72-hr period.

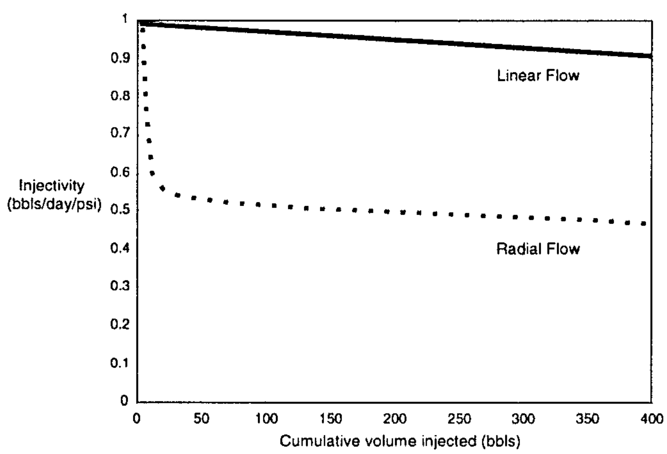


Fig. 9.– Location injectivity test verifies flow geometry.

Results

Thirty one workovers have been executed in the conformance diamond to date. The wells treated include 22 injection wells and 7 production wells. A summary of the treatments is given in **Table 2** (at the end of the text). The injection well treatment results are shown in **Table 3** and the production well treatment results are shown in **Table 4**.

Production response. The work in the conformance diamond began in March 1997 and extended through April 1998. **Figure 10** shows the combined water production, oil production, and water injection in the conformance diamond. The change in the WOR slope in 1994 indicates the onset of serious water cycling. Production changes due to injection well treatments take many months to occur because the underprocessed zones in associated patterns must fill up and pressurize before maximum waterflood response is observed. However, preliminary results show an increase in oil production with decreasing water injection, water production, and WOR.

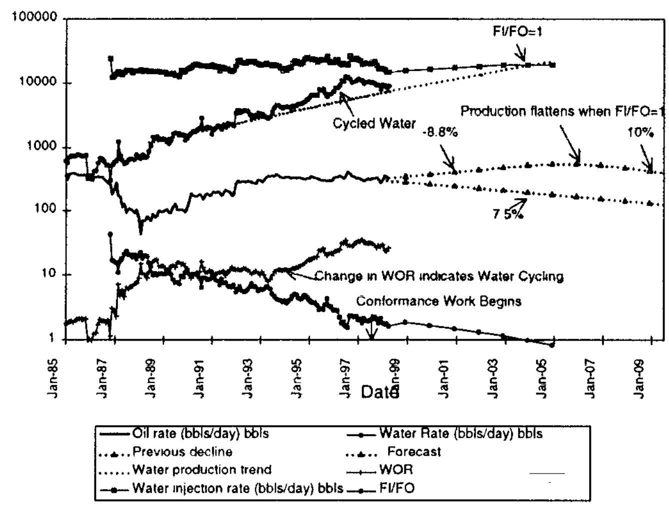


Fig. 10.– Production in the conformance diamond.

The following wells showed a rapid production response following treatment:

1. EMSU 638 production doubled following a workover that shut off the gas cap and stimulated low-pressure zones. Additionally, each of the surrounding injectors had shutoff treatments to eliminate injection into the gas cap.
2. Emsu 238 had a 30% production increase following a Zone 6 plugback, stimulation of the productive zones, and injector conformance work in the surrounding injection wells.
3. EMSU 610 had a 50% production increase as a result of gas cap shutoff treatments in offset injectors.
4. EMSU 609 production increased 30% immediately following a shutoff treatment on offset injection well 211.

5. EMSU 212 had a 60% production increase a few months after gas cap shut-off treatments in an offset injector.
6. EMSU 282 production dropped sharply following an injector conformance treatment on EMSU 257 (may not be related), and then rebounded following a clean out and stimulation treatment on EMSU 282 in January.

Economic Analysis. Decline curve analysis shows an incremental recovery from preliminary results. The base oil rate decline prior to the conformance project was 7.5% during 1996. The current incline in oil production is -8.8% which matches the same incline prior to water cycling in 1990 and 1991. The projected forecast for response extrapolates out the current incline until a FI/FO ratio of 1 is reached in 2004. Production then flattens out for 2 years and assumes a 10% decline which is 2.5 times the prewaterflood decline. Subtracting off the 7.5% base decline yields an incremental 1.9 million barrels of oil. The associated economics for this conservative forecast are shown in **Table 5**. The maximum upside potential is believed to be bound by the initial waterflood incline of -34% (1988-1991).

Implementation challenges. There were some problems during the execution of the conformance diamond well workovers. One common problem was behind pipe communication due to poor cement bonding (presumably due to previous acid treatments and aging wellbores), which made achieving the designed acid and cement placement difficult. Polymer treatments were not used in wells that had behind pipe communication because the desired zonal isolation could not be achieved. Isolation was also difficult in open-hole wellbores due to rugose hole conditions and wash-outs around the casing shoe. Due to behind pipe communication and open-hole conditions, sand was used along with a cast iron bridge plug or an inflate to plugback wells in order to protect the target zones from cement or gel. Crossflows caused significant problems when trying to plugback with sand. Low bottom hole pressures and thief zones also caused problems when plugging back, and made it difficult to circulate, clean-out, and gather good diagnostic data during injectivity tests. Another problem was that despite the best diagnostic efforts, some wells contained larger than expected thief zones that hindered the effectiveness of the shutoff treatment. EMSU 259 and EMSU 239 are examples of this problem and mulitple cement squeezes were required to shut off the offending zones. Other problems included squeeze jobs that leaked and the failure of some casing and tubing strings that were weakened by corrosion. It was difficult to get a good cement bond when iron sulfide scale was present. One best practice developed was to acid wash the perforations and open-hole before the squeeze in order to get a better bond. Another best practice was to perform the cement squeeze after the target zones were acid stimulated. This practice increased the success rate of cement squeezes.

Summary

A focused reservoir conformance improvement project was conducted for a section of the Eunice Monument South Unit. The project goals were to increase oil production and reduce water cycling in 16 contiguous patterns called the conformance diamond.

The first phase of the project entailed reservoir characterization. The characterization identified several items that cause waterflood conformance problems. The problem items included the existence of areally extensive high permeability streaks, water injection into the gas cap (and high permeability streaks in the gas cap), and the presence of natural fractures.

Wellbore treatments were designed to eliminate water injection into the gas cap and stimulate water injection and oil production from the underprocessed zones. Cement squeezes were applied when there was a barrier isolating the thief zone from the rest of the pay. Gel treatments were applied to achieve deep penetration into matrix or fractures.

The water injection rate into the gas cap was reduced by 85% and the oil production rate has increased by 16% as of March 1998. It is too soon after the completion of the project to give a full evaluation of the program's economic impact.

Notation

BHST	bottomhole static temperature [F]
BHSIP	bottomhole shut-in pressure [psi]
$BHTP_{init}$	initial bottomhole treating pressure [psi]
$BHTP_{trtg}$	bottom hole treating pressure during treatment [psi]
BPD_{init}	initial injection rate [bbl/day]
BPD_{trtg}	injection rate during treatment [bbl/day]
DPI	discounted profitability index [$/$]
FI/FO	fluid in / fluid out of the reservoir [bbls/bbls]
IJ	injectivity [bbl/D/psi]
IJ_{init}	initial injectivity [bbl/D/psi]
IJ_{trtg}	injectivity during treatment [bbl/D/psi]
NPV	net present value [$millions]
P_{res}	reservoir pressure [psi]
RF	resistance factor
S_{wi}	irreducible water saturation
S_{or}	residual oil saturation
S_{gr}	residual gas saturation
WOR	water / oil ratio [bbls/bbls]

Acknowledgments

The authors extend sincere thanks to those whose cooperation facilitated compilation of the case history presented here. Chevron USA of Midland, TX donated the bullhead injection case history; Texaco of Midland, TX donated the dual injection case history. Thanks are also given to Schlumberger and Chevron USA for permission to present this information.

References

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2. Miller, M. J., and Chan, K. S.: "Water Control Gel Placement," *SPE 38325, presented at the 1997 SPE Western Regional Meeting,* June 25-27, 1997.

SI Metric Conversion Factors

cp x 1.0*E-03	= Pa.s
ft x 3.048*E-01	= m
°F x (°F-32)/1.8	= °C
in. x 2.54*E+00	= cm
lbm x 4.535924*E-01	= kg
md x 9.869233*E-04	= μm^2
psi x 6.894757*E+00	= kPa

*Conversion factor is exact.

Table 1.–Treatment selection matrix.

Injectivity		Cement Squeeze		Polymer Squeeze	
bpm	psi	Slurry 1	Slurry 2	System 1	System 2
1	600-900	X			
2	300-600	X	X		
3	100-300		X	X	
4	0-100			X	X
5	0			X	X

Cement Slurry 1: Low fluid loss cement with expanding agent to improve bond.
Cement Slurry 2: Thixotropic, low fluid loss cement to aid in early squeeze pressure; foamed with 250 scf/bbl N_2.
Polymer System 1: Intermediate molecular weight polymer with low degree of hydrolysis and 24-hr working time.
Polymer System 2: High molecular weight polymer with high degree of hydrolysis.

Table 2.–Treatment summary for conformance focus area.

Well	Date Treated	Type	Treatment	Notes
EMSU 183	Nov-97	injector	squeeze Z1-2, perforate Z3, acidize Z3-5	squeeze only tested to 380 psi
EMSU 199	Nov-97	injector	squeeze Z1-2, acidize Z3-5	good squeeze; some backside communication during acid job
EMSU 201	Sep-97	injector	perf Z3, acidize wellbore, squeeze Z6	
EMSU 209	10/97	injector	squeeze Z2, acidize Z3-5	squeeze only tested to 430 psi, bled 150 psi in 10 min
EMSU 211	Mar-97	injector	386 bbl MARCIT Z2, clean out and stimulate Z3-5	design 1500 bbl MARCIT; acid job broke into SA Z6
	May-98	injector	squeeze Z6, stimulate Z3-5	1 yr old MARCIT and cement leaked, several 100 psi in 5 min
EMSU 212	Nov-97	producer	squeeze Z1-2, stimulate Z3-5	
EMSU 225	Nov-97	injector	squeeze Z1, stimulate Z2-4	squeeze leaked; 555 psi to zero in 25 min
EMSU 226	Jul-97	injector	squeeze Z1, stimulate Z2-4	possible casing problem; very slight squeeze leak
EMSU 227	Jul-97	injector	squeeze Z1-2, stimulate Z3-5; add perforations	casing split during acid job (after squeeze)
EMSU 228	Jun-97	injector	squeeze Z1-2, stimulate Z3-TD	
EMSU 229	May-97	injector	squeeze Z1-2, add perforations, stimulate Z3-TD	squeeze bled 80 psi in 10 min
EMSU 237	Oct-97	injector	add perforations in Z3-4, stimulate Z3-5 (not completed in Z1-2)	
EMSU 238	Jan-98	producer	plug back to 3830 ft, stimulate openhole (3748-3830 ft)	
EMSU 239	Sep-97	injector	MARCIT/cement Z1-2, add perforations Z3-4, stimulate Z3-5	all perforations communicated during acid job; did not use MARCIT, only cement
EMSU 240	Jun-97	injector	squeeze Z1-2, stimulate Z3-TD	squeezed perforations leaked 500 psi to 0 in 5 min; acid job had behind pipe communication
EMSU 241	Jun-97	injector	squeeze Z1-2, stimulate openhole	test squeeze to 500 psi; lost 450 psi in 11 min.
EMSU 242	Jul-97	injector	squeeze Z1-2, stimulate openhole	test squeeze to 500 psi; no pressure loss
EMSU 243	Sep-97	injector	squeeze Z1, stimulate openhole	did not test squeeze
EMSU 244	Oct-97	producer	add perforations in Z2, plugback Z4 and lower Z3, stimulate Z1-upper Z3	
EMSU 245	Feb-98	injector	clean out and stimulate	
EMSU 255	Feb-98	injector	clean out and stimulate	could not get coiled tubing into hole, no clean out and stimulation
	Apr-98	injector	clean out and stimulate	
EMSU 257	Oct-97	injector	1060 bbl MARCIT/cement Z1-2, stimulate Z2a-5	communication during acid job, test squeeze to 315 psi; no bleed off
EMSU 258	Apr-98	producer	add perforations in Z3-4, stimulate Z3-4, squeeze Z1-2	test squeeze to 400 psi, no bleed-off
EMSU 259	Jan-98	injector	MARCIT/cement Z2, stimulate Z3-5	acid stimulation, then had well problems; tried several cement squeezes, finally successful; no MARCIT
EMSU 638	Dec-97	producer	add perforations, stimulate Z3-4, squeeze Z2	acid communicated behind pipe; test squeeze to 500 psi, no pressure loss
EMSU 261	Dec-97	injector	add perforations, stimulate Z3-5, squeeze Z1-2	had to repair casing leak before acid job; looks like squeeze perforations leaked a bit
EMSU 279	Dec-97	injector	stimulate Z3-5, squeeze Z2 and casing shoe	behind pipe communication during acid job; test squeeze to 500 psi; bled to 300 psi in 30 min
EMSU 280	Nov-97	producer	stimulate Z3-4	behind pipe communication during acid job
EMSU 282	Jan-98	producer	cleanout and stimulate	behind pipe communication during acid job

Table 3.–Injection well treatments through February 1998 for conformance diamond.

Well	Date Treated	% Injection into the Gas Cap		Injectivity (B/D/psi)	
		Before	After	Before	After
EMSU 183	Nov-97	79%	0%	0.34	0.32
EMSU 199	Nov-97	76%	0%	0.64	0.35
EMSU 201	Sep-97	45% Z6	0%Z6	0.58	0.08
EMSU 209	10/97	53%	0%	vacuum	vacuum
EMSU 211	Mar-97	72%	100% Z6	1.56	0.55
	May-98	100%Z6	no results yet		
EMSU 225	Nov-97	100%	38%	0.41	0.36
EMSU 226	Jul-97	42%	0%	0.98	0.7
EMSU 227	Jul-97	68%	21%	4.8	1.6
EMSU 228	Jun-97	21%	0%	0.65	0.9
EMSU 229	May-97	100%	19%	5	0.9
EMSU 237	Oct-97	0%	0%	0.6	1.3
EMSU 239	Sep-97	73%	17%	1.5	0.4
EMSU 240	Jun-97	68%	33%	1.7	1.2
EMSU 241	Jun-97	100%	0%	1.1	1
EMSU 242	Jul-97	87%	42%	1	1.3
EMSU 243	Sep-97	68%	10%	0.54	0.3
EMSU 245	Feb-98	well distributed	little change	1	no results yet
EMSU 255	Feb-98	well distributed	little change	1.08	no results yet
	Apr-98				no results yet
EMSU 257	Oct-97	100%	0%	1.2	0.4
EMSU 259	Jan-98	100%	0%	6	2
EMSU 261	Dec-97	50%	0%	0.97	0.39
EMSU 279	Dec-97	100%	0%	0.8	0.53

Table 4.–Production well treatments through February 1998 for conformance diamond.

Well	Date Treated	Water Production Rate (BWPD)		Oil Production Rate (BOPD)	
		Before	After	Before	After
EMSU 212	Nov-97	960	1170	13	13
EMSU 238	Jan-98	320	420	20	26
EMSU 244	Oct-97	155	161	14	12
EMSU 258	Apr-98	870	no results yet	2	no results yet
EMSU 638	Dec-97	1400	163	33	58
EMSU 280	Nov-97	370	390	11	11
EMSU 282	Jan-98	400	600	30	27

Table 5.–Preliminary economics.

Preliminary Economics	
24 jobs to date	$43,000 / job
Total investment	1.0 MM$
After tax NPV @ 10%	1.8 MM$
Reserves	1.9 MMBO
% OOIP	2.1%
Rate of return	56%
DPI @ 10% discount	4.7
Payout	42 months

REBUTTAL EXHIBIT B-52

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

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO. COMM. CASE NO. 24123

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO, DIV. CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO. DIV. CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY LEA COUNTY, NEW MEXICO.
DIV. CASE NOS. 24018-24020
24025

VIDEO DEPOSITION OF JAMES BUCHWALTER
December 13, 2024
9:00 a.m.
Via Zoom

PURSUANT TO THE FEDERAL RULES OF CIVIL PROCEDURE, this deposition was:

TAKEN BY: ADAM G. RANKIN, ESQ.
ATTORNEY FOR GOODNIGHT MIDSTREAM

REPORTED BY: KENDRA D. TELLEZ, RMR-CRR-RPR
Kendra Tellez Court Reporting, Inc.
A Veritext Company
Suite 105
500 4th Street, Northwest
Albuquerque, New Mexico 87102

But on the pressures, because your modeling -- as I understand, your modeling here is from basically the -- first production, right? This -- this model starts from first production, correct?

A. Correct. Correct. Because that's going to create the most accurate model possible.

Q. And to do so, when you talk about pressures, you're going to need to know what -- or get as close as you can to understanding what the original reservoir pressure is, correct?

A. Correct.

Q. And because we're dealing with multiple formations, you're going to need -- you're going to want to know as best you can what the original reservoir pressures are for each of the subject formations, correct?

A. Correct.

Q. Okay. And those -- that's one of -- the number one drivers that would influence your -- your modeling, correct?

A. Correct.

Q. Okay. Number two is geology. Now, what do you mean by geology? What -- what kind of -- what input are you relying on or do you need to

data and the saltwater disposal data.
Q. Okay. I want to walk through those separately. And that -- and that data on the producing wells, the 638 producing and injection wells -- when I say "injection wells" here, I'm talking about the waterflood injection wells. Okay?
A. Correct.
Q. That goes back to the beginning of production data?
A. Correct.
Q. What data -- that goes back to, what, 1938; is that right?
A. Correct.
Q. Okay. So that's the start date for your model?
A. Yes. As I said earlier, to have the most accurate model possible, you want to go back to day one and -- if possible and then run the model forward from that time. That would give you the best model currently that you could possibly have, so . . .
Q. The question that I have is: Why -- why did you include the EMSU and the EMSU-B in the same model as the AGU?
A. The reason is, because I realized that

Empire.
Q. Okay. But my question is: You did not -- based on what information you got, you did not extend -- you did not see any need to extend the Grayburg grid beyond what's depicted on this exhibit?
A. No, I did not. The maps I was given, clearly there wasn't water coming in from -- from the west, so I didn't have to extend the grid there. And I've been told that the sand diminishes in quality as we move to the east, and that's why we didn't have wells there.
So I basically used the area with -- that encompassed basically the 600-odd wells to -- and that's the -- the maps I was given, so . . .
Q. What was your -- what was -- what information allowed you to decide that there was not water coming in from the west in the Grayburg?
A. Well, that -- there's a Chevron report in the late '80s that states that this is a solution drive reservoir, that the bottom of the Grayburg did produce some water. But in addition to that, the San Andres had to be communicating with the Grayburg. And the proof in that is that oil is lighter than -- excuse me -- oil is lighter than

the EMSU in the center part of the map, and the AGU to the south. Okay? And this is based off of OCD data as of May 22, 2024. Okay?

The legend shows the different saltwater disposal operators. Each one of these, based on OCD data, is completed and injecting into the San Andres. This my representation to you. Okay?

A. Okay.

Q. Based on my review and what you and I just walked through on your Exhibit E-1, I'm just -- I'm just asking you whether or not you're aware of some of these wells that were excluded and if you can tell me, if you know, why.

The first one is the Parker Energy SWD Number 5. And that's this one over here. It's just to the southeast of the EMSU and just to the north of the AGU. And it's directly to the south of two of the wells that you have included on your map and presumably in your model. Here, if you can see my -- my cursor, it's sort of right between the AGU and EMSU right here in this section.

Do you see that it's not showing up there and you don't have the Parker as a category on your legend?

A. Yeah. As -- as I said, I -- I integrate the data that I've been given. I don't QC the data. That's the responsibility of Empire. And so --

Q. Okay.

A. If you have some wells that we don't have in here, then first we'll have to look in our database and see -- see if they were included in the model. And if not, if these -- do these wells in total produce a significant amount of -- or inject a significant amount of saltwater disposal water?

Q. Well, these are -- these show the total cumulative injection volumes. And my understanding is that you want to have an accurate model, so you want to have all the data included, correct?

A. Yeah. We can always include this data and update the model and see if it makes any difference.

Q. Okay. So the Parker, based on the OCD data, has a cumulative injection volume of a little over 8 million barrels as of --

A. Okay.

Q. -- May 2024. Okay?

A. Okay.

Q. The other well, I think, that I don't see on your map -- or operator is this VM Henderson, which is a southwest royalties well, but I think you may have it represented up here in the green arrow

A. And -- essentially, it's a subsea, but then they've corrected it for the -- for -- based on the basis from the -- I guess, maybe from the average depth of the surface to where the reservoir is.

So, you know, some of these sands might be 3500 to 4,000 feet. Well, reality is that they're all corrected with the same subsea correction to get that to the subsea depth, so . . .

It's based on -- you can -- you can think of it as based on TVD, but it's basically all corrected from subsea down based on a certain number. And I can't remember what that number is exactly, but I think it might be in the -- in the -- in the document here somewhere.

Q. Okay. I guess what I'm trying to get at is, I just want -- I'm trying to understand what -- what elevations each model layer is -- is assigned. Okay? Does that make sense?

A. Yeah. Well, it varies, of course, from where you are in the structure, in any one of these individual layers.

Q. And the model incorporates the structure you were given by Empire, correct?

A. That's exactly correct, yes.

layers because this is helpful. You know, I guess everybody slices and dices the Grayburg in different ways. Dr. Lindsey, who is one of Empire's witnesses, I think he's got maybe seven layers. I've seen six layers. Here, I think you've done five.

To your knowledge, do the layers you -- you've built into your model correspond to any other set of -- anybody else's approach or theory about how to -- how to divide the Grayburg?

A. Well, the more -- there are two reasons to divide it into layers. One, geology might change vertically and, you know, is given different ranges for porosity in different parts of the Grayburg. So that's one reason to divide a model up, just to get the geology more accurate.

The other reason to divide sand up into multiple layers is to just get better representation of the physics so that the gas might -- you know, the fluids will migrate and you'll have a more accurate representation of where the fluids are in any one point of this reservoir, so . . .

Q. So you keep using the words --

A. It didn't have one cell that gets through the Grayburg. It might have -- you know, who knows?

all three areas in the San Andres?
A. I think they are, yes.
Q. Okay. Since we're on this graph, 894 million barrels original oil-in-place, where did that number come from?
A. That -- that came from a history match where -- where -- as I said earlier, if you understand the production that's being produced in time and if you understand what the outreach reservoir pressure, how it changes in time. From material balance perspective and a physics perspective, you can then use that to back out how much oil-water-gas we have in these two respective sands. We have water in the San Andres.
Q. Okay. I'm going to ask that later, follow up on that.
And then the 90 (sic) million barrels of residual oil, where did that number come from?
A. That was given to me by Empire, and they said the ROZ had 900 million barrels underneath the Empire leases, so I put that in.
Q. Do you know where that -- other than coming from Empire, do you know the basis for that?
A. No, I do not. I was just given that number, and I put in. I assume it came from core

little bit on the oil-in-place, but the ultimate model and the ultimate water moving into the sand from the San Andres to the Grayburg is really dependent on the shortcomings we have in water production in the Grayburg. And that's -- that's something that's more or less independent of what's going on in the San Andres. We just have to represent the San Andres slightly different to get it all to fit.

Q. Now, we talked about this a little bit, and I want -- I want to come back to it now, I guess. The -- you told me that you did multiple runs of this model. I don't know, 200 or 300 or more model runs, right, to try to get a history match?

A. On this -- on this computer, I got 366, and on another computer probably a couple hundred, so -- it was -- this was a very, very challenging model to get everything to fit because we have lots of data and a number of things that we had to adjust to get everything to fit.

Q. How long have you been working on putting the model together?

A. This is probably as hard a model as I've ever had to tackle. This model takes somewhere

A. -- in the wells.
Q. Even if you -- even if you expanded the -- the size of the Grayburg, you couldn't match?
A. Well, I was given maps, and I -- within those -- those maps, I put a contact in there and -- yeah, unless the Grayburg's got an aquifer that goes out 36 miles, and we can see that that's not the case. Because if we look at the cumulative water-oil ratio map in 1986, it showed that if the Grayburg had water, it wasn't coming from someplace 36 miles away to the west, for example, in deeper sands.
That water was coming up from the bottom somehow, even in the Grayburg. And that water wasn't enough to match the production in the Grayburg without putting these leaks between the Grayburg and the San Andres at well locations that produce high oil-water ratios.
Q. So those maps that you were given, were they provided to us as part of the production that you prepared?
A. Probably not. I -- I don't know.
Q. It sounds like you're relying on --
A. And maybe they were. I -- I don't -- I don't know. I mean, that wasn't -- you know,

foundation.
A. I don't do log analysis. The only thing I can tell you, as I said earlier, is that the water had to come from the bottom. It couldn't come from the Grayburg that I had mapped. It had to come -- not just from a -- from the bottom, but it had to come from sand at the bottom. It goes out 30-something miles, and we can clearly see from the cumulative water-oil ratio map in 1986, that that water wasn't coming into the Grayburg wells on the western side of the reservoir, so . . .
Q. Well, I understand.
A. And you can do this, but the -- but the data and the maps show that the water was coming from the San Andres.
Q. So what I want to -- I understand that's -- that's what you're saying. But I also understand that you told me from the beginning that understanding the original reservoir pressure in modeling the pressure correctly is key to making your model run properly, right?
A. Yeah, correct. But, I mean, you move -- you move the -- the -- yeah, if you move it down a little bit in the model, still it's under the same pressure in the San Andres. That's not changing the

we -- we can maybe quibble about, you know, some of the decimal places there, based on the TDS, or whatever. But assuming that's a reasonable pressure gradient, okay, for this reservoir, okay, I agree with you that we would be able to calculate a pressure at depths just doing the math, right?

A. Correct.

Q. Okay. But that -- my point to you is that -- that calculation to -- to come up with a deeper pressure at a deeper depth is -- is -- assumes that -- that there's not a differential in pressure between -- along the way, somewhere going down in depth, correct?

A. Well, assuming sands -- some sands aren't overpressured, the gradient is going to stay comparably the same. Of course, when you go through an oil sand, the gradient is going to change a little bit potentially.

Q. Or under-pressured, right?

A. It could. I mean, generally, the -- in most normal situations, the .43 gradient in any reservoir is very reasonable.

Q. But this is -- a reminder, Dr. Buchwalter, this is a carbon reservoir, right?

A. Okay. It's a carbonate reservoir.

year 2040, we've got hundreds of pounds higher pressure in the San Andres underneath the Grayburg than we do at the limits of the reservoir, so it's . . .

Q. Okay. But my question is --

A. It's just a big aquifer.

Q. In real life, right?

A. Yeah.

Q. And your model has it out -- going out 36 miles. So it's -- it's bigger than that in real life, right?

A. Well, in real life, it -- I mean, it -- it -- that size aquifer and that volume of aquifer fits the production in pressures.

Q. Why didn't you build a model aquifer going out to the east or south or any other direction?

A. Well, my understanding from Empire was if we moved it to the east, the sand degrades. And the thing that's -- that's more -- I mean, honestly, I don't know exactly the dimensions of the aquifer. It could be different dimensioned, but the key is getting -- because it's a pretty incompressible fluid, if we look at the big picture trying to get about the right answer, the key is getting that volume in. And I knew that the structure dipped, I

A. It's a -- it's a combination of permeability and relative permeability. They were both adjusted to get things to fit.

Q. And you can't -- it's not -- you can't simply tell me, right? You -- you need to give me the curve to understand that, right?

A. Yeah, I could give you the curve, but -- you know, it's a curve that fit the historical production data.

And part of what that curve does is, it's making adjustments for the fact that, you know, I put one permeability in the sand, but in addition, there may be high perm streaks where water is just shooting through the -- and things aren't uniform the way things are moving.

And we actually adjust those relative permeability curves so that the combination, the permeability and the relative permeability can allow us to get better estimates and better fits of, let's say, historical gas-oil ratios and water-oil ratios, so . . .

And, for example, if you increase the -- let's say the residual oil saturation, the water-oil, that's -- it makes less mobile oil, right? And if -- if we have a very low permeability

Spring will produce more water per barrel of oil, if that's a way to express it as a ratio, and the Wolfcamp does.

Q. Is it higher TDS, or is it still -- they're both kind of comparable?

A. I think there's a broad range there. There's a lot of change of grade, but in a true generality, the Bone Spring salinity will be higher.

Q. Thank you.

EXAMINER GOETZE: My turn?

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Just a quick question: Do you know where you are relative to the reef -- the Capitan Reef?

A. We are approximately three-and-a-half to four miles east of the reef.

Q. Very good.

EXAMINER GOETZE: No more questions.

MR. RANKIN: Thank you, Mr. Examiner.

With that, I'll move on to the next.

EXAMINER GOETZE: The one I'm working on, 22.

MR. RANKIN: Yeah. We'll catch up here.

Q. (BY MR. RANKIN) Mr. Drake, will you please find before you the exhibit packet for Case Number 20722?

Q. And I would make one request. In your Exhibit 8A, though we have a very nice diagram of where the edge of the Ogallala is, could we have the source of that presentation so it can be referenced? Your lawyer can provide it at a later time.

A. Yes.

MR. RANKIN: You just want to know --

EXAMINER GOETZE: A big blue blob on a piece of paper is not really a very good exhibit, so -- and particularly with the USGS interpretation and Maddis' [sic; phonetic] work. So let's clarify that, please.

MR. RANKIN: Okay.

Q. (BY EXAMINER GOETZE) And then I'm going to throw out one more conversation. With regards to the interaction between the San Andres and the Capitan Reef, any conjecture as to any possibility of this having an impact farther downdip to the reef structure?

A. I believe we're six miles away from the reef, if not more, at this location. We're going to talk about other sites today. I don't think we have a hydraulic communication to the reef or that we will be affecting it at this point in time.

Q. Well, there's already been a billion barrels of water put in this area, the stuff I've come up with in

our records with Rice Engineering alone. So we do have concerns, and that's typically why we request the water sampling, so we can see what we do have is considered protectable and nonprotectable. So if you are going to move forward with this well, we would certainly ask that water sampling be done. We have that obligation.

But other than that, your presentation is good.

EXAMINER GOETZE: I have no further questions for this witness.

MR. RANKIN: Mr. Examiner, just to clarify, you're requesting to collect water samples at the injection interval zones, spots?

EXAMINER GOETZE: Yeah. What we're going to do is any -- you have the HESS paper, the outflow -- the Hobbs outflow, and it's changed direction, I'm sure. And we've been looking at it because we promised in our primacy that we would monitor the water quality. HESS map's at less than 10,000. It is the Division's opportunity to revisit it. And when we drill new wells, we've moved away from open hole. We don't like that anymore because we know at some point, we're going to have to cap these wells. And we're also sampling so that when the EPA comes back to us, through our exempt aquifer program, that we have successfully looked at it and have qualified locations.

There's an SPE paper on overpressurization of the San Andres. So we're looking at a large-scale operation here, and we understand there is a depletion, and we're moving things around. So it is best to collect data at the beginning of the story and not have regrets later, especially when they come and ask us to shut the program so that we can go back and look at the exempt aquifers, as what happened in the state of California.

So your presentation is good, and we have a better understanding about what you're doing, but this is something you're going to have to get familiar with. Okay?

MR. RANKIN: I'm sure they will.

Thank you, Mr. Examiner.

With that, no further questions. Call our next witness.

EXAMINER GOETZE: Please.

MR. RANKIN: Call Mr. Tomastik.

THOMAS E. TOMASTIK,

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

MS. LUCK: Yeah, thank you. I want to just mention Mr. Drake did include his hydrologic statement as D-2 with his affidavit in both of these cases. And he does not believe that there is any connection between any underground sources of drinking water and this injection well.

TECHNICAL EXAMINER COSS: Yes. I appreciate that, Ms. Luck.

HEARING OFFICER BRANCARD: Mr. Rose-Coss, is there anything in addition that you would like to see in this application?

TECHNICAL EXAMINER COSS: Well, this application is one of half a dozen or more similar applications in the vicinity. And the Division had some concern there could be potential for these injected waters to migrate into not the drinking water sources, the shallow drinking water sources, but the potential to protectable waters within the Capitan Reef and has not seen any modeling by All or Goodnight to suggest that these waters won't eventually -- the injected waters won't eventually migrate towards the Capitan Reef and potentially impact the protectable waters within the Capitan Reef that the statute requires to protect.

So any one of these wells in solo, standalone, doesn't necessarily pose a threat, but the Division is considering their impact in toto. That's a statement for the record, and if Goodnight or All would like to provide modeling to such an extent, the Division would be pleased to see it.

MS. LUCK: Thank for letting us know. I appreciate that explanation.

TECHNICAL EXAMINER COSS: Yeah.

HEARING OFFICER BRANCARD: And Mr. Rose-Coss, for this interval, this is San Andres, are we -- do we -- does the Division normally look for a fault slip potential, also?

TECHNICAL EXAMINER COSS: The Division is less concerned with the potential for fault slip for the San Andres, but the San Andres is known to have communication due to its stratigraphic position with the Capitan Reef formation.

HEARING OFFICER BRANCARD: Okay.

TECHNICAL EXAMINER COSS: It doesn't communicate with the basin like the Devonian, but it will communicate with the Capitan Reef.

HEARING OFFICER BRANCARD: Thank you. So we will take this case then, 21570, and accept the exhibits and take it under advisement with the proviso that there may be further communication from the Division on these cases on that. Is that acceptable, Ms. Luck?

MS. LUCK: Thank you. I appreciate it.

HEARING OFFICER BRANCARD: Okay.

From: Nathan Alleman
To: Coss, Dylan
Cc: Grant Adams; Steve Drake - Retired; KALuck@hollandhart.com
Subject: Goodnight - Andre Dawson and Ernie Banks Capitan Reef Proximity
Date: Sunday, January 24, 2021 10:06:40 PM

[EXTERNAL EMAIL NOTIFICATION] This message was received from outside the Goodnight Midstream Organization, do not click links or attachments unless you recognize the sender and know the content is safe.

Dylan,

Goodnight's attorney, Ms. Kaitlyn Luck, mentioned that at last week's hearings for Goodnight's Andre Dawson SWD #1 (Case No. 21569) and Ernie Banks SWD #1 (Case No. 21570) OCD asked about the proximity of the proposed SWD locations to the Capitan Reef. OCD did not specifically request that Goodnight follow up with information related to this request, but as a means of resolving this concern, we have provided the distance from each proposed SWD location to the nearest point of the Capitan Reef.

- **Andre Dawson SWD #1:** 3.2 miles to the closest point of the Capitan Reef
- **Ernie Banks SWD #1:** 2.8 miles to the closest point of the Capitan Reef

Additionally, the Capitan Reef is shallower than the proposed injection formation (San Andres) and there is stratigraphic separation between the San Andres and Capitan Reef formations. Based on both the geographic distance and stratigraphic separation, these wells pose no threat of adverse impact to the water quality in the Capitan Reef.

Please let us know if you have any further questions on this.

Regards,

Nate Alleman
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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 GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

CASE NO. 20555
ORDER NO. R-20855

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on June 14, 2019, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze.

NOW, on this 12th day of September 2019, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and the subject matter.

(2) Goodnight Midstream Permian, LLC ("Applicant" or "Goodnight Midstream") seeks authority to utilize its Nolan Ryan SWD Well No. 1 (API No. 30-025-45349; the "Subject Well"), located 779 feet from the South line and 1995 feet from the East line (Unit O) of Section 13, Township 21 South, Range 36 East, NMPM, Lea County, New Mexico, for disposal of produced water into the San Andres formation through a perforated interval from 4100 feet to 4700 feet below surface.

(3) Goodnight Midstream submitted a Division Form C-108 application (Administrative Application No. pMAM1907048843) on March 3, 2019, for authority to inject into the Subject Well which was protested by the New Mexico State Land Office ("SLO") and Parker Energy Services, Inc.

(4) On May 14, 2019, Goodnight Midstream submitted an application for hearing for approval of the Subject Well for commercial disposal of produced water.

(5) Subsequently, the SLO filed an entry of appearance for this application on May 28, 2019.

(6) Applicant appeared at the hearing through counsel and presented geologic and engineering evidence to the effect that:

(a) The Applicant seeks to drill the Subject Well to an approximate total depth of 4800 feet below surface. The injection will occur through perforations from approximately 4100 feet to approximately 4700 feet below surface.

(b) The Subject Well will be constructed with the following two casing strings: a 9⅝-inch surface casing set at 1350 feet and a 7-inch production casing set from the surface to 4800 feet. Both casings will have cement circulated to the surface.

(c) The Subject Well will inject fluids through 4½-inch, fiberglass-lined steel tubing attached to a packer set at depth at or within 100 feet of the shallowest perforation.

(d) The primary sources of produced water will be production from wells completed in the Bone Spring and the Wolfcamp formations.

(e) The analyses of produced water samples provided by Applicant showed the compatibility of the injection fluids with formation fluids in the proposed disposal interval.

(f) The Applicant proposes the Subject Well as a commercial operation with a maximum average injection rate of 15000 barrels of water per day (BWPD) using a maximum surface injection pressure of 820 pounds per square inch (psi).

(g) The depth of the deepest known source of fresh water in the vicinity of the Subject Well was approximately 200 feet below surface and was identified as the Rustler formation.

(h) Three active fresh-water wells were identified within a one-mile radius of the Subject Well. The Applicant provided water quality analyses for the three wells that showed total dissolved solid (TDS) concentrations less than 400 milligrams per liter (mg/L) in each case.

(i) Applicant stated the Subject Well is greater than six miles from the Capitan Reef aquifer and that there is no evidence of hydrologic communication between the reef and the proposed injection interval.

(j) Applicant's engineering witness testified that he has examined the available geological and engineering data and found no evidence of open faults or any other hydrologic connection between the disposal zone and any underground sources of drinking water.

(k) The results of the one half-mile Area of Review (AOR) around the Subject Well found one active well that penetrated the proposed injection interval. The well, Parker Energy SWD No. 5 (API 30-025-38789), is properly cased and cemented as to protect underground sources of drinking water and not allow migration of injected fluids from the proposed injection interval.

(l) Applicant identified the San Andres formation for the disposal interval due to the high porosity and the absence of historical hydrocarbon production in the formation within a two-mile radius of the Subject Well.

(m) Applicant further stated the top of the San Andres formation contains several anhydrite intervals that provide an upper confining layer for the proposed disposal interval while the low porosity rocks of the lower San Andres and upper Glorieta formations provide a lower confining layer.

(n) Applicant has recently completed disposal wells in the same interval of the San Andres formation as proposed for the Subject Well and found the formation to be pressure depleted owing to large-scale water extraction used to support prior enhanced recovery and drilling operations.

(o) The Applicant provided evidence of notification of this application to all "*affected persons*" within a one half-mile radius of the surface location of the Subject Well and with publication in a newspaper of general circulation in the county.

(7) The SLO appeared through counsel at hearing and did not oppose the granting of this application. The SLO provided a statement into record expressing their concern for the spacing of disposal wells and the potential impacts to adjacent state mineral interests.

(8) No other party appeared at the hearing, or otherwise opposed the granting of this application.

The Division concludes as follows:

(9) The application has been duly filed under provisions of Rule 19.15.26.8 NMAC.

(10) Geologic and engineering interpretations submitted by the Applicant identified geologic seals at the top and at the base of the proposed disposal zone that would prevent the vertical migration of injection fluids.

(11) The disposal fluids are compatible with existing formation fluids based on analytical results provided by Applicant.

(12) The application has been duly filed under the provisions of Division Rule 19.15.26.8 NMAC.

(13) Applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met.

(14) Division records indicate Goodnight Midstream (OGRID 372311) as of the date of this order is in compliance with Division Rule 19.15.5.9 NMAC.

(15) Approval of disposal in the Subject Well will enable Applicant to support existing production and future exploration in this area, thereby preventing waste, and will not impair correlative rights.

IT IS THEREFORE ORDERED THAT:

(1) Goodnight Midstream Permian, LLC (the "operator") is hereby authorized to utilize its Nolan Ryan SWD Well No. 1 (API No. 30-025-45349; the "Subject Well"), located 779 feet from the South line and 1995 feet from the East line (Unit O) of Section 13, Township 21 South, Range 36 East, NMPM, Lea County, New Mexico, for disposal of Underground Injection Control Class II fluids into the San Andres formation.

(2) Disposal shall be through a perforated interval from 4100 feet to 4700 feet below surface comprising the San Andres formation only. Injection is to be through 4½-inch, plastic-lined tubing with a packer set within 100 feet above the top perforation of the permitted interval.

(3) The operator shall take all steps necessary to ensure that the disposed water enters only the permitted disposal interval and is not permitted to escape to other formations or onto the surface.

(4) Well construction and testing shall be in accordance with Division Rule 19.15.16 NMAC and all casing strings shall have cement circulated to surface. If cement does not circulate on any casing string, the operator shall run a cement bond log (CBL) or other log to determine top of cement and shall notify the Division's District I office with the top of cement on the emergency phone number prior to continuing with any further cement activity with the Subject Well. If cement did not tie back in to next higher casing shoe, the operator shall perform remedial cement job to bring cement, at a minimum, 200 feet above the next higher casing shoe.

(5) After installation of tubing, the casing-tubing annulus shall be loaded with an inert fluid and equipped with a pressure gauge or an approved leak detection device in order to determine leakage in the casing, tubing, or packer. The casing shall be pressure tested from the surface to the packer setting depth to assure casing integrity.

(6) The operator shall run a mudlog over the approved disposal interval for assessment of the hydrocarbon potential and obtain a water sample for analysis of hydrocarbon content as well as general water chemistry (including major cations, major anions, and Total Dissolved Solids (TDS)). Prior to commencing injection, the operator shall supply the results of the water sample and the mudlog to Division's District I office and provide a copy of the same submittal to Engineering Bureau in the Santa Fe office. *If the analysis of the sample is found to contain a TDS concentration of 10000 mg/L or less, the injection authority under this Order shall be suspended ipso facto*.

(7) The Subject Well shall pass an initial mechanical integrity test ("MIT") prior to commencing disposal and prior to resuming disposal each time the well has significant equipment changes including, but not limited to, the packer being unseated, tubing being pulled, or when casing repairs have occurred. The operator shall notify the Division's District I office a minimum of 48 hours in advance of the proposed date and time of the modification of disposal equipment and of any MIT test so that the same may be inspected and witnessed. All MIT procedures and schedules shall follow the requirements in Division Rule 19.15.26.11(A) NMAC.

(8) The operator shall file a Notice of Intent on Division Form C-103 with the Division's District I office prior to any testing of the well or for any activities that shall modify the well construction or operation. The operator shall provide written notice of the date of commencement of disposal to the Division's District I office. The operator shall submit monthly reports of the disposal operations on Division Form C-115, in accordance with Division Rules 19.15.26.13 NMAC and 19.15.7.24 NMAC.

(9) If the Subject Well fails a MIT or if there is evidence that the mechanical integrity of said well is impacting correlative rights, the public health, any underground sources of fresh water, or the environment, the Division Director shall require the Subject Well to be shut-in within 24 hours of discovery and the operator shall redirect all disposal waters to another facility. The operator shall take the necessary actions to address the impacts resulting from the mechanical integrity issues in accordance with Division Rule 19.15.26.10 NMAC, and the Subject Well shall be tested pursuant to Rule 19.15.26.11 NMAC prior to returning to injection.

(10) Without limitation on the duties of the operator as provided in Rules 19.15.29 NMAC and 19.15.30 NMAC, or otherwise, the operator shall immediately notify the Division's District I office of any failure of the tubing, casing or packer in the Subject Well, or of any leakage or release of water, oil or gas from or around any produced or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

(11) The wellhead injection pressure on the Subject Well shall be limited to **no more than 820 psi**. The disposal well shall be equipped with a pressure limiting device in workable condition which shall, at all times, limit surface tubing pressure to the maximum allowable pressure for this well. The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(12) The Director of the Division may authorize an increase in tubing pressure upon a proper showing by the operator of said well that such higher pressure will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an acceptable Step-Rate Test.

(13) The injection authority granted under this order is not transferable except upon Division approval. The Division may require the operator to demonstrate mechanical integrity of any injection well that will be transferred prior to approving transfer of authority to inject.

(14) The Division may revoke this injection permit after notice and hearing if the operator is in violation of Division Rule 19.15.5.9 NMAC.

(15) The disposal authority granted herein shall terminate one (1) year after the effective date of this order if the operator has not commenced injection operations into the Subject Well. The Division, upon written request by the operator prior to the termination date, may grant an extension thereof for good cause.

(16) One (1) year after disposal into the Subject Well has ceased, the well will be considered abandoned and the authority to dispose will terminate *ipso facto* as provided in Division Rule 19.15.26.12(C) NMAC.

(17) Compliance with this order does not relieve the operator of the obligation to comply with other applicable federal, state or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety and the environment.

(18) Jurisdiction is retained by the Division for the entry of such further orders as may be necessary for the prevention of waste and/or protection of correlative rights or upon failure of the operator to conduct operations (1) to protect fresh or protectable waters or (2) consistent with the requirements in this order; whereupon the Division may, after notice and hearing or prior to notice and hearing in event of an emergency, terminate the disposal authority granted herein.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

ADRIENNE SANDOVAL
Director

SEAL

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 GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

CASE NO. 20556
ORDER NO. R-20863

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on June 14, 2019, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze.

NOW, on this 17th day of September 2019, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and the subject matter.

(2) Cases No. 20556 and 20557 were consolidated at the hearing for the purpose of testimony; however, a separate order will be issued for each case.

(3) In Case No. 20556, Goodnight Midstream Permian, LLC ("Applicant" or "Goodnight Midstream") seeks authority to utilize its Robinson SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well"), located 1868 feet from the North line and 1564 feet from the West line (Unit F) of Section 4, Township 22 South, Range 36 East, NMPM, Lea County, New Mexico, for disposal of produced water into the Glorieta formation through an open-hole interval from 5750 feet to 6500 feet below surface.

(4) Goodnight Midstream submitted a Division Form C-108 application (Administrative Application No. pMAM1911552448) on April 18, 2019, for authority to inject into the Subject Well which was protested by the New Mexico State Land Office ("SLO") and Blackbeard Operating, LLC ("Blackbeard").

(5) On May 14, 2019, Goodnight Midstream submitted an application for hearing for approval of the Subject Well for disposal of produced water.

(6) Subsequently, the SLO filed an entry of appearance for this application on May 28, 2019 and Blackbeard filed an entry of appearance for this application on June 7, 2019.

(7) Applicant appeared at the hearing through counsel and presented geologic and engineering evidence to the effect that:

(a) The Applicant seeks to drill the Subject Well to an approximate total depth of 6600 feet below surface. The injection will occur through open hole completion from approximately 5750 feet to approximately 6500 feet below surface.

(b) The Subject Well will be constructed with the following two casing strings: a 9⅝-inch surface casing set at 495 feet and a 7-inch production casing set from the surface to 5750 feet. Both casings will have cement circulated to the surface. Additionally, the well will have a 16-inch surface conductor casing that will be cemented from surface.

(c) The Subject Well will inject fluids through 4½-inch, fiberglass-lined steel tubing attached to a packer set at depth at or within 100 feet of the top of the open-hole completion.

(d) The primary sources of produced water will be production from wells completed in the Bone Spring and the Wolfcamp formations.

(e) The analyses of produced water samples provided by Applicant showed the compatibility of the injection fluids with formation fluids in the proposed disposal interval.

(f) The Applicant proposes the Subject Well as a commercial operation with a maximum average injection rate of 12500 barrels of water per day (BWPD) using a maximum surface injection pressure of 1150 pounds per square inch (psi).

(g) The depth of the deepest known source of fresh water in the vicinity of the Subject Well was identified as the Rustler formation with the lower contact approximately 470 feet below surface.

(h) Three fresh-water wells were identified within a one-mile radius of the Subject Well. The Applicant attempted to obtain water samples from each water well but field inspections found the wells inoperative, and therefore, samples could not be collected.

(i) Applicant stated the Subject Well is located approximately 150 feet southwest of the proposed Scully SWD No. 1 which is to be completed in the shallower San Andres formation and is the subject of Case No. 20557.

(j) Applicant's engineering witness testified that he has examined the available geological and engineering data and found no evidence of open faults or any other hydrologic connection between the disposal zone and any underground sources of drinking water.

(k) The results of the one half-mile Area of Review (AOR) around the Subject Well found no active or plugged wells that penetrated the proposed injection interval.

(l) Applicant identified the Glorieta formation for the disposal interval due to the high porosity and the absence of historical hydrocarbon production in the formation within a two-mile radius of the Subject Well. Applicant has recently completed a disposal well in the same interval and found the formation favorable for disposal at the proposed rates of injection.

(m) Applicant further identified approximately 400 feet of tight limestone in the lower San Andres formations that will provide a confining layer for the top of the proposed injection interval in the Glorieta formation while the contact with the stratigraphic equivalent of the Paddock formation formed a lower confining layer.

(n) The Applicant provided evidence of notification of this application to all "*affected persons*" within a one half-mile radius of the surface location of the Subject Well and with publication in a newspaper of general circulation in the county.

(8) The SLO appeared through counsel at hearing and did not oppose the granting of this application. The SLO provided a statement into record expressing their concern for the spacing of disposal wells and the potential impacts to adjacent state mineral interests.

(9) Blackbeard appeared through counsel at hearing and did not oppose the granting of this application.

(10) No other party appeared at the hearing, or otherwise opposed the granting of this application.

The Division concludes as follows:

(11) The application has been duly filed under provisions of Rule 19.15.26.8 NMAC.

(12) Geologic and engineering interpretations submitted by the Applicant identified geologic seals at the top and at the base of the proposed disposal zone that would prevent the vertical migration of injection fluids.

(13) The disposal fluids are compatible with existing formation fluids based on analytical results provided by Applicant.

(14) Based on the testimony offered at hearing, the well's location with respect to the Capitan Reef aquifer, and to assist in future plugging under Rule 19.15.16.9 NMAC, the Division shall stipulate a well design change to have the production casing set to total depth and injection to occur through perforation of that casing.

(15) The application has been duly filed under the provisions of Division Rule 19.15.26.8 NMAC.

(16) Applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met.

(17) Division records indicate Goodnight Midstream (OGRID 372311) as of the date of this order is in compliance with Division Rule 19.15.5.9 NMAC.

(18) Approval of disposal in the Subject Well will enable Applicant to support existing production and future exploration in this area, thereby preventing waste, and will not impair correlative rights.

IT IS THEREFORE ORDERED THAT:

(1) Goodnight Midstream Permian, LLC (the "operator") is hereby authorized to utilize its Robinson SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well"), located 1868 feet from the North line and 1564 feet from the West line (Unit F) of Section 4, Township 22 South, Range 36 East, NMPM, Lea County, New Mexico, for disposal of Underground Injection Control Class II fluids into the Glorieta formation.

(2) Disposal shall be through a perforated interval from 5750 feet to 6500 feet below surface comprising the Glorieta formation only. Injection is to be through 4½-inch, plastic-lined tubing with a packer set within 100 feet above the top perforation of the permitted interval.

(3) The 7-inch production casing shall be set to the total depth of the borehole and shall have cement circulated to surface. Injection shall be through perforations

(4) The operator shall take all steps necessary to ensure that the disposed water enters only the permitted disposal interval and is not permitted to escape to other formations or onto the surface.

(5) Well construction and testing shall be in accordance with Division Rule 19.15.16 NMAC and all casing strings shall have cement circulated to surface. If cement does not circulate on any casing string, the operator shall run a cement bond log (CBL) or other log to determine top of cement and shall notify the Division's District I office with the top of cement on the emergency phone number prior to continuing with any further cement activity with the Subject Well. If cement did not tie back in to next higher casing shoe, the operator shall perform remedial cement job to bring cement, at a minimum, 200 feet above the next higher casing shoe.

(6) After installation of tubing, the casing-tubing annulus shall be loaded with an inert fluid and equipped with a pressure gauge or an approved leak detection device in order to determine leakage in the casing, tubing, or packer. The casing shall be pressure tested from the surface to the packer setting depth to assure casing integrity.

(7) The operator shall run a mudlog over the approved disposal interval for assessment of the hydrocarbon potential and obtain a water sample for analysis of hydrocarbon content as well as general water chemistry (including major cations, major anions, and Total Dissolved Solids (TDS)). Prior to commencing injection, the operator shall supply the results of the water sample and the mudlog to Division's District I office and provide a copy of the same submittal to Engineering Bureau in the Santa Fe office. *If the analysis of the sample is found to contain a TDS concentration of 10000 milligrams per liter or less, the injection authority under this Order shall be suspended ipso facto.*

(8) The Subject Well shall pass an initial mechanical integrity test ("MIT") prior to commencing disposal and prior to resuming disposal each time the well has significant equipment changes including, but not limited to, the packer being unseated, tubing being pulled, or when casing repairs have occurred. The operator shall notify the Division's District I office a minimum of 48 hours in advance of the proposed date and time of the modification of disposal equipment and of any MIT test so that the same may be inspected and witnessed. All MIT procedures and schedules shall follow the requirements in Division Rule 19.15.26.11(A) NMAC.

(9) The operator shall file a Notice of Intent on Division Form C-103 with the Division's District I office prior to any testing of the well or for any activities that shall modify the well construction or operation. The operator shall provide written notice of the date of commencement of disposal to the Division's District I office. The operator shall submit monthly reports of the disposal operations on Division Form C-115, in accordance with Division Rules 19.15.26.13 NMAC and 19.15.7.24 NMAC.

(10) If the Subject Well fails a MIT or if there is evidence that the mechanical integrity of said well is impacting correlative rights, the public health, any underground sources of fresh water, or the environment, the Division Director shall require the Subject Well to be shut-in within 24 hours of discovery and the operator shall redirect all disposal waters to another facility. The operator shall take the necessary actions to address the impacts resulting from the mechanical integrity issues in accordance with Division Rule 19.15.26.10 NMAC, and the Subject Well shall be tested pursuant to Rule 19.15.26.11 NMAC prior to returning to injection.

(11) Without limitation on the duties of the operator as provided in Rules 19.15.29 NMAC and 19.15.30 NMAC, or otherwise, the operator shall immediately notify the Division's District I office of any failure of the tubing, casing or packer in the Subject Well, or of any leakage or release of water, oil or gas from around any produced or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

(12) The wellhead injection pressure on the Subject Well shall be limited to **no more than 1150 psi**. The disposal well shall be equipped with a pressure limiting device in workable condition which shall, at all times, limit surface tubing pressure to the maximum allowable pressure for this well. The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(13) The Director of the Division may authorize an increase in tubing pressure upon a proper showing by the operator of said well that such higher pressure will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an acceptable Step-Rate Test.

(14) The injection authority granted under this order is not transferable except upon Division approval. The Division may require the operator to demonstrate mechanical integrity of any injection well that will be transferred prior to approving transfer of authority to inject.

(15) The Division may revoke this injection permit after notice and hearing if the operator is in violation of Division Rule 19.15.5.9 NMAC.

(16) The disposal authority granted herein shall terminate one (1) year after the effective date of this order if the operator has not commenced injection operations into the Subject Well. The Division, upon written request by the operator prior to the termination date, may grant an extension thereof for good cause.

(17) One (1) year after disposal into the Subject Well has ceased, the well will be considered abandoned and the authority to dispose will terminate *ipso facto* as provided in Division Rule 19.15.26.12(C) NMAC.

(18) Compliance with this order does not relieve the operator of the obligation to comply with other applicable federal, state or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety and the environment.

(19) Jurisdiction is retained by the Division for the entry of such further orders as may be necessary for the prevention of waste and/or protection of correlative rights or upon failure of the operator to conduct operations (1) to protect fresh or protectable waters or (2) consistent with the requirements in this order; whereupon the Division may, after notice and hearing or prior to notice and hearing in event of an emergency, terminate the disposal authority granted herein.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

ADRIENNE SANDOVAL
Director

S E A L

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 GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

CASE NO. 20557
ORDER NO. R-20864

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on June 14, 2019, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze.

NOW, on this 17th day of September 2019, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and the subject matter.

(2) Cases No. 20556 and 20557 were consolidated at the hearing for the purpose of testimony; however, a separate order will be issued for each case.

(3) In Case No. 20557, Goodnight Midstream Permian, LLC ("Applicant" or "Goodnight Midstream") seeks authority to utilize its Scully SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well"), located 1724 feet from the North line and 1607 feet from the West line (Unit F) of Section 4, Township 22 South, Range 36 East, NMPM, Lea County, New Mexico, for disposal of produced water into the San Andres formation through an open-hole interval from 5750 feet to 6500 feet below surface.

(4) Goodnight Midstream submitted a Division Form C-108 application (Administrative Application No. pMAM1911551157) on April 18, 2019, for authority to inject into the Subject Well which was protested by the New Mexico State Land Office ("SLO") and Blackbeard Operating, LLC ("Blackbeard").

(5) On May 14, 2019, Goodnight Midstream submitted an application for hearing for approval of the Subject Well for disposal of produced water.

(6) Subsequently, the SLO filed an entry of appearance for this application on May 28, 2019 and Blackbeard filed an entry of appearance for this application on June 7, 2019.

(7) Applicant appeared at the hearing through counsel and presented geologic and engineering evidence to the effect that:

(a) The Applicant seeks to drill the Subject Well to an approximate total depth of 5750 feet below surface. The injection will occur through open hole completion from approximately 4450 feet to approximately 5750 feet below surface.

(b) The Subject Well will be constructed with the following two casing strings: a 9⅝-inch surface casing set at 495 feet and a 7-inch production casing set from the surface to 4450 feet. Both casings will have cement circulated to the surface. Additionally, the well will have a 16-inch surface conductor casing that will be cemented from surface.

(c) The Subject Well will inject fluids through 4½-inch, fiberglass-lined steel tubing attached to a packer set at depth at or within 100 feet of the top of the open-hole completion.

(d) The primary sources of produced water will be production from wells completed in the Bone Spring and the Wolfcamp formations.

(e) The analyses of produced water samples provided by Applicant showed the compatibility of the injection fluids with formation fluids in the proposed disposal interval.

(f) The Applicant proposes the Subject Well as a commercial operation with a maximum average injection rate of 17500 barrels of water per day (BWPD) using a maximum surface injection pressure of 890 pounds per square inch (psi).

(g) The depth of the deepest known source of fresh water in the vicinity of the Subject Well was identified as the Rustler formation with the lower contact approximately 470 feet below surface.

(h) Three fresh-water wells were identified within a one-mile radius of the Subject Well. The Applicant attempted to obtain water samples from each water well but field inspections found the wells inoperative, and therefore, samples could not be collected.

(i) Applicant stated the Subject Well is located approximately 150 feet northeast of the proposed Robinson SWD No. 1 which is to be completed in the deeper Glorieta formation and is the subject of Case No. 20556.

(j) Applicant's engineering witness testified that he has examined the available geological and engineering data and found no evidence of open faults or any other hydrologic connection between the disposal zone and any underground sources of drinking water.

(k) The results of the one half-mile Area of Review (AOR) around the Subject Well found no active or plugged wells that penetrated the proposed injection interval.

(l) Applicant identified the San Andres formation for the disposal interval due to the high porosity and the absence of historical hydrocarbon production in the formation within a two-mile radius of the Subject Well.

(m) Applicant further stated the top of the San Andres formation contains several anhydrite intervals that provide an upper confining layer for the proposed disposal interval while the low porosity rocks of the lower San Andres and upper Glorieta formations provide a lower confining layer.

(n) The Applicant provided evidence of notification of this application to all "*affected persons*" within a one half-mile radius of the surface location of the Subject Well and with publication in a newspaper of general circulation in the county.

(8) The SLO appeared through counsel at hearing and did not oppose the granting of this application. The SLO provided a statement into record expressing their concern for the spacing of disposal wells and the potential impacts to adjacent state mineral interests.

(9) Blackbeard appeared through counsel at hearing and did not oppose the granting of this application.

(10) No other party appeared at the hearing, or otherwise opposed the granting of this application.

<u>The Division concludes as follows:</u>

(11) The application has been duly filed under provisions of Rule 19.15.26.8 NMAC.

(12) Geologic and engineering interpretations submitted by the Applicant identified geologic seals at the top and at the base of the proposed disposal zone that would prevent the vertical migration of injection fluids.

(13) The disposal fluids are compatible with existing formation fluids based on analytical results provided by Applicant.

(14) Based on the testimony offered at hearing, the well's location with respect to the Capitan Reef aquifer, and to assist in future plugging under Rule 19.15.16.9 NMAC, the Division shall stipulate a well design change to have the production casing set to total depth and injection to occur through perforation of that casing.

(15) The application has been duly filed under the provisions of Division Rule 19.15.26.8 NMAC.

(16) Applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met.

(17) Division records indicate Goodnight Midstream (OGRID 372311) as of the date of this order is in compliance with Division Rule 19.15.5.9 NMAC.

(18) Approval of disposal in the Subject Well will enable Applicant to support existing production and future exploration in this area, thereby preventing waste, and will not impair correlative rights.

IT IS THEREFORE ORDERED THAT:

(1) Goodnight Midstream Permian, LLC (the "operator") is hereby authorized to utilize its Scully SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well"), located 1724 feet from the North line and 1607 feet from the West line (Unit F) of Section 4, Township 22 South, Range 36 East, NMPM, Lea County, New Mexico, for disposal of Underground Injection Control Class II fluids into the San Andres formation.

(2) Disposal shall be through a perforated interval from 4450 feet to 5750 feet below surface comprising the San Andres formation only. Injection is to be through 4½-inch, plastic-lined tubing with a packer set within 100 feet above the top perforation of the permitted interval.

(3) The 7-inch production casing shall be set to the total depth of the borehole and shall have cement circulated to surface. Injection shall be through perforations

(4) The operator shall take all steps necessary to ensure that the disposed water enters only the permitted disposal interval and is not permitted to escape to other formations or onto the surface.

(5) Well construction and testing shall be in accordance with Division Rule 19.15.16 NMAC and all casing strings shall have cement circulated to surface. If cement does not circulate on any casing string, the operator shall run a cement bond log (CBL) or other log to determine top of cement and shall notify the Division's District I office with the top of cement on the emergency phone number prior to continuing with any further cement activity with the Subject Well. If cement did not tie back in to next higher casing shoe, the operator shall perform remedial cement job to bring cement, at a minimum, 200 feet above the next higher casing shoe.

(6) After installation of tubing, the casing-tubing annulus shall be loaded with an inert fluid and equipped with a pressure gauge or an approved leak detection device in order to determine leakage in the casing, tubing, or packer. The casing shall be pressure tested from the surface to the packer setting depth to assure casing integrity.

(7) The operator shall run a mudlog over the approved disposal interval for assessment of the hydrocarbon potential and obtain a water sample for analysis of hydrocarbon content as well as general water chemistry (including major cations, major anions, and Total Dissolved Solids (TDS)). Prior to commencing injection, the operator shall supply the results of the water sample and the mudlog to Division's District I office and provide a copy of the same submittal to Engineering Bureau in the Santa Fe office. *If the analysis of the sample is found to contain a TDS concentration of 10000 milligrams per liter or less, the injection authority under this Order shall be suspended ipso facto.*

(8) The Subject Well shall pass an initial mechanical integrity test ("MIT") prior to commencing disposal and prior to resuming disposal each time the well has significant equipment changes including, but not limited to, the packer being unseated, tubing being pulled, or when casing repairs have occurred. The operator shall notify the Division's District I office a minimum of 48 hours in advance of the proposed date and time of the modification of disposal equipment and of any MIT test so that the same may be inspected and witnessed. All MIT procedures and schedules shall follow the requirements in Division Rule 19.15.26.11(A) NMAC.

(9) The operator shall file a Notice of Intent on Division Form C-103 with the Division's District I office prior to any testing of the well or for any activities that shall modify the well construction or operation. The operator shall provide written notice of the date of commencement of disposal to the Division's District I office. The operator shall submit monthly reports of the disposal operations on Division Form C-115, in accordance with Division Rules 19.15.26.13 NMAC and 19.15.7.24 NMAC.

(10) If the Subject Well fails a MIT or if there is evidence that the mechanical integrity of said well is impacting correlative rights, the public health, any underground sources of fresh water, or the environment, the Division Director shall require the Subject Well to be shut-in within 24 hours of discovery and the operator shall redirect all disposal waters to another facility. The operator shall take the necessary actions to address the impacts resulting from the mechanical integrity issues in accordance with Division Rule 19.15.26.10 NMAC, and the Subject Well shall be tested pursuant to Rule 19.15.26.11 NMAC prior to returning to injection.

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(11) Without limitation on the duties of the operator as provided in Rules 19.15.29 NMAC and 19.15.30 NMAC, or otherwise, the operator shall immediately notify the Division's District I office of any failure of the tubing, casing or packer in the Subject Well, or of any leakage or release of water, oil or gas from around any produced or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

(12) The wellhead injection pressure on the Subject Well shall be limited to **no more than 890 psi**. The disposal well shall be equipped with a pressure limiting device in workable condition which shall, at all times, limit surface tubing pressure to the maximum allowable pressure for this well. The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(13) The Director of the Division may authorize an increase in tubing pressure upon a proper showing by the operator of said well that such higher pressure will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an acceptable Step-Rate Test.

(14) The injection authority granted under this order is not transferable except upon Division approval. The Division may require the operator to demonstrate mechanical integrity of any injection well that will be transferred prior to approving transfer of authority to inject.

(15) The Division may revoke this injection permit after notice and hearing if the operator is in violation of Division Rule 19.15.5.9 NMAC.

(16) The disposal authority granted herein shall terminate one (1) year after the effective date of this order if the operator has not commenced injection operations into the Subject Well. The Division, upon written request by the operator prior to the termination date, may grant an extension thereof for good cause.

(17) One (1) year after disposal into the Subject Well has ceased, the well will be considered abandoned and the authority to dispose will terminate *ipso facto* as provided in Division Rule 19.15.26.12(C) NMAC.

(18) Compliance with this order does not relieve the operator of the obligation to comply with other applicable federal, state or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety and the environment.

(19) Jurisdiction is retained by the Division for the entry of such further orders as may be necessary for the prevention of waste and/or protection of correlative rights or upon failure of the operator to conduct operations (1) to protect fresh or protectable waters or (2) consistent with the requirements in this order; whereupon the Division may, after notice and hearing or prior to notice and hearing in event of an emergency, terminate the disposal authority granted herein.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

ADRIENNE SANDOVAL
Director

SEAL

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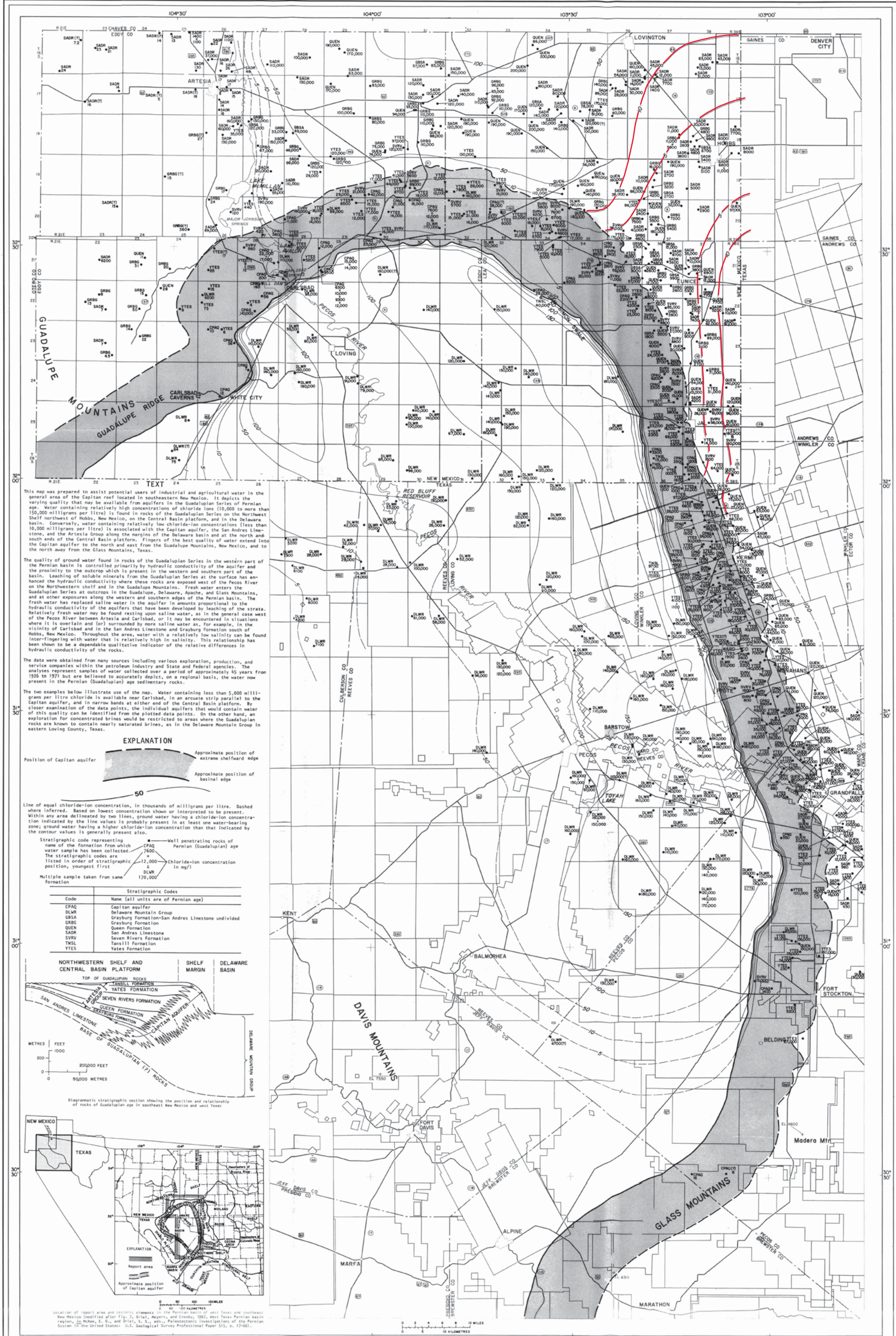
NEW MEXICO STATE ENGINEER

RESOURCE MAP 4



TEXT

This map was prepared to assist potential users of industrial and agricultural water in the general area of the Capitan reef located in southeastern New Mexico. It depicts the varying quality that may be available from aquifers in the Guadalupian Series of Permian age. Water containing relatively high concentrations of chloride ions (10,000 to more than 150,000 milligrams per litre) is found in rocks of the Guadalupian Series on the Northwest Shelf northwest of Hobbs, New Mexico, on the Central Basin platform, and in the Delaware basin. Conversely, water containing relatively low chloride-ion concentrations (less than 10,000 milligrams per litre) is associated with the Capitan aquifer, the San Andres Limestone, and the Artesia Group along the margins of the Delaware basin and at the north and south ends of the Central Basin platform. Fingers of the best quality of water extend into the Capitan aquifer to the north and east from the Guadalupe Mountains, New Mexico, and to the north away from the Glass Mountains, Texas.

The quality of ground water found in rocks of the Guadalupian Series in the western part of the Permian basin is controlled primarily by hydraulic conductivity of the aquifer and the proximity to the outcrop which is present in the western and southern part of the basin. Leaching of soluble minerals from the Guadalupian Series at the surface has enhanced the hydraulic conductivity where these rocks are exposed west of the Pecos River on the Northwestern shelf and in the Guadalupe Mountains. Fresh water enters the Guadalupian Series at outcrops in the Guadalupe, Delaware, Apache, and Glass Mountains, and at other exposures along the western and southern edges of the Permian basin. The fresh water has replaced saline water in the aquifer in amounts proportional to the hydraulic conductivity of the aquifers that have been developed by leaching of the strata. Relatively fresh water may be found resting upon saline water, as in the general case west of the Pecos River between Artesia and Carlsbad, or it may be encountered in situations where it is overlain and (or) surrounded by more saline water as, for example, in the vicinity of Carlsbad and in the San Andres Limestone and Grayburg Formation south of Hobbs, New Mexico. Throughout the area, water with a relatively low salinity can be found inter-fingering with water that is relatively high in salinity. This relationship has been shown to be a dependable qualitative indicator of the relative differences in hydraulic conductivity of the rocks.

The data were obtained from many sources including various exploration, production, and service companies within the petroleum industry and State and Federal agencies. The analyses represent samples of water collected over a period of approximately 45 years from 1926 to 1971 but are believed to accurately depict, on a regional basis, the water now present in the Permian (Guadalupian) age sedimentary rocks.

The two examples below illustrate use of the map. Water containing less than 5,000 milligrams per litre chloride is available near Carlsbad, in an arcuate strip parallel to the Capitan aquifer, and in narrow bands at either end of the Central Basin platform. By closer examination of the data points, the individual aquifers that would contain water of this quality can be identified from the plotted data points. On the other hand, an exploration for concentrated brines would be restricted to areas where the Guadalupian rocks are known to contain nearly saturated brines, as in the Delaware Mountain Group in eastern Loving County, Texas.

EXPLANATION

Position of Capitan aquifer

Approximate position of extreme shelfward edge

Approximate position of basinal edge

50

Line of equal chloride-ion concentration, in thousands of milligrams per litre. Dashed where inferred. Based on lowest concentration shown or interpreted to be present. Within any area delineated by two lines, ground water having a chloride-ion concentration indicated by the line values is probably present in at least one water-bearing zone; ground water having a higher chloride-ion concentration than that indicated by the contour values is generally present also.

Stratigraphic code representing name of the formation from which water sample has been collected. The stratigraphic codes are listed in order of stratigraphic position, youngest first

Multiple sample taken from same formation

CPAQ
7600
+
12,000
&
DLWR
170,000

Well penetrating rocks of Permian (Guadalupian) age

Chloride-ion concentration in mg/l

	Stratigraphic Codes
Code	Name (all units are of Permian age)
CPAQ	Capitan aquifer
DLWR	Delaware Mountain Group
GBSA	Grayburg Formation-San Andres Limestone undivided
GRBG	Grayburg Formation
QUEN	Queen Formation
SADR	San Andres Limestone
SVRV	Seven Rivers Formation
TNSL	Tansill Formation
YTES	Yates Formation

Diagrammatic stratigraphic section showing the position and relationship of rocks of Guadalupian age in southeast New Mexico and west Texas

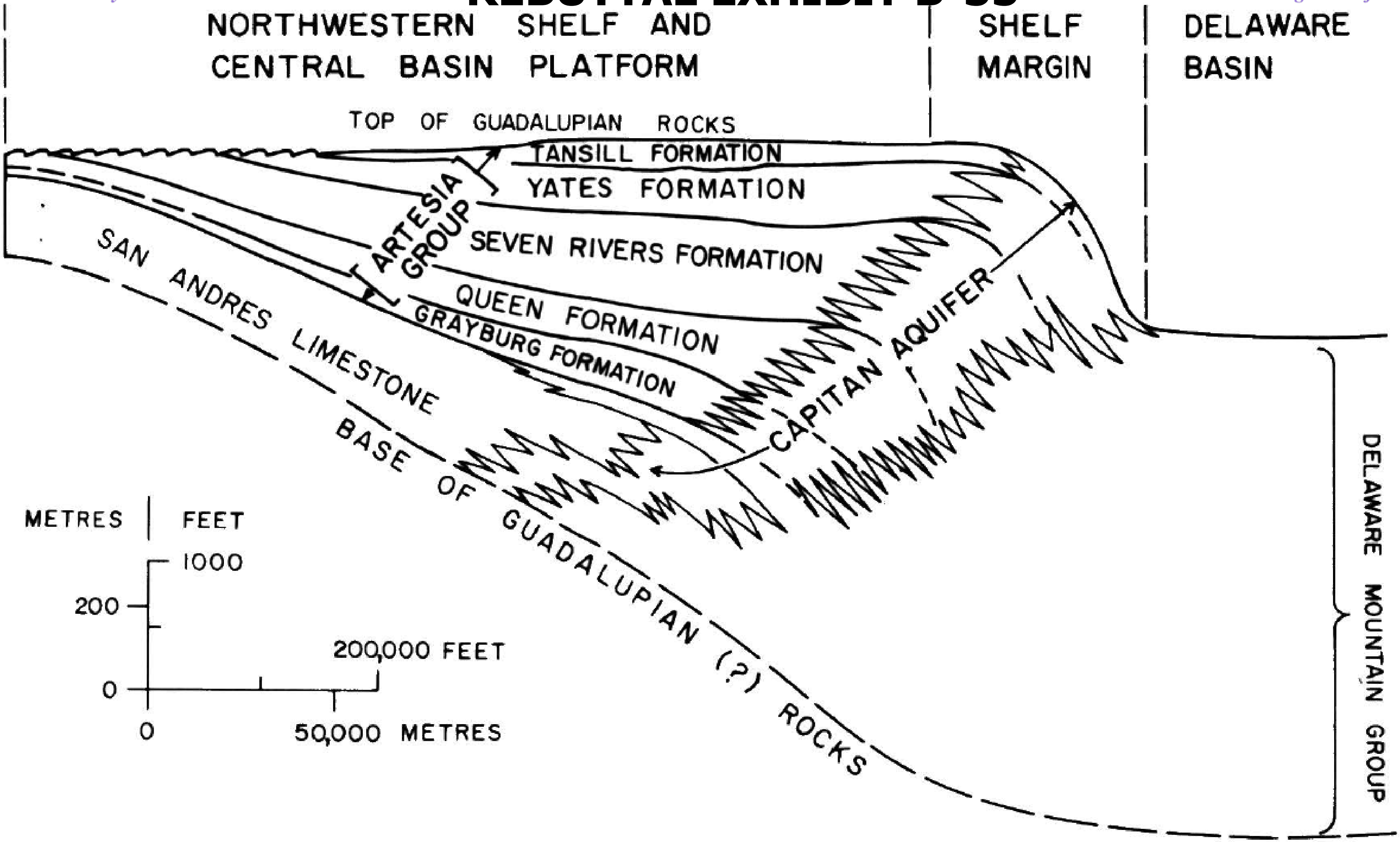
Location of report area and tectonic elements in the Permian basin of west Texas and southeast New Mexico (modified after fig. 7, Oriel, Meyers, and Crosby, 1967, West Texas Permian basin region, in McKee, E. D., and Oriel, S. S., eds., Paleotectonic investigations of the Permian System in the United States: U.S. Geological Survey Professional Paper 515, p. 17-60).

New Mexico base from U.S. Geological Survey, Branch of Oil and Gas Operations, Roswell 9 South 1 inch = 2 miles (1963). Texas base from Midland Map Co. BM-2 (1969), BM-3 (1966), BM-4 (1961), BM-11 (1956), BM-12 (1956), BM-13 (1961), BM-17 (1955), and BM-18 (1955) 1 inch = 5,000 feet, used with permission of Midland Map Co.

CHLORIDE-ION CONCENTRATION IN GROUND WATER IN PERMIAN GUADALUPIAN ROCKS, SOUTHEAST NEW MEXICO AND WEST TEXAS

by W. L. HISS

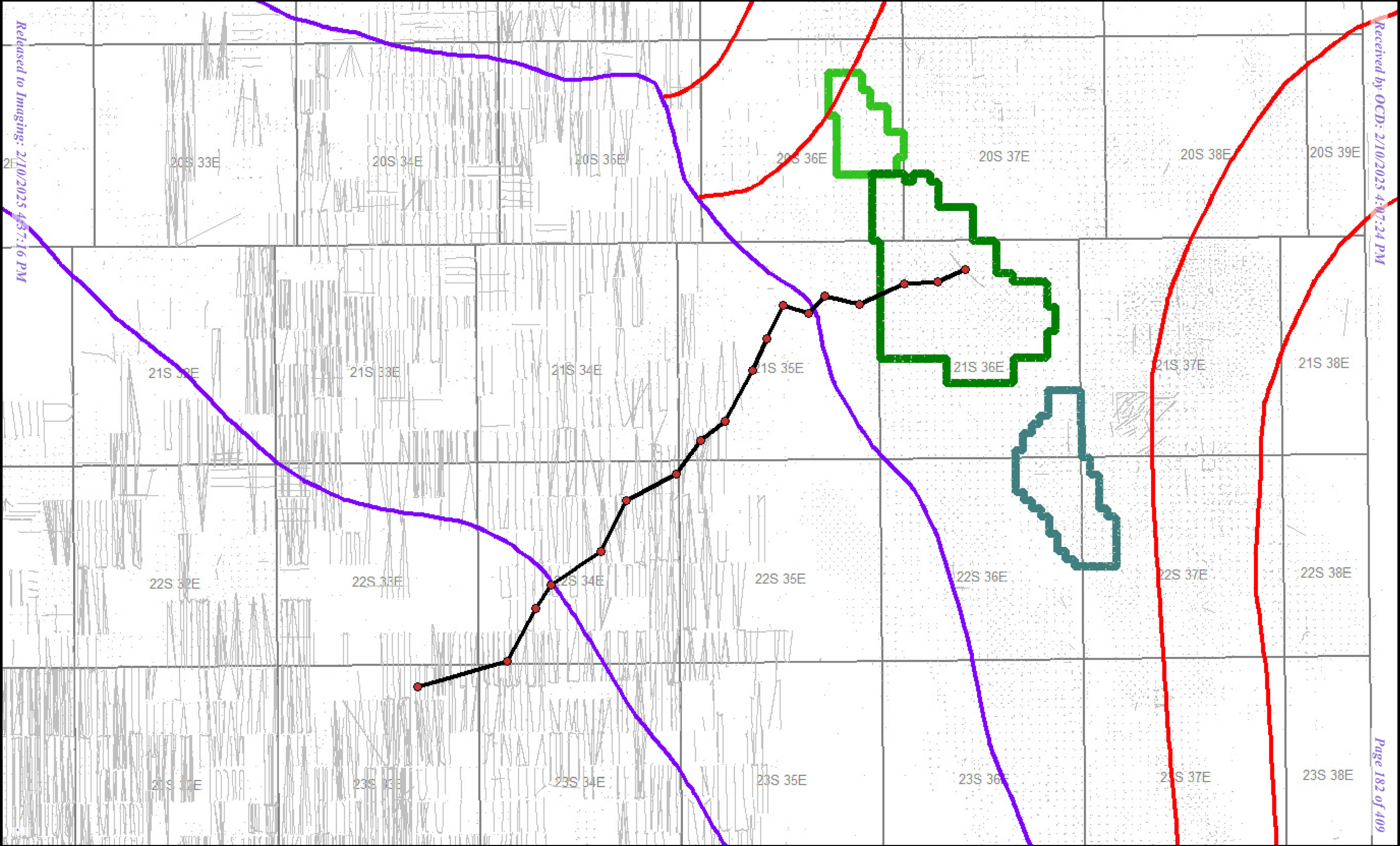
REBUTTAL EXHIBIT B-55



Diagrammatic stratigraphic section showing the position and relationship of rocks of Guadalupian age in southeast New Mexico and west Texas

From Hiss Chloride Ion Concentration Map

REBUTTAL EXHIBIT
B-56


20S 33E
20S 34E
20S 35E
20S 37E
20S 38E
20S 39E
21S 33E
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21S 36E
21S 37E
21S 38E
22S 33E
22S 35E
22S 36E
22S 37E
22S 38E
23S 34E
23S 35E
23S 38E


COG PRODUCTION LLC
STATE HL 001
TWP: 23 S - Range: 33 E - Sec. 2
Datum=3564.00
9449 ft
30025355920000
KAISER FRANCIS
BELL LAKE UNIT 022
TWP: 22 S - Range: 34 E - Sec. 31
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4302 ft
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SANTA FE ENERGY RESCS
GAUCHO UNIT 1
TWP: 22 S - Range: 34 E - Sec. 29
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DEVON ENERGY PRODUCT
GAUCHO 21 FEDERAL 001
TWP: 22 S - Range: 34 E - Sec. 21
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AMERCN QUASAR PETRO
OJO CHISO UNIT 2
TWP: 22 S - Range: 34 E - Sec. 15
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L & B OIL CO INC
STATE 1-11
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GETTY OIL CO
GETTY "11" STATE COM 2
TWP: 22 S - Range: 34 E - Sec. 1
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CIMAREX ENERGY CO. OF COLORADO
NEW MEXICO ST "DA" 2
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COG OPERATING LLC
RAWHIDE 29 STATE 1
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CHEVRON U S A INC
SAN SIMON 21 STATE 2
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P Q OSUDO STATE COM 001
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AMERADA PETR. CORP.
W.A. Merchant 001
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ERNIE L. HEGWER INC
ENDURA 002
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APACHE CORP
STATE W.F.K. 1
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EUNICE MONUMENT SOUTH UNIT 643
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XTO ENERGY INC
EUNICE MONUMENT SOUTH UNIT 457 457
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CONOCOPHILLIPS COMPA
MEYER B 4 019
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500
0
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-1500
-2000
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Salado
Castile
Lamar
Bell Canyon
Manzanita
Cherry Canyon
CC MKR 1
CC MKR 2
Brushy Canyon
Capitan Reef
Goat Seep Reef
Tansill
Yates
Seven Rivers
Queen
Cherry Canyon Tongue
Cherry Canyon Tongue
Yeso
Victorio Peak
Bone Spring
Grayburg
San Andres
Glorieta
Paddock
Tubb
Drinkard
Abo
TD=13430.00
TD=15100.00
TD=13450.00
TD=13575.00
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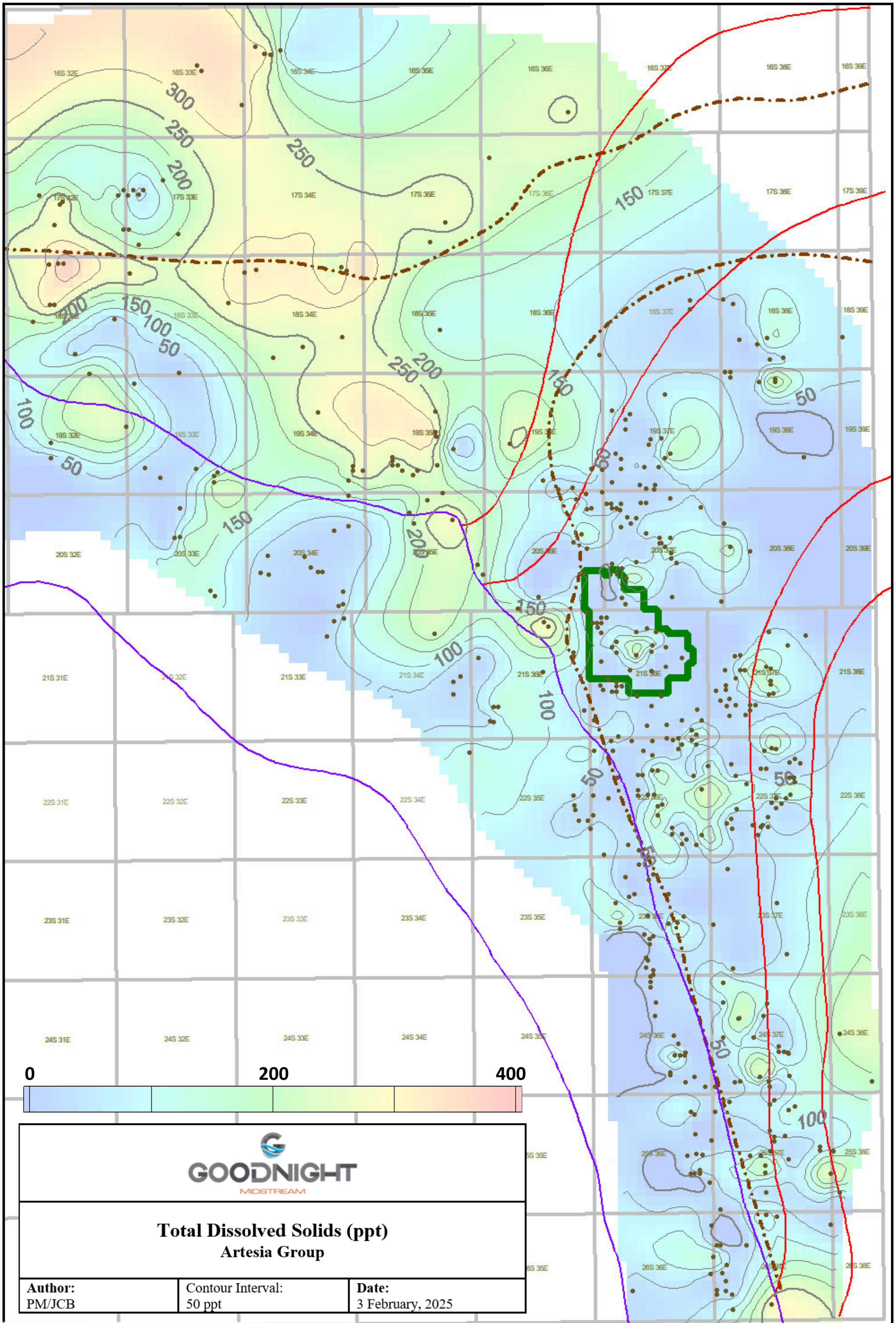
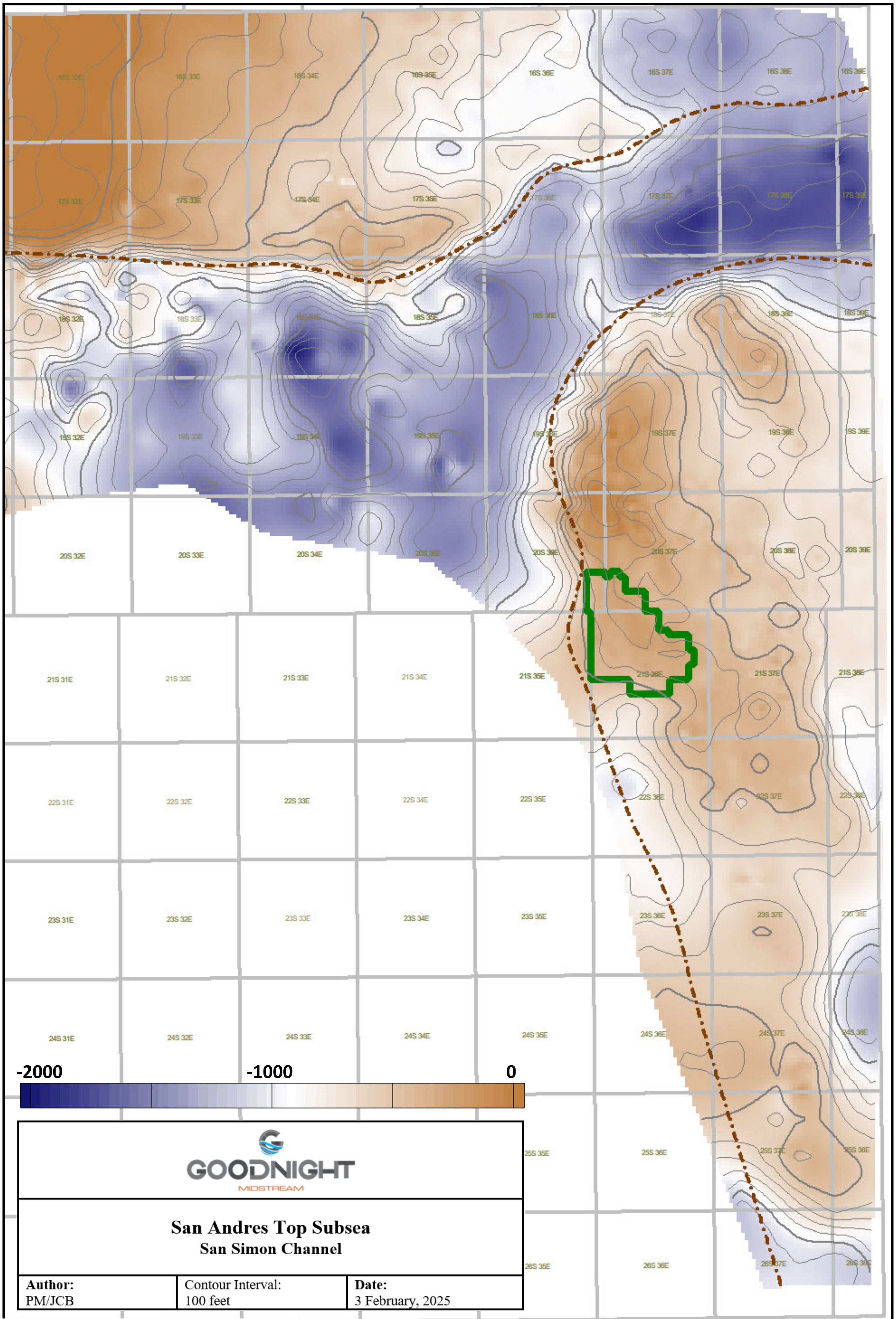
REBUTTAL EXHIBIT B-57

Artesia Group Total Dissolved Solids



San Simon Channel

REBUTTAL EXHIBIT B-58



REBUTTAL EXHIBIT B-59

Map from OCD Exhibit 4 Page 43

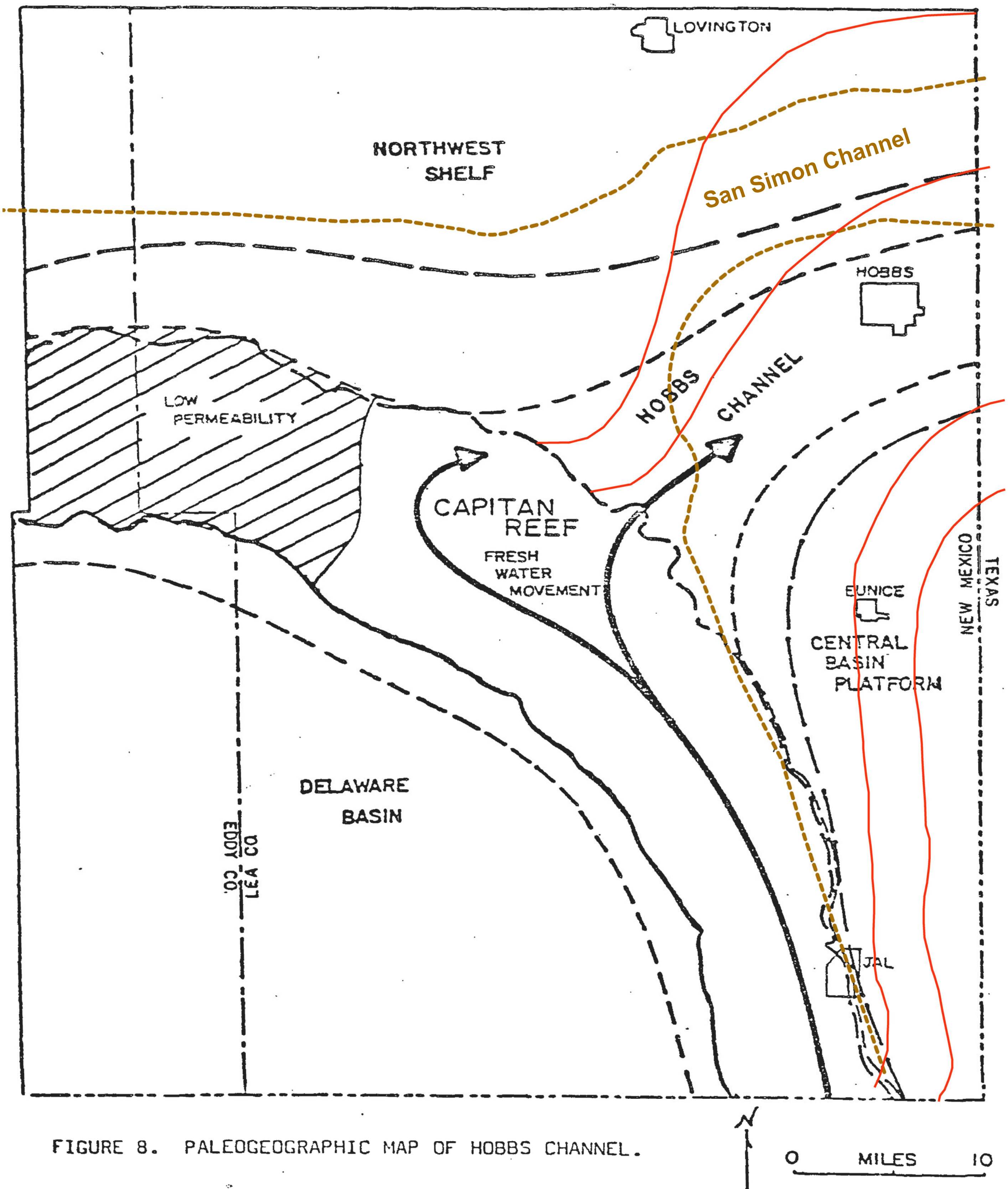


FIGURE 8. PALEOGEOGRAPHIC MAP OF HOBBS CHANNEL.

Source: Modified after W. Hiss, 1975 by M. Holland.

SADR and DMG Total Dissolved Solids

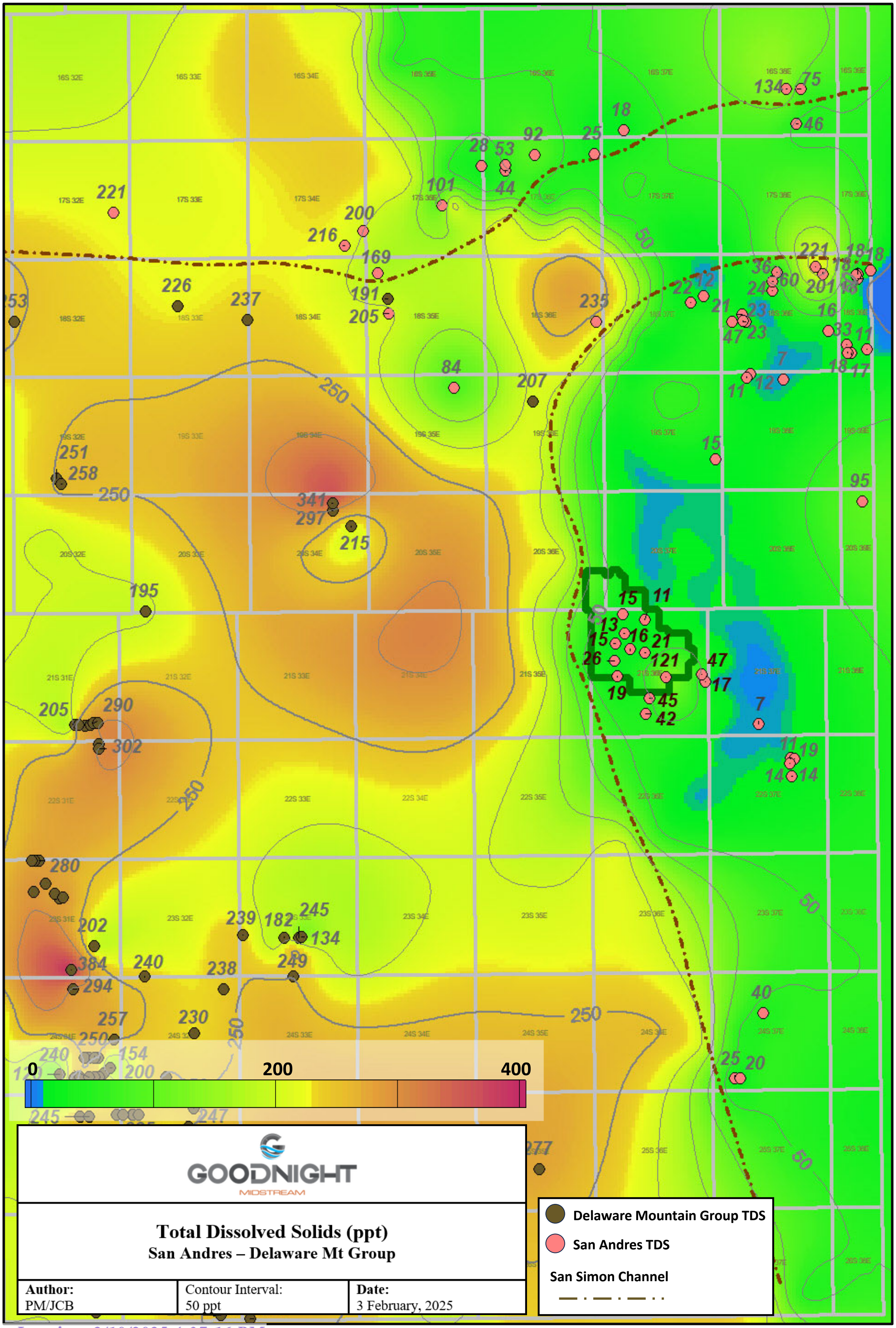
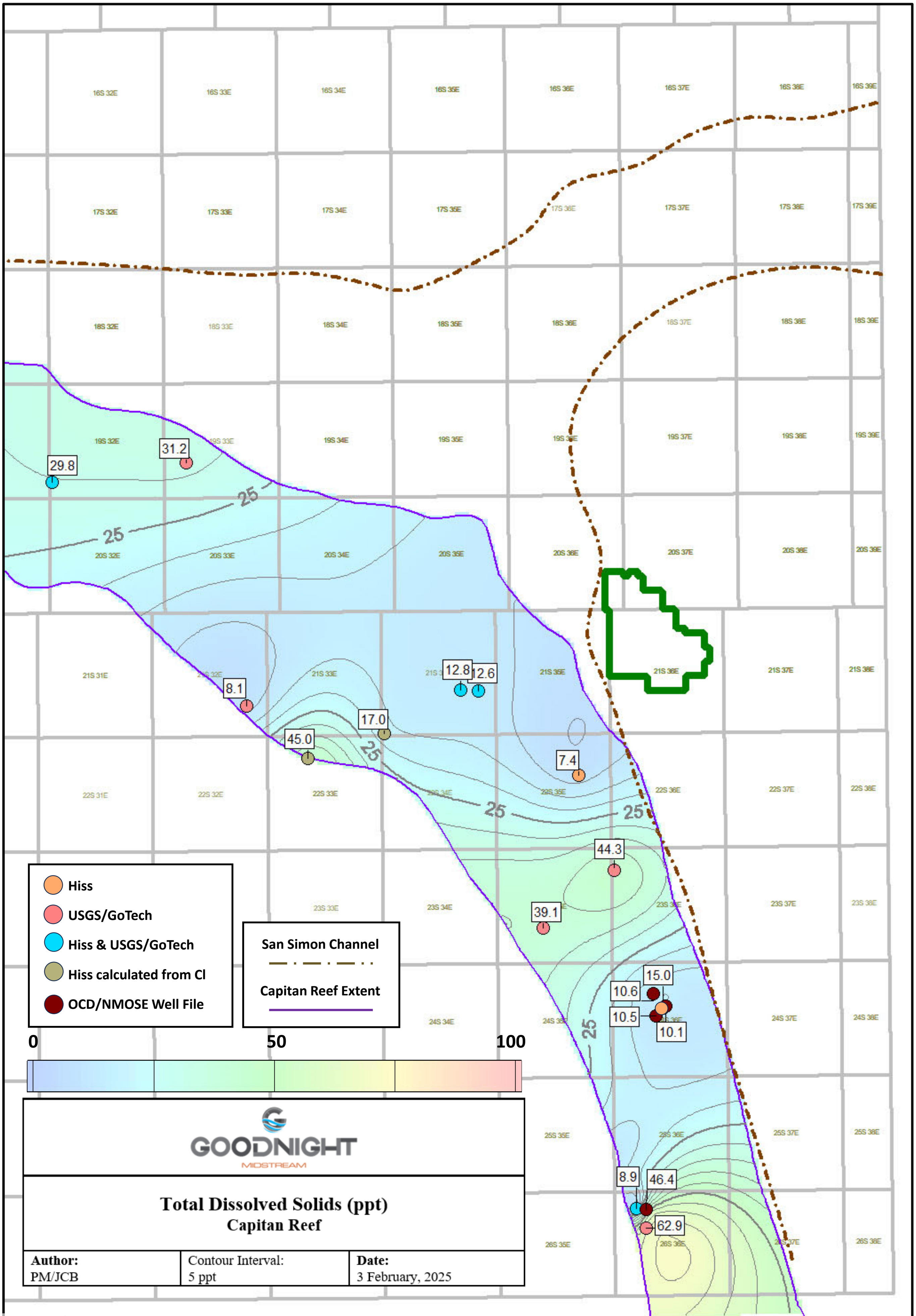


EXHIBIT B-61

Capitan Reef Total Dissolved Solids



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

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO

CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO.

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24020, 24025

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.

DIVISION CASE NO. 22626
ORDER NO. R-22869-A
COMMISSION CASE NO. 24123

SELF-AFFIRMED REBUTTAL STATEMENT OF THOMAS E. TOMASTIK

1. My name is Thomas E. Tomastik. I work for ALL Consulting, LLC as the Chief Geologist and Regulatory Specialist. In this role, I manage injection well projects throughout the United States, including New Mexico. I am familiar with the applications in the above-referenced cases.

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. C
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

2. I have been asked to prepare this rebuttal statement in response to statements and depositional transcripts by Empire's witnesses and the New Mexico Oil Conservation Division (NMOCD).

3. I have previously testified before the New Mexico Oil Conservation Division ("Division") as an expert witness in petroleum engineering, hydrogeology, and petroleum geology. My credentials as an expert have been accepted by the Division and made a matter of record. I have previously attached my current curriculum vitae as **Goodnight Exhibit C-1 to my Self-Affirmed Statement**. It outlines my education, training, and experience, as well as a list of my publications and presentations.

Rebuttal Summary

4. I have been asked to review the direct testimony, exhibits, and additional data and new information provided by the parties relating to the applications filed by Goodnight Midstream and Empire in these cases. I have been asked to review the additional new data and information relating to the applications filed by Goodnight Midstream and Empire in these cases. I have conducted further study on the additional information and this, along with my experience, forms the basis of my rebuttal opinions expressed herein. I have made a good faith effort to anticipate Empire and NMOCD testimony based on the information I have reviewed, but I reserve the right to revise or expand my testimony or to respond to new assertions, allegations, or testimony of Empire or NMOCD and their witnesses.

5. Specifically, I have been asked to evaluate and assess the new information from Empire and NMOCD and provide additional rebuttal testimony on: (1) William West's deposition and transcript; (2) Overview of primary and secondary (waterflood operations) of the EMSU; (3) Empire's claims regarding corrosion and scaling issues associated with the EMSU and Empire's allegations of chloride corrosion caused by Goodnight's San Andres SWD injection operations;

(4) Analysis of the testimony by Empire regarding their chemical/treating protocols and the general water chemistry of both the Grayburg and San Andres formations; (5) Assessment of Empire's agreed compliance order for inactive well status from January 2024 to July 2024; (6) Further discussion of the geologic seal and barrier between the Grayburg Formation and the top of the Goodnight San Andes injection zones in the San Andres; (7) Review and assessment of NMOCD self-affirmed statement regarding the Capitan Reef, Goat Seep Formation, and potential need for aquifer exemptions for Class II injection into the San Andres Formation.

6. I have thoroughly researched all the available documents, records, and publications including but not limited to:

- **William West's two transcripts;**
- **Dr. Robert Lindsay's transcript;**
- **W.L. Hiss (1975) PhD dissertation;**
- **NMOCD's self-affirmed statement and exhibits;**
- **Lewis Land New Mexico Open-File Report 583;**
- **Male and others (2024) presentation;**
- **Dr. Robert Lindsay's self-affirmed statement; and**
- **Further review of existing publications and other documents listed in my reference section.**

7. The following is a summary of rebuttal topics that are addressed in my rebuttal statements below.

- Overview of Production and Waterflood Operations;
- Chloride Corrosion Issues;
- Scaling and General Water Chemistry;
- Empire's Claimed ROZ;

- Empire's Agreed Compliance Order;
- San Andres Upward Migration Barrier and Claimed Fractures;
- Empire EMSU CO_2 Plans;
- Capitan Reef and Goat Seep Aquifer; and
- Underground Injection Control and USDWs.

OVERVIEW OF PRODUCTION AND WATERFLOOD OPERATIONS IN THE EMSU

8. A continued overview of the primary production and waterflood operations at the EMSU and publications demonstrate the following points which support my rebuttal statement:

- Water was first produced in the EMSU in the 1930s with water encroachment from the west, southwest, and southeast edges of the field, but the water drive appears to be most active in the southwestern portion of the field.
- By late 1941, water encroachment was uniform on the west and southern parts of the field, while the east edge, because of lower permeability, was less evenly encroached on. The central part of the pool had the largest percentage of oil wells still free from water.
- Water encroachment in the EMSU is further demonstrated by **Exhibit C-12** (Page 48 of the transcript for Case No. 12,320 on March 2, 2000, has testimony from Tracey Love of Chevron) states *"They show in some areas that we're producing more water than we've put in. And that comes from the edge water to the west, there's an edge water encroachment to the west, and the wells on the west side exhibit more water influx than we put in."*
- The Chevron 1991 SPE Paper documented that the **San Andres Formation was under low-pressure** during the drilling of the water supply wells and large horsepower submersible pumps were used to pump the make-up water for waterflooding operations.
- **Exhibit C-13** - William West's direct testimony claims there was oil produced from the San Andres Formation from three wells, the EMSU #660, EMSU #658, and EMSU #577 [William West transcript, December 3, 2024, Page 12 (Pages 42-45)].
- Empire's only documentation of alleged show of oil from the San Andres Formation is from a well test in the EMSU #660, which was drilled and completed by XTO in late 2005 that was never filed into the NMOCD's public well file records. The well test produced de minimis oil from the San Andres along with large volumes of water and the well was then plugged back to the Grayburg Formation. In the review of all of the NMOCD documents for this well on their website, there is no testing document or Sundry Notice indicating any oil

production from the San Andres. The Sundry Notice indicates after the San Andres was perforated it was swabbed on December 14, 2005, and a submersible pump was run on December 15, 2005. There is no Form C-104 for the San Andres testing and on March 2, 2006, a cast iron bridge plug (CIBP) was set at 4,000 feet to isolate the San Andres perforations. On March 10, 2006, a 24-hour production test was conducted on the perforations in the Grayburg Formation above the CIBP.

There are no C-104s from the commencement of waterflooding to present indicating any oil production from any of the EMSU water supply wells.

- On the EMSU #457 water supply well, after being perforated, the well was swabbed and recovered 8,636 barrels of water in 19 hours and no oil production reported.
- Completion of the EMSU #458 water supply well had a production test of 925 barrels of water and no oil production.
- On the EMSU #461 water supply well, after perforating it tested 750 barrels of water and no oil.
- The other three water supply wells (EMSU #462, EMSU #459, and EMSU #460) also reported no oil production.

- William West testified he heard from someone, but could not remember who, that the EMSU water supply wells tested oil in the San Andres, but no evidence has been presented to confirm this. In response to a request for documents, Empire confirmed that, after a diligent and thorough search, it has been unable to locate any documents showing any oil or skim oil was produced from any of the EMSU water supply wells **(Exhibit C-14**).
- **Exhibit C-15** is from Page 3 from Exhibit No. B-14 – Case No. 23614-23617, November 2, 2023, and states *"For the proposed unit, saltwater from the **non-productive San Andres Formation**, supplemented by the reinjection of produced water, was recommended for pressurized injection into the oil producing portions of the Grayburg and Lower Penrose formations."*
- As can be seen, there are multiple documents from Gulf/Chevron regarding the ESMU waterflood that clearly defines the San Andres Formation as non-productive and only to be used for make-up water for the waterflood and disposal of produced water—both existing prior to formation of the EMSU and in support of EMSU operations.

CHLORIDE CORROSION ISSUES

9. In William West's deposition, he states that he does not rely on any scientific papers or studies for his assertion that chlorides cause corrosion in oil and gas wells because it is just a known fact that chlorides cause corrosion. As addressed in my self-affirmed statement, chloride corrosion is not a primary corrosive agent in the oil and gas industry. Hydrogen sulfide

(H_2S), oxygen, microbial-induced corrosion, and carbon dioxide (CO_2) are the prevalent corrosive agents in the oil and gas industry.

10. It is well documented in the EMSU that:

- Corrosion occurred well before commencement of waterflooding and continued after waterflooding operations commenced with the intermixing of make-up water from the San Andres (Chevron, 1991; 1996);
- Historical corrosion and scaling occurring in the Grayburg wells are not associated with injection operations from the Goodnight SWDs;
- Between 1989 and 1992—more than 25 years before Goodnight started its injection operations into the San Andres—Chevron (1996) sampled and analyzed produced waters from 153 EMSU producing wells and found the following:
    - Chloride concentrations from the 153 EMSU producing wells ranged from a low of 1,996 mg/L to a high of 55,453 mg/L.
    - Eighty-six of the wells were sampled and analyzed multiple times annually between 1989 to 1992 and chloride concentrations either increased or decreased over annual sampling periods, indicating that at different times there was either an influx of higher salinity or lower salinity waters into the Grayburg formation during the Chevron sampling period.
    - **Table 1** below shows examples of chloride levels decreasing and increasing over time in both the Grayburg and San Andres formations.

EMSU Well No.	Date Sampled	Chloride Concentration (mg/L)	Date Sampled	Chloride Concentration (mg/L)	Increase or Decrease in Chloride Concentration
214	11/01/1990	22,836	11/01/1991	6,762	Decrease
228	10/01/1989	2,972	10/01/1991	21,522	Increase
256	10/01/1989	3,789	10/01/1991	55,453	Increase
119	11/01/1990	32,300	11/01/1991	14,600	Decrease
457 WSW	10/01/1989	2,000	10/22/1992	8,280	Increase

- This documentation by Chevron (1996) clearly demonstrates that there have been substantial fluctuations (increases and decreases) in chloride concentrations for approximately 33 years prior to commencement of Goodnight injection operations and further demonstrates chlorides played a minor if any role in corrosion issues.
- Empire presented a total of 31 sampling and analysis events from 21 EMSU Grayburg producing wells between November of 2023 and November of 2024. The sampling

results show a range of TDS from a low of 17,971 mg/L to a high of 28,203 mg/L and a range of sulfates from a low of 12 mg/L to a high of 2,545 mg/L.

- **Exhibit C-16** shows the location of these Grayburg wells in relation to all of the San Andres SWDs in this area.
- There is no discussion from Empire as to why certain production wells were selected for sampling and analysis. Additionally, there is no technical interpretation of the analytical results nor is there any associated chemical treatment recommendation from Empire's chemical treating consultant or if treatment is even recommended for these wells. Additionally, the question arises as to why no fluids from Grayburg injection wells have been sampled and analyzed? Are the Grayburg injection fluids chemically treated at the surface facilities prior to injection?
- In William West's transcript, Mr. West testified that Empire's chemical treating company made recommendations for chemical treatment, but Empire made its own decisions on chemical treatment and Mr. West admitted that cost is a consideration. Goodnight requested copies of all chemical treatment recommendations made to Empire by its chemical treatment consultant for the EMSU, but none were provided.
- Mr. West testified that he did not know if Empire was following the chemical treatment programs that had been previously established by Chevron or XTO and was not aware of any historical record or protocol guidance or program from EMSU's prior operators.
- Additionally, Mr. West confirmed that Empire does not appear to have a comprehensive chemical treatment program other than an assortment of acid jobs.

- Empire has presented no technical evidence of chloride corrosion, or any other corrosion associated with Goodnight's injection operations, let alone any anecdotal evidence. In his deposition, Mr. West was unable to identify any specific wells or instances where he could identify impacts to Empire's wells from Goodnight's injection. See **Exhibit C-17**, Tr. 140:19-141:3. The only evidence he was able to cite in support of impacts is an alleged increase in salinity. See **Exhibit C-18**, Tr. 142:9-143:3. But as documented in the table above, the Grayburg Formation has historically experienced a wide swing in documented water quality concentrations that exceed/are in line with the more recent sampling events conducted by Empire.

SCALING AND GENERAL WATER CHEMISTRY

11. Empire fails to acknowledge that scaling and corrosion in the EMSU that existed prior to Goodnight's injection operations is well documented, and that scaling is the predominant corrosion issue associated with the EMSU even before commencement of waterflooding operations. Scaling and corrosion were further exacerbated by the use and incompatibility of San Andres make-up water for waterflooding operations and the age of the majority of the Grayburg

wells, which led to extensive workovers and deepening by Chevron during the initial preparation for the commencement of waterflooding in the early 1980s.

- Empire has provided zero written documented evidence or photographs of corrosion or scaling of surface equipment, pipelines, downhole tubulars, pumps, etc. No specific wells were identified, no scaling or corrosion reports, or any examples of impairment or impacts were provided.
- Empire has not provided any of the chemistry data from either Chevron or XTO's operations at the EMSU, which has been repeatedly requested, that might support or contradict Empire's arguments.
- An analysis of the sulfate chemistry data provided in the 1996 Chevron paper, 2000 Go Tech data, and Empire's late 2023 to November of 2024 chemistry data clearly shows the same chemistry fluctuations with sulfate concentrations on some wells increasing over time and some wells decreasing over time, just like the historic chloride chemistry data shows. These documented chemistry variations are not surprising, align with historic water chemistry fluctuations, and do not provide support for Empire's arguments.
- **Table 2** below shows examples of sulfate decreasing and increasing over time.

EMSU Well No.	Date Sampled	Sulfate Concentration (mg/L)	Date Sampled	Sulfate Concentration (mg/L)	Increase or Decrease in Sulfate Concentration
298	11/01/1991	763	10/01/2024	612	Decrease
441	10/01/1991	1,503	10/01/2024	125	Decrease
278	11/01/1990	204	11/08/2024	2,545	Increase
319	10/01/1989	209	10/01/2024	954	Increase
440	11/01/1990	2,500	10/01/2024	345	Decrease

12. As can be seen with the analysis of the documented chemistry data available for the EMSU, there is no geochemical fingerprinting that can be utilized to claim that the injection fluids at the Goodnight SWDs have allegedly altered the chemistry in the San Andres or Grayburg formations which is causing corrosion and scaling issues in the existing EMSU waterflooding operations. In short, there is simply no evidence to support the conclusion that Goodnight's

disposal water is affecting the EMSU water chemistry in the Grayburg or impacting any of Empire's EMSU wells.

EMPIRE'S CLAIMED ROZ

13. Additionally, the injection of the **fluids from the Goodnight SWDs is not impacting Empire's alleged potential CO_2 tertiary operations in the San Andres ROZ.** In all realty, Goodnight's injection operations are actually refilling the pore space from the huge volumes of water withdrawn from the San Andres for waterflooding operations, which overtime, would decrease the amount of CO_2 needed to repressurize the alleged San Andres ROZ if there is an effort by Empire to attempt a CO_2 tertiary recovery operation.

14. Even if the claimed San Andres ROZ exists, why has no oil been produced or reported since commencement of the waterflooding operations with the withdrawal of approximately 340 million barrels of water from the San Andres for make-up water for injection into the Grayburg for waterflooding operation?

EMPIRE'S AGREED COMPLIANCE ORDER

15. On November 7, 2023, Empire agreed to a compliance order with NMOCD for inactive wells, including wells in the EMSU. There was a total of 48 wells on the compliance order for EMSU and between November of 2023 and June of 2024, all 48 EMSU wells were returned to compliance. However, a number of wells were simply placed under temporary abandoned status. Out of the 48 EMSU wells returned to compliance, only two wells have been plugged and abandoned. The rest of the 48 wells returned to compliance were either temporarily abandoned or returned to production.

16. The only two EMSU wells that were plugged and abandoned by Empire from the agreed Compliance Order were plugged in 2024. These two Empire wells were at least 3.8 to 4

miles north of the closest Goodnight SWD (Sosa SA SWD) in the San Andres Formation. There have been no wells plugged and abandoned due to alleged impacts from the Goodnight SWDs.

SAN ANDRES UPWARD MIGRATION BARRIER AND CLAIMED FRACTURES

17. Based on the deposition testimony of Dr. Robert Lindsay in **Exhibit C-19**, the question was asked *"In your opinion is there a barrier to fluid flow at the top where you picked the San Andres, between the San Andres and the Grayburg?"* Dr. Lindsay responded *"There should be one, because normally at that, at the top of the San Andres, that's called a composite sequence boundary, and they tend to cement up a little bit. But what I've been able to see on well logs, it's not much of a barrier."* This statement is again supported by Dr. Lindsay's PhD from 2014 regarding the reservoir seal and that the pressure differential between the formations confirms the barrier.

18. However, despite his clear conclusion on the effectiveness of the barrier between the Grayburg and San Andres in his dissertation, Dr. Lindsay appears to now be taking a different position in these cases even though there is no new or additional information since his dissertation in 2014. He points to fractures that he contends extend into the San Andres and allow for communication.

19. The Chevron in-house fracture study referred to in Dr. Lindsay's self-affirmed statement is limited to fracture analysis from one well, EMSU #679. The fracture analysis referred to in Dr. Lindsay's self-affirmed statement is limited to the Grayburg and does not extend into the San Andres.

20. Dr. Lindsay's fracture analysis fails to discuss any drilling induced fractures, which are common in cores.

21. On Dr. Lindsay's Exhibit B-18 core photograph, there are two non-induced vertical fractures that dead end into a horizontal stylolite, which serves as a barrier to continued fracture extension (**Exhibit C-20**). This is an example of horizontal geologic barriers that exist that prevent continuation of natural vertical fracture extension in carbonate rocks. It also does not extend to Goodnight's pick for the top of the San Andres at -672 feet subsea depicted in Goodnight Exhibit B-32, where it has identified a geologic seal.

22. Dr. Lindsay's Exhibit B-23 clearly shows a low porosity confining zone directly below his Grayburg/San Andres Formation contact (**Exhibit C-21).** But as noted above, Goodnight's pick for the top of the San Andres and the confining layer for its disposal zone is deeper and clearly identified with low vertical permeability from the core analysis. See Goodnight Exhibit B-27.

23. Based on my extensive field experience with naturally fractured rocks and my publications regarding them, the fractures identified in Dr. Lindsay's self-affirmed statement and core photographs are discontinuous and some are sealed with secondary mineralization. My self-affirmed statement regarding naturally fractured rocks clearly shows how horizontal bedding planes tend to act as barriers to vertical fluid flow.

24. Additionally, as I stated in my direct written testimony and in my deposition, there are no continuous fractures extending downward from the Grayburg 285 to 463 feet into the San Andres injection zones utilized by the Goodnight SWDs.

EMPIRE EMSU CO_2 PLANS

25. William West testified extensively in his deposition regarding the San Andres ROZ and estimated oil recovery by CO_2 tertiary recovery. In **Exhibit C-22** [William West Transcript December 4, 2024, Page 38 (Pages 42-45)], Mr. West's response is as follows:

- **Question** – *"Okay. So, in the economic analysis that we just received, you told me that you use an 18 percent recovery factor, correct?"*
  - Mr. West responded, *"That is what it has on there."*
- **Question** – *"Okay, and in order to get – and that economic model gives us a recovery of approximately 140 million barrels of oil, correct?"*
  - Mr. West responded, *"That is correct."*
- **Question** – *"Okay. But in your testimony, you say that it's estimated that by flooding the ROZ, you can get 270 million barrels, correct?"*
  - Mr. West responded, *"That is an estimation."*

26. The question becomes if Chevron and XTO/ExxonMobil knew of the existence of the San Andres ROZ and the potential for the recovery of 140 to 270 million barrels of oil by CO_2 tertiary injection, why would a major oil company sell the EMSU? It is well documented that XTO attempted to produce the San Andres from three EMSU wells (EMSU #660, EMSU #658, and EMSU #577). They drilled, swabbed, and tested all three wells in 2006 with no commercial production of oil and the wells were plugged back to the Grayburg Formation.

27. Empire does not seem to understand that in order to even consider an attempt to inject CO_2 into the San Andres ROZ, you must refill the pore spaces that had been dewatered by almost 40 years of withdrawal of approximately 340 million barrels of water from the San Andres.

CAPITAN REEF AND THE GOAT SEEP AQUIFER

28. NMOCD filed its Exhibit List and Witness Testimony disclosure on August 26, 2024, with the concern that there may be a connection to the "Hobbs Channel" with the San Andres

injection wells, which in turn could potentially communicate with the Capitan Reef, which is an underground source of drinking water (USDW).

29. I have reviewed all of the publications submitted as exhibits by NMOCD, the research and work undertaken by Goodnight Midstream on the "Hobbs Channel", the Capitan Reef, and have reviewed more current geological presentations and publications regarding the Capitan Reef and facies changes in the Goat Seep aquifer.

30. Based on my review of all of these publications and presentations, there is no stratigraphic correlation or facies connection between the San Andres Formation and the Capitan Reef or the Goat Seep aquifer. A recent presentation by Male and others (2024) shows a geologic cross section that clearly shows the Goat Seep aquifer grading into the Queen and Grayburg formations and is not associated with the San Andres Formation (**Exhibit C-23**).

31. Additionally, Land (2016) makes the following statement regarding the Capitan Reef east of the Pecos River (**Exhibit C-24**).

- *"Because of the highly saline nature of groundwater in the Capitan Reef east of the Pecos River, very few water supply wells were completed in that portion of the aquifer. Until recently, the only water quality information available for the reef east of the Pecos River was from a network of monitoring wells installed by the U.S. Geological Survey in the mid-20th century (Hiss, 1975a; Hiss, 1975b). These records confirm the highly mineralized character of groundwater in the eastern segment of the Capitan Reef, resulting in a mean TDS concentration for the entire aquifer of > 54,000 mg/L."*
- Also, back in 2021, during Goodnight's hearing on the Andre Dawson and Ernie Banks SWD applications, NMOCD had requested ALL Consulting (ALL) to determine the proximity of the Capitan Reef to the proposed San Andres SWDs. ALL supplied this information to NMOCD, which showed these proposed SWDs were 2.8 to 3.2 miles from the reef (**Exhibit C-25**).
- In regard to the "Hobbs Channel", **there is no published reference to the "Hobbs Channel" as a geological feature** and supposedly Hiss (1975) based this groundwater flow channel not on geology but based it on chloride sampling results and his contouring of the chloride data. **Exhibit C-26** is a snip of the Hiss (1975) map which supposedly shows the "Hobbs Channel" off the San Simon Channel, which is a known geological feature. However, a scientific examination

of the chloride data that was contoured by Hiss (1975) on this map clearly violated the widely accepted hand-contouring standards at that time and currently in use. This brings into question the scientific acceptance of the "Hobbs Channel" as a groundwater flow feature.

UNDERGROUND INJECTION CONTROL AND USDWS

32. On September 15, 1981, NMOCD submitted their Class II Underground Injection Control Class II Demonstration to U.S. EPA for primacy approval. On page 53 of this document (**Exhibit C-27**), NMOCD requested that the Tansil, Yates, Seven Rivers, Queen, Grayburg, and San Andres formations within Lea County, New Mexico be classified as exempted aquifers. Additional responses to U.S. EPA Region VI on October 24, 2016, and then again on May 28, 2020, reiterated NMOCD statements regarding the classification of the Artesia Group formations and the San Andres Formation in Lea County to be classified as exempted aquifers. The main concern in both 2016 and 2020 was injection into the Capitan Reef or directly above it, which is considered a USDW west of the Pecos River, but likely not a USDW east of the Pecos River. There was no referenced concern about injection into the San Andres.

33. I was employed by the Ohio Department of Natural Resources, Division of Oil and Gas Resources Management in the UIC Section from December of 1988 till mid-August of 2014. I was the senior geologist in Ohio's Class II UIC program for those 25-1/2 years and also served as a state representative to the U.S. EPA UIC National Technical Workgroup for over six years. I am very familiar with many of the U.S. EPA UIC staff in all of the U.S. EPA regional offices and the headquarters office in Washington D.C.

34. On March 28, 2024, I contacted U.S. EPA Region VI, as I know Mr. Ken Johnson, EPA's UIC Manager, very well. I was interested in seeing the list of exempt aquifers in New

Mexico. I received a response back from U.S. EPA Region VI with the list of the exempted aquifers and none were listed for Lea County, New Mexico.

35. The question becomes why U.S. EPA Region VI has not honored NMOCD's multiple requests since the initial primacy application in 1981 to classify the Artesia Group and the San Andres Formation as exempted aquifers for Lea County, New Mexico? NMOCD has provided detailed technical information multiple times to support this request. There are no documents available online from U.S. EPA Region VI denying the exempted aquifer request nor is there an explanation from U.S. EPA Region VI as to why these formations could not be exempted aquifers. Under Federal regulation 146.04 and 146.03 under 40 CFR 122.35, the criterion for an exempted aquifer clearly shows that the Artesia Group and the San Andres Formation east of the Pecos River meets the criteria for aquifer exemption.

36. I have advised and trained Class II regulators from across the U.S. on injection wells at national conferences and have published or presented numerous times on Class II injection wells. Additionally, as Chief Geologist with ALL Consulting, I have drilled, completed, tested, plugged, and performed workovers on over ten Class II SWDs in the last ten years.

37. Based on my review and experience with U.S. EPA as both a regulator and now as a consultant, Goodnight Midstream's current Class II SWD injection operations and their proposed new SWDs are protective of the USDWs in the Capitan Reef and Goat Seep as these wells are not in communication with the Capitan Reef or Goat Seep. Additionally, the sampling performed, and analysis conducted by Goodnight on the San Andres for each SWD prior to commencement of injection operations as required by Class II permit condition orders, **clearly demonstrated that the San Andres is not a USDW at the location of the Goodnight SWDs and is not in communication with one.**

CONCLUSIONS

38. Based on my technical assessment and analysis the following are my conclusions:

- It is well documented in historic publications and in Chevron published papers that corrosion and scaling occurred well before the commencement of waterflooding in the EMSU. Chevron experienced many issues with well workovers prior to commencement of waterflooding due to the age of the wells, corrosion and scaling, and junk and fish in the wells. Additionally, the use of the San Andres water for make-up water for waterflooding—despite known incompatibility issues—in all likelihood increased the scaling and corrosion problems that required Chevron's active chemical treatment program.
- There is no evidence of oil production from the San Andres Formation other than alleged shows in swabbing tests and no documentation, reporting, or filing of any C-104s from any of the San Andres water supply wells since commencement of withdrawing upwards of 340 million barrels of make-up water from the San Andres for water flooding.
- Mr. West claims that three EMSU wells drilled into the San Andres produced oil, but no oil was produced from any of the water supply wells and Empire has confirmed there is no documentation of oil production. How is it possible that no oil was produced after such a substantial depressurization in the San Andres if the alleged ROZ really exists?
- Water chemistry from both the Grayburg and San Andres formations are clearly variable and inconsistent, which leads to the fact that no one constituent or concentration of a constituent can be used for geochemical fingerprinting.
- Any fracturing identified in cores are discontinuous and highly variable which is typical for naturally fractured carbonate rocks. There is no evidence presented showing vertical fracture extension from the Grayburg into the existing injection zones which are from 285 to 463 feet below the top of Empire's pick or the San Andres Formation in the Goodnight SWDs.
- There is no geologic evidence showing that the Goat Seep aquifer grades into the San Andres, but it in fact grades into the Queen and Grayburg formations. Additionally, the San Andres is not connected or in hydraulic communication with the Capitan Reef. Most published literature shows the Capitan Reef as being saline east of the Pecos River.
- Hiss's 1975 chloride contour map, which is used to allegedly delineate the ground water flow into the "Hobbs Channel" completely violates the standardized methodology used for contouring of data and is not reliable to delineate the alleged ground water flow into the "Hobbs Channel."
- Sampling and TDS analysis of all of the Goodnight San Andres SWDs clearly shows the San Andres is not a USDW.

- NMOCD has since 1981 attempted to have all of the Artesia Group and the San Andres Formation in Lea County classified as exempt aquifers. There is no documentation found to determine why U.S. EPA Region VI has not honored this request.

39. I affirm under penalty of perjury under the laws of the State of New Mexico that the foregoing statements are true and correct. I understand that this self-affirmed statement will be used as written testimony in this case. This statement is made on the date next to my signature below.

Thomas E. Tomastik
____
Thomas E. Tomastik

February 7, 2025
Date

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EXHIBITS

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A. Yes.
Q. Okay, and what do those show you?
A. They show in some areas that we're producing more water than we've put in. And that comes from the edge water to the west, there's an edge water encroachment to the west, and the wells on the west side exhibit more water influx than we put in.
Q. Okay, what about the rest of the waterflood area?
A. No, we produce most everything we inject.
Q. Okay, and that's always --
A. Except for on the west side where you have the edge water encroachment.
Q. Okay, and that's always been the case?
A. Yes, sir.
Q. All right.
A. Except for the start of the flood before the water broke through in some of those high-permeability streaks. We have a real bad problem with cycling water through those high-permeability streaks. They're like pipelines, and until those broke through we were -- you know, water production was lower.
But once the injection broke through, you're almost at one with your water in, water out, till you squeeze out of those high-permeability streaks.
Q. Let me go back, if I could. Let me ask you this.

REBUTTAL EXHIBIT C-13

Mr. West, are you aware of any primary production occurring below this blue dolostone anywhere within the unit below that depth, anywhere -- correlative depth anywhere in that unit?
A. Can you tell me what subsea depth you have there?
Q. You don't have subsea depths on these exhibits, so I cannot give you a subsea depth.
A. I'll have to convert the depths. I can't really read the depths on this, these logs.
Q. Let me ask you this: Are you aware of any primary production within the San An- -- within the EMSU unit from within or below the interval that was completed by the water supply wells?
A. This is the 660; is that correct?
Q. The 460.
A. 460. There's -- there's been four wells in the EMSU that's, you know, tested oil in the San Andres.
Q. Which are those?
A. The 660, the 658, the 577.
Q. What's the fourth?
A. Sorry about that, I misstated. I had the wrong note on here.
Q. What notes are you reviewing?
A. Just notes in my deposition prep. This is going back through all the pieces. You can have them.

Q. Thank you. So you're just telling me that they're actually -- you're saying that there were just -- there were three wells that you believe tested for oil in the San Andres?
A. Correct.
Q. If I were to look at the well completions and perforations for those wells, I would be able to discern the deepest interval from which they tested for oil?
A. It should be determined where the perf is on them; right, I suspect.
Q. Do you have that information in your notes there?
A. No, I don't.

hydrocarbons that can be economically recovered through tertiary recovery?
A. In this cross section?
Q. Yep.
A. We believe down into the San Andres there. I don't know exactly which depth on those curves that there is, you know, a ROZ zone to be -- of oil to be recovered through tertiary production.
Q. Do you believe that it extends below this dolostone interval?
A. Yes.
Q. How far below the dolostone interval?
MS. HARDY: Form and foundation. Objection.
Q. (By Mr. Rankin) You can answer.
A. I can't tell from this cross section.
Q. Okay. All right. I will leave this cross section for now. I'm going to try another one. Let me stop sharing for a moment. Mr. West, have you reviewed Preston McGuire's testimony that was submitted in this case?
A. I've seen some of his testimony.
Q. I'm going to show you what's -- was marked as his Exhibit B9. Okay. This is a cross section that Mr. McGuire prepared that shows the EMSU 460 well, which we were looking at on Mr. McShane's Exhibit G7 (a) on the left-hand side, and it goes from left to right to the banks, Goodnight

Midstream's banks SWD well, to the Sosa SWD well, to the Dawson SWD, Ryno SWD and on the far right is the EMSU 462, which is another water supply well that was used to supply water for the water flood. Do you see that?
A. I see the cross section.
Q. Okay. Do you agree with that, the EMSU 462 was also a water supply well that was used to supply water for the water flood in the EMSU?
A. Yes, sir.
Q. Okay. Now, on this map, on this cross section, Mr. West, there are subsea depths on the right and left side. Do you see that?

REBUTTAL EXHIBIT C-14

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

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC TO AMEND ORDER NO. R-7765 AS AMENDED TO EXCLUDE THE SAN ANDRES FORMATION FROM THE UNITIZED INTERVAL OF THE EUNICE MONUMENT SOUTH UNIT, LEA COUNTY, NEW MEXICO.	**CASE NO. 24278**
APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC TO AMEND ORDER NO. R-7767 TO EXCLUDE THE SAN ANDRES FORMATION FROM THE EUNICE MONUMENT OIL POOL WITHIN THE EUNICE MONUMENT SOUTH UNIT AREA, LEA COUNTY, NEW MEXICO.	**CASE NO. 24277**
APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS, LEA COUNTY, NEW MEXICO.	**CASE NOS. 23614-23617**
APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO.	**CASE NOS. 24018-24027**
APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22024/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO.	**CASE NO. 23775**
APPLICATION OF GOODNIGHT PERMIAN MIDSTREAM, LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.	**CASE NO. 24123** **ORDER NO. R-22869-A**

EMPIRE NEW MEXICO LLC'S RESPONSE TO GOODNIGHT MIDSTREAM PERMIAN LLC'S FOURTH SUBPOENA DATED JANUARY 3, 2025

Empire New Mexico, LLC ("Empire") submits the following responses to the Subpoena issued on January 10, 2025 at the request of Goodnight Midstream Permian, LLC ("Goodnight"). A link to responsive documents is provided in the email transmitting this response.

1. <u>Request No. 1:</u> All documents and data relating to corrosion encountered in each of Empire's EMSU wells that Empire contends is caused in whole or in part by Goodnight's saltwater disposal. If already produced, cite to the documents by bates

<u>Response:</u> Empire objects to Request No. 1 as duplicative of Request Nos. 3 and 4 in Goodnight's Third Subpoena Dated July 2, 2024, *inter alia*. See Empire's responses and documents produced in response thereto, including but not limited to Bates #s OCD 23614-17 03538-3557. In addition, Empire produces additional documents that can be found in the link provided concurrently in the subfolder entitled "Item 1 – Corrosion" under "4th Subpoena" and in the subfolder entitled "Chemicals" under "10_Item for Goodnight JAN 2025→West."

2. <u>Request No. 2:</u> All documents and data relating to premature and irregular encroachment of water or any other kind of water encroachment that Empire contends reduces or will tend to reduce the total ultimate recovery of crude petroleum oil or gas or both from the Grayburg or San Andres formations that Empire contends is caused in whole or in part by Goodnight's saltwater disposal. If already produced, cite to the documents by bates.

<u>Response:</u> Empire objects to this request as vague, ambiguous, and overly broad because, for example, responsive documents include documents that are responsive to Requests Nos. 1 and 3 herein. Moreover, this request is duplicative of numerous previous discovery requests and previously produced documents, including but not limited to Bates #s OCD 23614-17-04508 and -5439. In further response, Empire fully incorporates its responses to Request Nos. 1 & 3 herein and responses to Goodnight's previous subpoenas, including but not limited to Request No. 6 in its September 22, 2023 Subpoena and Request No. 14 in its March 5, 2024 Subpoena. In an effort to ensure that Goodnight has any document that it believes may be remotely related to this request, Empire produces one additional document, which can be found in the subfolder entitled Item 2 – Water Encroachment.

3. **Request No. 3:** All water analyses performed for the EMSU from 2020 to the present, including but not limited to (1) produced water from Grayburg producers; (2) water injected into Grayburg waterflood injectors; (3) water injected into the EMSU SWD #1; and (4) water produced from any of the EMSU water supply wells. If already produced, cite to the documents by bates for each forgoing category.

Response: Empire objects to this request as duplicative of previous Goodnight requests, which include but may not be limited to Request Nos. 5 and 6 in Goodnight's March 2, 2024 Subpoena. Empire fully incorporates its responses to Goodnight's previous discovery requests relating to the same subject matter, including but not limited to the Water Samples produced unnumbered on December 4, 2024. In an effort to ensure that Goodnight has any document that it believes may be remotely related to this request, Empire produces additional documents that may be found in the subfolder entitled Item 3 – Water Analyses at the link provided concurrently.

4. **Request No. 4:** Updated daily water injection volumes and wellhead pressures for Empire's EMSU waterflood injection wells.

Response: Responsive information was produced and filed as Notice of Filing Verified Accounting of Waterflood Injections on January 14, 2024.

5. Request No. 5: All documents and data, including communications or correspondence of any kind, relating to skim oil produced or collected from any of the EMSU water supply wells.

Response: Empire has conducted a diligent and thorough search of the records within its possession, custody, or control and discovered no responsive documents or data.

6. Request No. 6: Empire's EMSU evaluation file, including but not limited to all documents and communications relating to Empire's due diligence leading up to the purchase of the EMSU and all documents provided to Empire by XTO.

Response: Empire objects to this request, which has been repeated numerous times, including but not limited to Request No. 7 in Goodnight's Subpoena issued July 2, 2024. Empire incorporates its responses thereto, as well as its response to Goodnight's other related requests. In an effort to ensure that Goodnight has any document that it believes may be remotely related to this request, Empire produces additional documents that may be found in the subfolder entitled Item 6 – EMSU Evaluation File. *See* Index.

7. Request No. 7: All documents and data, including draft or final authorizations for expenditure, and communications or correspondence of any kind, including to/from EMSU working interest owners, relating to proposed new wells targeting the San Andres formation within the EMSU.

Response: Empire has conducted a reasonable search and determined that no responsive documents exist.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served on the following by electronic mail on January 20, 2025.

/s/ Sharon T. Shaheen

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Attorneys for Intervenor Goodnight Midstream, LLC

Mr. West, are you aware of any primary production occurring below this blue dolostone anywhere within the unit below that depth, anywhere -- correlative depth anywhere in that unit?
A. Can you tell me what subsea depth you have there?
Q. You don't have subsea depths on these exhibits, so I cannot give you a subsea depth.
A. I'll have to convert the depths. I can't really read the depths on this, these logs.
Q. Let me ask you this: Are you aware of any primary production within the San An- -- within the EMSU unit from within or below the interval that was completed by the water supply wells?
A. This is the 660; is that correct?
Q. The 460.
A. 460. There's -- there's been four wells in the EMSU that's, you know, tested oil in the San Andres.
Q. Which are those?
A. The 660, the 658, the 577.
Q. What's the fourth?
A. Sorry about that, I misstated. I had the wrong note on here.
Q. What notes are you reviewing?
A. Just notes in my deposition prep. This is going back through all the pieces. You can have them.

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Q. Thank you. So you're just telling me that they're actually -- you're saying that there were just -- there were three wells that you believe tested for oil in the San Andres?
A. Correct.
Q. If I were to look at the well completions and perforations for those wells, I would be able to discern the deepest interval from which they tested for oil?
A. It should be determined where the perf is on them; right, I suspect.
Q. Do you have that information in your notes there?
A. No, I don't.

hydrocarbons that can be economically recovered through tertiary recovery?
A. In this cross section?
Q. Yep.
A. We believe down into the San Andres there. I don't know exactly which depth on those curves that there is, you know, a ROZ zone to be -- of oil to be recovered through tertiary production.
Q. Do you believe that it extends below this dolostone interval?
A. Yes.
Q. How far below the dolostone interval?
MS. HARDY: Form and foundation. Objection.
Q. (By Mr. Rankin) You can answer.
A. I can't tell from this cross section.
Q. Okay. All right. I will leave this cross section for now. I'm going to try another one. Let me stop sharing for a moment. Mr. West, have you reviewed Preston McGuire's testimony that was submitted in this case?
A. I've seen some of his testimony.
Q. I'm going to show you what's -- was marked as his Exhibit B9. Okay. This is a cross section that Mr. McGuire prepared that shows the EMSU 460 well, which we were looking at on Mr. McShane's Exhibit G7 (a) on the left-hand side, and it goes from left to right to the banks, Goodnight

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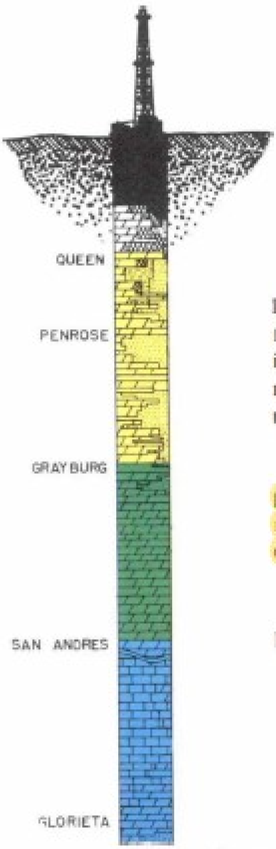
Midstream's banks SWD well, to the Sosa SWD well, to the Dawson SWD, Ryno SWD and on the far right is the EMSU 462, which is another water supply well that was used to supply water for the water flood. Do you see that?
A. I see the cross section.
Q. Okay. Do you agree with that, the EMSU 462 was also a water supply well that was used to supply water for the water flood in the EMSU?
A. Yes, sir.
Q. Okay. Now, on this map, on this cross section, Mr. West, there are subsea depths on the right and left side. Do you see that?

HOW CAN WE EXTEND THE LIFE OF THIS FIELD — 1929 TO ______

As with all oil fields, production has declined with time. In 1979, the Working Interest Owners (companies operating the wells and paying the maintenance costs) began a series of meetings and engineering studies to attempt to extend the productive life of this field by recovering oil that can never be produced with the present method of operation and existing facilities.

REBUTTAL EXHIBIT C-15



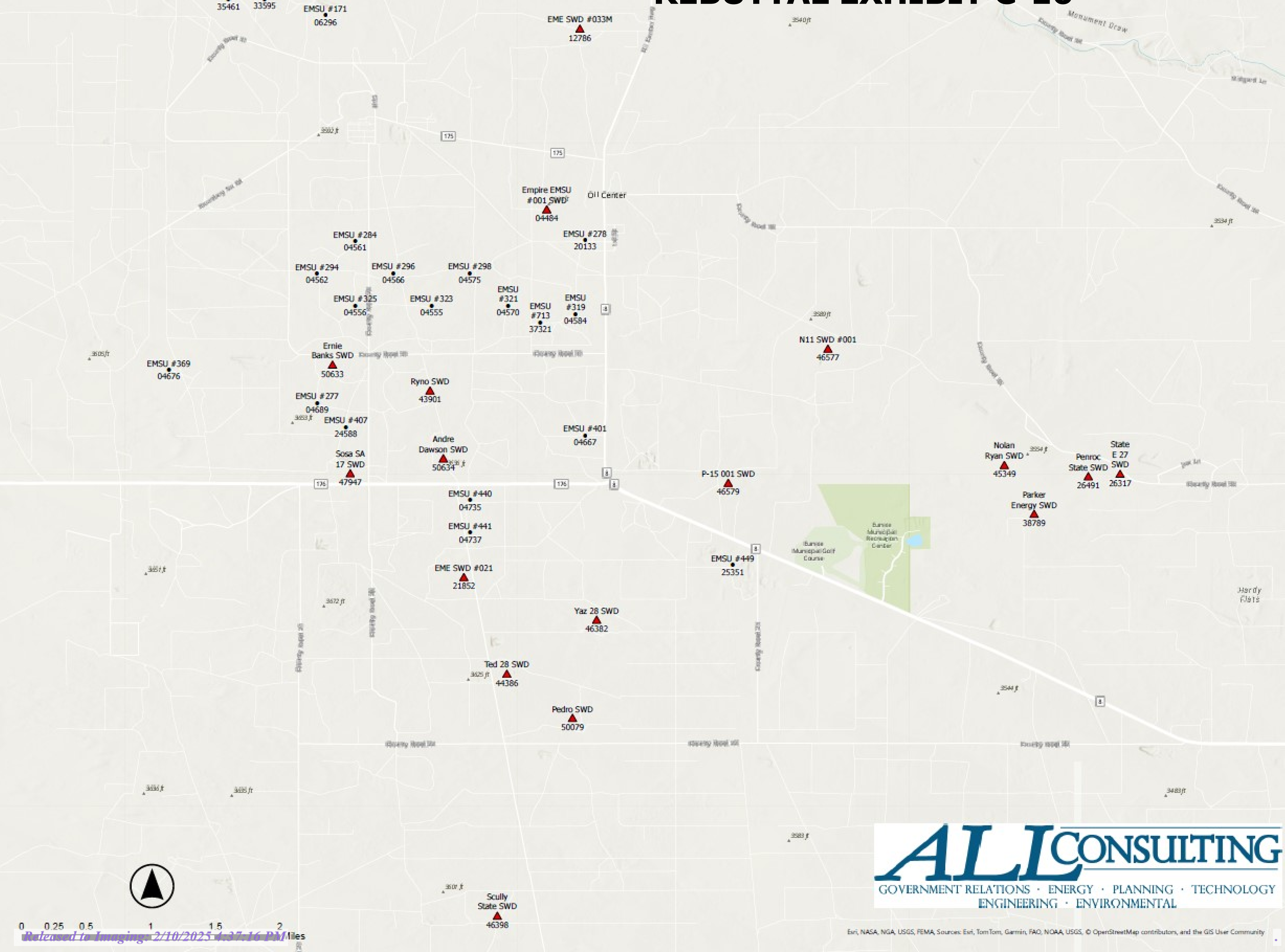
WATER INJECTION

After the various company geologists and engineers completed their laboratory and reservoir studies, they concluded that a unit should be formed to inject water into the oil producing formations to force oil trapped in the rocks to the pumping units of the producing wells. This method of recovery is being successfully employed in many of the older oil fields in the area

For this proposed unit, salt water from the non-productive San Andres formation, supplemented by the reinjection of produced water, was recommended for pressurized injection into the oil producing portions of the Grayburg and Lower Penrose formations.

To understand the benefits of water injection, a brief discussion of primary and secondary recovery is helpful.

REBUTTAL EXHIBIT C-16



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REBUTTAL EXHIBIT C-17

Is it your testimony that chemicals from Delaware Basin fracture treatments are causing corrosion in your wells?

A. So chemicals from fracture treatments are, again, unknown chemicals that are coming into the mix, and they can cause -- there can be gels and if they react with iron, they can crosslink and cause gumming and gelling that could happen.

There's also, you know, fluids that could be put in there, acids or different things that are, you know, corrosive, more corrosive.

You -- they change the pH on frac jobs a lot. You tweak it up, you tweak it down. So you change the pH of the water, you greatly change the chemistry, which, you know, will lead to either corrosion or scaling or different things. It depends on the exact makeup.

Q. Okay. You mentioned -- have you identified any specific instances where you've had issues with EMSU wells that you attribute to any of those potential symptoms that you just referenced?

A. Any failures of potential symptom, right? It'd be potential. It's a creep over time on it, but no one would ever say, hey, I'll go take a bunch of frac water to go do a waterflood with.

Q. Have you been tracking well failures in the EMSU?

A. Yes. We have well failures tracking with AFEs, and then we've got -- when we repair them, we had the documentation and, you know, what was failing. And always working on improving that program.

Q. You said -- I may have missed what you said. When we have repairs, we have documentation, and then you said something that dropped off, I couldn't quite pick it up.

A. You have documentation of the well work that was done. Hey, this part failed, this is what happened. You know?

Q. So Empire has documentation of all that, correct?

A. You have documentation of the well work that was done.

Q. Right. And the costs associated with them?

A. And the cost that is associated with them.

REBUTTAL EXHIBIT C-18

Is it your testimony that chemicals from Delaware Basin fracture treatments are causing corrosion in your wells?

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Q. So Empire has documentation of all that, correct?

A. You have documentation of the well work that was done.

Q. Right. And the costs associated with them?

A. And the cost that is associated with them.

Q. Okay. All right. I will come back to that.

We talked -- I think the next bullet point we kind of touched on already, some of the increased failure rates, is something that Empire is tracking, right?

A. We're tracking, yes, of all the well work and failures that happen.

Q. Is there any specific evidence that you cite to or point to in your testimony that supports or links any well failures to the disposal from Goodnight Midstream in your testimony or exhibits?

A. You could -- just the increase in salinity and, you know, this causing -- increases the cause of those problems.

Q. So in your evidence, testimony and evidence that -- where you present evidence where there's -- showing an increase in salinity in the Grayburg formation; is that right?

A. Other produced fluid?

Q. Okay. That's the indication that you're relying on to show that there's a -- Empire -- Goodnight's contributing to increased well failures?

A. Yes. You know, increased salinity will increase corrosion, which will increase well failures.
Q. We move to the next bullet here.
"By CO2 flooding the San Andres ROZ interval, it is estimated that 270 million barrels of this residual oil can be recovered."
I'll stop there. Did I read that portion of the sentence correctly?
A. Yes, sir.
Q. Now, I just want to get down to a couple things on this point.
The 270 million barrels, where does that number come from?
A. That comes from estimates like on the economic page of the different floods in the -- taken the, you know, the gross interval of the 400 and the dimensional curves and things that we went over.
Q. Okay. So when I pull up -- I think I'll pull it up, okay? Let me stop sharing so I don't have to -- I'll use the 250 pattern analysis that you prepared.
And tell me if I should use the 75 pattern analysis. It's taking a little while

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

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO

CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO.

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24020, 24025

APPLICATION OF GOODNIGHT PERMIAN MIDSTREAM, LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.

DIVISION CASE NO. 22626
ORDER NO. R-22869-A
COMMISSION CASE NO. 24123

SELF-AFFIRMED REBUTTAL STATEMENT OF JAMES A. DAVIDSON

1. My name is James A. Davidson. I work for Netherland, Sewell & Associates, Inc. ("NSAI") as Vice President and Senior Technical Advisor. I have been with NSAI since 1998.

2. I provided direct written testimony in these cases that were filed with the Commission on August 26, 2024, on behalf of Goodnight Midstream Permian, LLC ("Goodnight"). I have been asked to prepare rebuttal testimony in response to Empire's

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. D
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

petrophysical models and analyses regarding the potential for a productive residual oil zone ("ROZ") in the EMSU. This includes a petrophysical evaluation of geological barriers that isolate Goodnight's disposal zone in the San Andres from the overlying Grayburg formation.

3. This rebuttal statement summarizes my analysis and opinions to date. I reserve the right to amend or supplement this report, if necessary, should additional information become available to me, and to rebut any related opinions reached by experts related to these cases. All the opinions and conclusions herein are rendered to a reasonable degree of professional certainty.

Summary

4. The following are my basic conclusions derived from the petrophysical analysis of the Grayburg and San Andres Formations in the area occupied by the Eunice Monument South Unit.

- At this point, oil and water saturation estimates have been provided by Empire for three different petrophysical models. There appears to be a disagreement between the Empire geologist and their petrophysical expert as to which of the three models best represents reservoir conditions.
- The latest NuTech petrophysical model from Empire, that I have been able to review, was calibrated to the raw water saturation measurements from EMSU 679. The raw core water saturations, however, are too low as the result of water expulsion from dissolved gas expansion in the residual oil during core retrieval. The log-derived water saturation estimates from Empire are therefore too low. This leads to optimistic oil saturation estimates in the San Andres formation and an overestimation of the oil-in-place. Intervals in the upper San Andres have been erroneously identified as having the characteristics of a Trentham-Melzer ROZ enhanced oil recovery target.

- There is evidence from loss circulation events during drilling operations that barriers 90 feet or deeper below Goodnight's pick for the top of the San Andres are isolating Goodnight's water disposal operations from Empire's shallower waterflood operation in the Grayburg. It does not appear that the interval existing above the barriers is in pressure communication with the water disposal zone below the barriers.
- Evidence indicates that oil saturations measured in the core from NMGSAU 522 do not appear to be representative of true reservoir conditions as the result of the documented presence of lease crude in the drilling mud used during the coring operations.
- My independent review and analysis of the information available, including Empire's expert witness testimony and the data and information they rely on, supports my original analysis and conclusions outlined in my direct written testimony, dated August 16, 2024:
  - The saturation profile in the San Andres aquifer is more likely representative of abandoned oil migration pathways than of a previous oil-saturated interval.
  - Thick, impermeable anhydrites and anhydritic dolostones found near the top of the San Andres aquifer appear to effectively isolate the water disposal intervals in the Goodnight operated wells from the overlying Grayburg residual oil zones.
  - Given the sparse nature of the residual oil accumulations and the presence of significant karsting, Goodnight's San Andres disposal zone does not meet any reasonable definition of an ROZ.

<u>Empire's Petrophysical Models</u>

5. **Three different petrophysical models have been prepared by NuTech for selected wells from the Eunice Monument Unit (EMSU). The first two models utilized a simple water saturation model employing constant electrical conductivity parameters**

(cementation exponent, m and saturation exponent, n). The models did not account for the complex electrical conductivity behavior of the different carbonate rock types known to be present in the San Andres formation. The models were not calibrated to the core data available from EMSU 679. I pointed out in my direct testimony that a model employing variable electrical conductivity parameters was necessary for accurate water saturation modeling. The NuTech models consistently overestimated the oil saturations in the EMSU and predicted the presence of mobile oil in intervals that well test data indicated produced 100 percent water. It was acknowledged by NuTech that well test data were not considered in the model development.

6. **A third model was provided by NuTech that had been prepared at the request of Empire. The model did employ variable m and n values and was calibrated to the raw, uncorrected water saturation measurements from the core data from EMSU 679. The core water saturation measurements used for the calibration were not corrected for water loss resulting from the expansion of gas dissolved in the oil. The evolution of dissolved gas would have occurred as the result of pressure decreases within the core that occurred when the core was retrieved from the well. The underestimation of water saturations resulted in the overestimation of the oil saturations.**

NuTech Model Possibly Prepared for XTO (NuTech1)

7. Petrophysical Interpretations for several EMSU wells were included in Empire's written testimony prepared by Mr. Cestari for the Nov. 2, 2023 hearing that was originally scheduled with the Oil Conservation Division ("OCD"). In reviewing the interpreted log images, it was observed that the images in Mr. Cestari's testimony did not match some of the interpretations that were provided to Goodnight in the spring of 2024. Apparently a second interpretation had

been prepared for Empire. Presumably, the first interpretation might have been performed for XTO in preparation for the sale of the EMSU. Section-level oil in place estimates were provided in Mr. Cestari's written testimony of Oct. 26, 2023. It is not clear which NuTech interpretation was used to prepare these oil-in-place estimates. I discovered the discrepancy between the NuTech interpretations in the spring of 2024 and requested digital analysis output curves so that comparisons could be made between the two interpretations. I did not receive digital copies of the first NuTech interpretation curves until Jan.13, 2025. Digital log data was not provided. Only images of the interpretations were provided.

NuTech Model Originally Prepared for Empire (NuTech2)

8. I was provided with NuTech interpretations presumably prepared for Empire for 10 wells during the spring of 2024. These curves were used for model interpretation comparisons in my Aug. 16, 2024 written testimony. During Mr. Dillewyn's deposition on Dece. 17, 2024, he was questioned concerning the two NuTech interpretations. He stated that the reason for the two versions was that Empire provided updated tops that needed to be incorporated into the zone-average saturation and porosity values reported for the analysis. Figure 1 shows an example comparison of the first NuTech interpretation of March 22, 2006 and the second NuTech interpretation dated September 29, 2023. Notice that the lithology interpretation changed as well as the fluid saturation and permeability interpretations. It appears that the first and second interpretations are two independent interpretations of the same data. It is not clear what changed other than the operator of the EMSU. It is interesting to note that the oil saturations significantly increased in the NuTech interpretations prepared for Empire compared to the interpretations prepared for XTO.

September 2024 Sensitivity Analysis

9. Empire submitted an analysis of the sensitivity of NuTech's EMSU petrophysical model to variations in the cementation exponent, m, and saturation exponent, n, that NuTech prepared in September 2024. A study sponsored by the National Energy Technology Laboratory using core and well log data collected in four nearby counties (Kuuskraa et al., 2020) was used to define expected ranges in the m and n values for the analysis of ROZ saturation in the Grayburg and San Andres formations in EMSU 679. In the sensitivity analysis, four pairs of m and n values reported in the study were evaluated. It was demonstrated that better matches between the well log-derived water saturation estimates and the raw core water saturation measurements could be obtained when the m and n values were varied through the cored interval. While better matches to the core water saturation measurements were obtained using variable m and n values, NuTech concluded that the variable m and n scenario was unlikely because the log character did not change through the cored interval. In his deposition (December 17, 2024), Mr. Dillewyn stated that he believed that the original interpretation (NuTech2) using constant m and n values of 2 and 2 best represented the expected reservoir conditions. Excerpts from his deposition are provided in Figure 2.

10. During Mr. Dillewyn's deposition I learned that NuTech was not provided with the core data from EMSU 679 at the time the NuTech2 model was being developed. Mr. Dillewyn also testified that well test and longer-term production data were not considered during the development of the NuTech2 model as shown in Figure 2. He stated that test and production data were not provided to NuTech by Empire for any of the wells for which NuTech log interpretations were prepared. Test and production data are publicly available on the New Mexico OCD website. It should be standard practice to validate the results from a petrophysical model with well

performance data. Preston McGuire pointed out in his direct written testimony dated Aug. 26, 2024 that the water saturation values computed with the NuTech model (here referred to as NuTech2) are incompatible with available well test and long-term production data. Mobile oil is interpreted in multiple intervals that produced 100 percent water.

11. It should be noted that this sensitivity analysis was received by Goodnight on October 31, 2024, with no explanation.

Revised NuTech Interpretation Prepared for Empire (NuTech/Empire)

12. Revised direct written testimony from Mr. McShane was received on Dec. 8, 2024, well after the Aug. 26, 2024 deadline for submission of written direct testimony. The revised direct written testimony contained updated log interpretations from NuTech for 7 wells. The revised interpretations incorporated the variable m and n values discussed above. For the purposes of this rebuttal statement, this revised NuTech interpretation will be referred to as the "NuTech/Empire interpretation".

13. During Mr. Dillewyn's deposition, he provided an overview of the process used to assign the various m and n pairs during the sensitivity analysis discussed above. He testified that at Empire's request, the variable m and n solution was applied to the 7 subject wells. When questioned in his deposition about what criteria were used to change the m and n values as a function of depth for the wells that did not have core measurements, he stated that NuTech's petrophysical interpreter had identified changes in log character in the gamma ray, neutron and bulk density log measurements that characterized the locations where the changes were needed. This is in contradiction to his statement that "the variable m and n scenario was unlikely because the log character did not change through the cored interval" (NUTECH, 2024). As stated before,

it appears that NuTech and Empire have different opinions concerning which of the two most recent NuTech models best represents actual reservoir conditions.

14. **Revised section-level oil-in-place estimates for 7 wells were provided in revised direct testimony from Mr. McShane provided in December of 2024. The revised oil-in-place values were on average 40 percent of the volumes initially reported in Mr. Cestari's direct testimony in November 2023. It is not clear which of the two original NuTech models were used for these initial estimates. I believe the oil-in-place number reported by Mr. Cestari most likely came from the second NuTech model (NuTech2) because it interpreted higher oil saturations. Based on my modeling, the average oil-in-place estimates are only about 14 percent of the estimates derived from the revised NuTech model (NuTech/Empire). There are three reasons for the differences. There is disagreement between Empire and Goodnight concerning the location of the top of the San Andres formation, the revised NuTech model overestimated the oil saturations in the 7 wells, and it appears that Empire did not apply water saturation cut-offs when computing the oil-in–place estimates. In my model (labeled NSAI in the rebuttal document), an 80 percent water saturation (20 percent oil saturation) cut-off was applied to eliminate intervals containing very low oil saturations from the oil-in-place estimates. These low saturation intervals will not likely contribute to commercial production.**

15. **It is my opinion that the intervals containing residual oil in the upper part of the San Andres formation do not exhibit the oil saturation versus depth profile expected for an ROZ interval as defined by Dr. Trentham. The short intervals containing elevated residual oil saturations in the San Andres appear to be abandoned paleo oil migration pathways. The section-level oil-in-place estimates above assume 100 percent areal coverage**

of the oil. If the residual oil in the San Andres is indeed associated with paleo migration pathways, the actual oil in place would be a small fraction of the values reported for the NSAI model. The oil would exist in narrow, meandering pathways through the better reservoir quality rock.

16. In Mr. McShane's revised direct written testimony, updated oil in place estimates were provided for the 7 wells that were re-analyzed by Nutech using the sensitivity analysis. A comparison of NSAI's oil in place estimates to the original estimates generated from NuTech2 and the revised estimates from NuTech/Empire are summarized in the table below.

	OIP (MMBO/sec)		
Well	NSAI	Nutech	Nutech Revised
EMSU 628	6.8	89.4	40.8
EMSU 658	0.0	60.9	30.3
EMSU 660	2.7	98.1	48.6
EMSU 673	3.1	61.1	31.7
EMSU 713	0.0	13.6	8.0
EMSU 746	13.3	174.5	62.2
Ryno 1	6.9	91.5	15.6
Total	32.8	589.1	237.2

17. It is not clear what cut-offs for porosity, shale volume, and water saturation were employed in the oil in place estimates reported by Empire (NuTech and NuTech Revised). It is also unclear what tops were used to define the in-place estimates. The column labeled NSAI is based on a water saturation cut-off of 80 percent (oil saturation cut-off of 20 percent) and a porosity cut-off of 7 percent. The NSAI in-place values are for the San Andres interval using tops provided to NSAI by Goodnight. All of these oil-in-place estimates assume 100% areal coverage of oil within a section. In fact, many of the zones with elevated oil saturations within the San Andres may be abandoned migration paths. If so, even NSAI's oil-in-place estimates may be significantly overstated.

OPS Geologic Model

18. On Jan. 7, 2025, I was informed that Empire has added a consulting petrophysicist to their list of rebuttal witnesses for the upcoming February Oil Conservation Commission hearing. Mr. Scott Birkhead was added to the witness list. It appears that yet another petrophysical model may be introduced by Empire. Unfortunately, I am in no position to comment on a model that I have not seen. To my knowledge, Goodnight has not had the opportunity to conduct a deposition with Mr. Birkhead or to review his new analysis or conclusions.

Oil Saturation Cut-Off

19. **It is industry standard practice to apply water saturation cut-offs when calculating oil-in-place. The cut-off is intended to eliminate intervals containing very low saturations where the oil that is likely immobile from the in-place estimates. All of the oil in the intervals with water saturations below the water saturation cut-off are included in the oil-in-place estimates. By handling in-place estimates in this manner, recovery factor estimates reported in the industry have a common basis in mobile oil.**

20. **The 20 percent oil saturation cut-off applied in the NSAI oil-in-place estimates was derived from oil saturation estimates derived with the NSAI petrophysical model with log data from the Seminole San Andres Unit (SSAU). Oil saturations were computed for a well drilled in a well-swept area that had been under CO_2 enhanced oil recovery operations for over 40 years.**

21. **The United States Geological Survey has published recovery factor estimates for the SSAU covering the primary, waterflood and CO_2 injection oil recoveries. An analysis of the reported oil recovery volumes showed that the residual oil saturation in the portions of the field contacted by CO_2 enhanced oil recovery operations would likely be somewhere**

between 19.6 and 22.4 percent. This is in good agreement with the 20 percent residual oil saturation derived from the well log analysis. It is interesting to note that Dr. Trentham also appears to use a 20 percent oil saturation cut-off in his definition of an ROZ interval.

22. **Much of the San Andres formation in the area near the EMSU is interpreted to have been originally deposited in a deep-water environment where organic matter in the sediments would likely have been preserved. Much of the "oil" in the intervals interpreted as having low oil saturations may in fact be immobile organic matter composed of solid hydrocarbons.**

23. During my deposition, I was asked by Empire's counsel why I used an oil saturation cut-off in the section-level oil-in-place estimates generated from my well log analysis results. The implication of the questions was that oil-in-place should not be limited by cut-offs. First of all, it is industry standard practice to apply porosity, shale volume, and water saturation cut-offs when quantifying oil-in-place. The concept is that oil that will not possibly be mobile under standard oil field operations (primary, secondary, and tertiary recovery) should not enter into the oil-in-place evaluation because it will not be recovered. Under normal conditions, the porosity and shale volume cut-offs are designed to remove non-reservoir quality rock from the in-place estimates. The water saturation cut-off is meant to remove intervals where the oil saturation is too low to be mobile. All the oil in intervals that pass the cut-off criteria is included in the oil in place estimates. Enhanced oil recovery methods are designed to mobilize oil that would otherwise be immobile under waterflood operations. Therefore, higher water saturation cut-offs may be considered as the result of the potential mobilization of oil that would otherwise be immobile, justifying an 80 percent water saturation cutoff.

24. In my original direct written testimony dated Aug. 16, 2024, I utilized a 20 percent oil saturation cut-off (80 percent water saturation cut-off) for my well-level oil-in-place estimates. This value was derived from observations of the oil saturation estimates derived for SSAU well 4113R which was drilled as a part of the ROZ development program initiated by Hess at the Seminole San Andres Unit and adopted by Empire's own expert witnesses. A discussion of this well is included in my direct written testimony. The Seminole San Andres Unit (SSAU) had been under CO_2 enhanced oil recovery operations for over 40 years at the time SSAU 4113R was drilled. The calculated oil saturations in the main producing zone (MPZ) which had undergone long-term CO_2 flooding was about 20 percent through the majority of the interval above the water-oil contact. Honarpour et al. (2010) reported that laboratory CO_2 oil displacement tests with core plug samples indicated a residual oil saturation of about 12 percent. Such tests always yield optimistic oil recovery results because under core-flood conditions the CO_2 confinement, miscibility maintenance, flood front flow velocities, and pore volumes of fluid injected are always greater than possible under actual field conditions. In a core plug, it is possible to radially confine the CO_2 as it flows from one end of the plug to the other. In the reservoir, the CO2 finds the path of least resistance in the formation and oil in lower permeable sections of the formation may not be contacted. The observed 20 percent oil saturation values in the MPZ were predictions from my petrophysical model. This suggests that under actual long-term field operations, it was not possible to reduce the oil saturation to below 20 percent. The residual oil saturation from the well log analysis gives a more accurate representation of what portion of the oil will be mobile at the reservoir scale rather than the core plug scale.

25. Based on long-term performance data for the SSAU CO_2 EOR project published by U. S. Geological Survey (Olea, 2017), it is possible to independently verify the 20 percent residual

oil saturation estimate. The USGS study reported a recovery factor of 16.2 percent of the original oil in place for CO_2 flood EOR operations at the SSAU. Using the reported primary plus waterflood recovery factor (36.3 percent) published in the study, it was determined that the 16.2 percent of the total oil-in-place corresponds to 25.5 percent of the oil remaining in-place following waterflooding. Using these figures, a rough estimate of the volumetric sweep efficiency of the waterflood would be about 75 percent. This suggests about 75 percent of the pore volume between the water injection wells and producing wells was swept by water. Assuming CO_2 miscibility with the oil-water system was maintained and using the miscible fluid viscosity data provided in the Hess fluid-rock characterization study (Honarpour et al., 2010), it is possible to estimate the volumetric sweep efficiency of the CO_2 flooding operations at the SSAU. A volumetric sweep efficiency model proposed by ARCO Technology (Fassihi, 1986) was used to define a reasonable range of expected volumetric sweep efficiencies for the SSAU CO_2 EOR operations. A sweep efficiency range from 67 percent to 87 percent was estimated. This means that somewhere between 67 and 87 percent of the pore volume existing between the CO_2 injection wells and the producing wells could be expected to be contacted by the injected CO_2. Adjusting the 25.5 percent recovery factor to reflect the actual recovery for the fully contacted portions of the reservoir, a range in recovery factors from 29.3 to 38.1 percent is obtained. The average oil saturation in pressure core taken in the residual oil zone in the SSAU was 31.7 percent (Honarpour et al. 2010). Using the above recovery factors, the expected range in the residual oil saturation following CO_2 flooding would be from 19.6 to 22.4 percent. This is in reasonable agreement with the 20 percent value observed in the log analysis of the CO_2 swept zone in SSAU 4113R.

26. The long-term miscible displacement operations at the SSAU were not able to reduce the oil saturation to levels below 20 percent. This suggests that a combination of capillary

forces and intermolecular forces between the hydrocarbon molecules are strong enough to stifle miscibility at oil saturations below 20 percent. It was assumed for the oil-in-place calculations that intervals with interpreted oil saturations below 20 percent would likewise be immobile, even with CO_2 injection, and should not be included in the in-place estimates.

27. As mentioned in my original direct written testimony, many of the intervals composed of deeper water rock types associated with the carbonate ramp depositional environment may contain immobile solid organic matter or immature bitumen. This situation was discussed in detail in paragraphs 53 through 56 of my original written testimony from August 16, 2024. Organic matter was described in core samples from the EMSU-679 well near the bottom of the core intervals. Organic matter is soluble in the petroleum solvents used to extract oil in the lab and typically is included in the oil saturations in core analysis reports. The organic matter was described in samples with reported oil saturations less than 20 percent.

28. Figure 3 shows a photograph of organic matter in a San Andres core (Ramondetta, 1982) from the Northeast shelf.

29. Much of the "oil" interpreted in the deeper San Andres intervals where elevated gamma ray readings indicate that a deep-water environment is present may in fact be solid organic material. It is therefore reasonable to exclude intervals with estimated oil saturations below 20 percent for the oil-in-place estimates for the San Andres.

30. The stated purpose of Empire's project is to develop ROZ resources that may be associated with the EMSU. It would therefore be reasonable that the oil-in-place estimates prepared for this purpose would conform to Trentham's definition of an ROZ. Figure 4 is adapted from an exhibit prepared by Dr. Robert Trentham illustrating a defined ROZ interval and notes that oil saturations below 20% are not included in this interval.

<u>Fluid Losses During Coring Operations</u>

31. **Many of the problems with the most resent petrophysical model employed by Empire involve the lack of appropriate corrections to the raw core data from EMSU 679 prior to the calibration of the water saturation model. It is important to understand the mechanisms of fluid loss (oil, water and gas) that occur during coring. EMSU 679 was cored using a conventional coring bit and core barrel (conventional core). The core was collected beneath the oil-water contact in an interval where the oil would reside at residual saturation conditions and would therefore be immobile. There are three mechanisms for oil loss when coring an interval containing residual oil. The residual oil contains dissolved gas which expands when the core is brought to surface and the reservoir pressure is released. Gas expands with reduced pressure, expelling oil from the core (bleeding). The gas is lost to the borehole. The volume of oil in the core is reduced as the result of gas expulsion (shrinkage). In situations where there is a large pressure differential at the coring bit (for example when drilling into a highly pressure-depleted zone), high rates of mud filtrate invasion can strip residual oil due to viscous friction forces (stripping). As the gas expands, water is expelled from the core. At the conditions present in EMSU 679, the liberated gas volume would be 5 times or greater than the volume of the pores in the rock. At surface, the cores were only about 66 percent liquid-filled. Below the oil-water contact, they would be expected to be 100 percent liquid-filled. Clearly, liquid was expelled during core retrieval from the wellbore.**

32. **When precise measurements of the residual oil saturation in a reservoir are needed, for example when designing an enhanced oil recovery program, a pressure core is used. With a pressure core, reservoir pressure is maintained in the core barrel as the core is recovered to the surface. The volume of oil lost to bleeding is measured as gas is released in**

the lab. The oil and water remaining in the core following the removal of the gas is extracted and quantified. The volume of oil lost to shrinkage can be determined with measurements conducted with lease crude. Because there are no large pressure differentials at the bit with pressure coring, loss of oil to stripping does not occur.

33. Much of the discussion in the following sections of this document concern oil and water saturation measurements from cores. Following is a brief discussion of the reasons for fluid losses that often occur before the actual liquid saturation measurements are made in the laboratory.

Conventional Core

34. When water-based drilling mud is used as the coring fluid, mobile oil is displaced from the core during coring operations. The pressure of the water in the coring fluid is higher than the reservoir pressure and mud filtrate invades the core as it is being drilled. In many cases, mud filtrate invasion can reduce the oil saturation to near-irreducible levels. Therefore, oil saturations from cores cut above the oil-water contact where mobile oil exists are too low. During core retrieval, gas dissolved in the remaining oil expands as the pressure is released. The expanding gas causes some of the oil to be expelled (bleeding) and some of the water (which consists of formation water and drilling mud filtrate) to be expelled. The oil volume is also reduced as the result of the loss of dissolved gas.

35. For intervals below the oil-water contact (including suspected ROZ intervals), the oil would exist at residual saturation levels and would therefore be largely immobile from the standpoint of mud filtrate invasion. In some situations, when a large pressure differential exists near the coring bit due to highly depleted reservoir pressure conditions, high velocity mud filtrate invasion can reduce the residual oil saturation (stripping). During core retrieval, gas in the oil would expand which would displace some of the oil from the core. The evolving gas would

displace some of the water within the core as well. The volume of oil shrinks as a result of the lost dissolved gas. The oil saturations can be corrected back to reservoir conditions if the formation volume factor of the oil is known, and data is available to quantify the amount of oil lost to bleeding. Data from pressure cores (discussed below) or sponge cores from other wells from the same formation can be used to quantify the amount of oil lost to bleeding. The amount of water expelled depends on the relative amounts of oil and water present in the core at reservoir conditions. It is usually more difficult to quantify the amount of water expelled during core retrieval. Water is lost lost to evaporation during core transfer operations and laboratory handling. If rigorous sample weight records are maintained by the service company, corrections for these losses can be applied before the analysis results are reported. Some service companies do a better job of handling this than others. If reasonable corrections can be made to the oil saturations, it is usually assumed that the rock is liquid filled below the oil-water contact and the water saturation is calculated by simply subtracting the corrected oil saturation from 1.0.

Pressure Core

36. To overcome some of the saturation uncertainties discussed above, pressure coring was introduced. Pressure cores are generally cut when it is important to quantify residual oil saturation in reservoirs where waterflood operations have occurred. More recently pressure coring has been used to identify residual oil saturations in reservoirs where ROZ enhanced oil recovery projects are being considered.

37. With a pressure core, the reservoir pressure is maintained in the core barrel which minimizes the level of invasion of the coring mud filtrate. The cores are retrieved under pressure so the dissolved gas in the oil does not escape during core retrieval. Oil and water are therefore not expelled from the core. At the surface, the pressured core barrels are frozen to prevent loss of

dissolved gas. The cores are transferred to the core analysis lab in the frozen condition. When samples are cut from the cores for analysis, they are cut with liquid nitrogen so that the frozen state can be maintained. The samples are placed in containers and allowed to thaw. Thawing is often temperature-controlled so that the characteristics of the gas expansion in the lab simulate those that would occur when the core is retrieved from the well. The volumes of oil and water expelled from the core sample during thawing are quantified. Once thawing is complete, the samples are moved to fluid extraction chambers where heat and petroleum solvents are used to extract the remaining fluids from the core. The extracted oil and water volume are quantified. Using data from the pressure core it is possible to quantify the amount of oil lost to bleeding. The formation volume factor is generally obtained independently using a sample of reservoir oil. It is generally assumed that the water volume recovered at surface is representative of the water volume at reservoir conditions. Sometime tracers are added to the drilling mud so that the level of mud filtrate invasion can be quantified, and corrections can be applied to the lab-derived oil and water volumes. Water is lost lost during core transfer operations and laboratory handling. Some core analysis companies are better at correcting for these losses than others.

38. It is important to point out that most core analysis service companies report oil and water saturations in terms of the pore volume measured at laboratory stress conditions (usually between 300 and 800 psi). At reservoir conditions, the rock is under greater stress and the lab saturations need to be corrected for the pore volume reduction resulting from the increased rock stress in the reservoir. This correction is usually more significant for clastic (sandstone) reservoirs than carbonate reservoirs.

<u>Maljamar Pressure Core</u>

39. **In situations where both conventional and pressure core data are present, it is possible to develop rigorous core oil and water saturation correction procedures. Only conventional core data are available for the EMSU, however both conventional and pressure core data are available from the San Andres in the Maljamar field located in Northeast Lea County. Data from the Maljamar field was used to evaluate the correction procedure used to correct the raw oil and water saturation measurements from the core from EMSU 679.**

40. **At the time the NSAI petrophysical model was being developed, I was unaware of the core data that was publicly available from Maljamar 358. I used a "rule of thumb" model developed by my former employer (ARCO Oil and Gas Company) to correct the raw oil saturation measurements from the EMSU 679 core.**

41. We reviewed the four county petrophysical study used by NuTech in their sensitivity analysis and observed that a Department of Energy study was referenced describing a pressure core cut in the Grayburg-San Andres interval in the Maljamar field located in northwest Lea County (Swift et al., 1981). We obtained a copy of the DOE study and found that it contained valuable core analysis data for both the Grayburg and San Adres formations in a reservoir where the San Andres interval was cored both above and below the oil-water contact.

42. The Maljamar field is much shallower than the EMSU and the San Andres formation is located within a structural closure above the oil-water contact. The core was cut in Well No. 358 (also referred to as MCA 358) to quantify residual oil saturations existing above the oil-water contact following long-term waterflood operations. The core was cut for the purposes of evaluating the feasibility of a CO_2 injection pilot project.

43. In order to get the best estimates of the residual oil saturation present in the reservoir, a pressure core was cut. Tracers were added to the mud and tracer analysis at the laboratory indicated the invasion effects were minor. Core samples were cut from the frozen whole core sections and processed to determine volumes of oil and water following the procedure described in the previous section. At laboratory conditions, the volume of dissolved gas for these samples is 15 to 30 times the volume of the pore system and as the gas expands while the samples thaw, oil and water are expelled from the core samples.

44. Because the core was cut in a portion of the reservoir that had undergone long-term waterflooding, the core was assumed to have been 100 percent liquid-saturated at reservoir conditions. Fluid losses that might have occurred during surface handling of the core at the wellsite and laboratory operations were assumed to consist solely of oil losses by the core analysis contractor (Core Lab). The final oil saturations reported in the DOE report are consistent with this assumption.

San Andres Reservoir Wettability

45. **An oil–wet reservoir condition had been established for EMSU and the Seminole San Andres Unit. Standard core and log data crossplotting techniques were used to verify that the San Andres reservoir at Maljamar was oil-wet as well.**

46. The authors of the core analysis study at Maljamar noted that standard data analysis techniques indicated that the cores did not exhibit the behavior normally associated with a water-wet condition. A resistivity index versus water saturation crossplot was constructed using the measured formation water resistivity, the pressure core porosity, and water saturation measurements as well as the deep resistivity measurements from the open-hole logs for each core plug depth. The crossplot is shown in Figure 5. Asquith (2017) and Montaron (2007 and 2009)

have demonstrated that when the core data points consistently fall above the line representing a n value of 2.0 on this crossplot, an oil-wet condition is confirmed. A crossplot created from the corrected core water saturation measurements from EMSU 679 is shown in Figure 6. Note that the plots for Maljamar 358 and EMSU 679 are very similar to one another, and both exhibit the characteristics of an oil-wet condition. The analytical results reported by Honarpour et al. (2010) from the cores obtained at the Seminole San Andres Unit (SSAU) in the San Andres reservoir suggest that an oil-wet condition exists at the SSAU as well.

47. Unfortunately, the core analysis company (Core Lab) was not aware of the oil-wet condition and electrical property measurements (m and n) were made for selected samples with the cores prepared to represent a water-wet condition. The proper wettability restoration protocols were not followed, therefore the electrical property data reported in the DOE study are not likely representative of reservoir conditions.

<u>Potential Residual Oil Losses Due to High Differential Pressures at the Core Bit (Stripping)</u>

48. **Established modeling procedures were employed to evaluate the potential losses of residual oil due to high differential pressures at the coring bit for the conditions present at Maljamar 358 and EMSU 679. It was found that the reservoir permeabilities present at both wells were too low for oil stripping to occur.**

49. When large pressure differentials exist near the bit during coring operations, it is possible for portions of residual oil to be displaced as the result of high filtrate invasion velocities. This is usually not a problem with pressure cores but it can be a problem when a conventional core is drilled into a highly pressure-depleted interval. Calculations were performed for the conditions existing at Maljamar 358 and EMSU 679. The most extreme condition was tested where the core would be drilled into a highly pressure-depleted interval with a reservoir pressure of only 350 psi.

This would represent a pressure differential of about 1500 psi. Models developed by Jenks et al. (1968) and Stosur and Taber (1976) were used to determine the reservoir permeability above which differential pressure stripping would occur. The oil-wet condition of the San Andres reservoir was accounted for by using principles outlined by Lake (1989) and Gupta et al. (1979). It was found that permeabilities at least 5 times higher that present in the available core measurements from EMSU 679 and Maljamar 358 would be required to create filtrate invasion velocities sufficient to reduce the residual oil saturation by stripping. Therefore, oil loss resulting from differential pressure stripping would not be likely in the conventional cores cut at Maljamar 358 of EMSU 679.

<u>**Blind Test of the Water Saturation Models with the Maljamar Core Analysis**</u>

50. **The easiest way to verify the calibration of a petrophysical model is to run it for a well where good quality core data are available and check to see if the porosity, oil and water saturation estimates from the well log model agree with the core measurements. Two log interpretation models were developed by NSAI for the EMSU, one for use when sonic log measurements were available ("sonic mode") and another for situations where no sonic log data were available ("no sonic model"). These models were discussed in my direct written testimony. Sonic measurements were available for Maljamar 358. It was found that the oil and water saturation estimates from both NSAI models agreed well with the oil and water saturation measurements from the Maljamar 358 pressure core. Calculations were also performed using the model parameters employed for the revised model prepared by NuTech for Empire as well as the original models developed by NuTech. Both NuTech models overestimated the oil saturations measure from the core in the intervals below the oil-water**

contact that would be analogous to the conditions at the EMSU. This first check would seem to confirm that the core calibration of the NSAI model to EMSU was reasonable.

51. In my original direct written testimony, I described a model validation procedure where log data from a well drilled as a part of the ROZ development program undertaken at the SSAU were interpreted. The model returned oil saturation estimates through the known ROZ in the San Andres that were consistent with the pressure and sponge core oil saturation measurements reported by Hess (Honarpour et al. 2010). The pressure core data available from Maljamar 358 were used for a similar model validation check.

52. The lithology and porosity estimates from the model were in good agreement with the core descriptions and porosity measurements. Formation water resistivity estimates were derived using the same depositional sequence-based analysis procedure employed at the EMSU. Different water resistivities were identified for the Grayburg and San Andres formations. The log-derived water resistivity estimates were found to agree with water resistivities reported in the DOE study.

53. Sonic log measurements were available, so it was possible to perform water saturation calculations using the "sonic model" and "no sonic model" described in my direct written testimony. The log analysis results are displayed in Figure 7. Also displayed are the final oil saturation measurements from the core. Note that both the "sonic model" labeled NS_Sw_Sc_Lucia and "no sonic model" labeled NS_Sw_FINAL did a reasonable job of matching the oil saturation measurements from the core.

54. Calculations were performed using a model consistent with that used by NuTech and the m and n values reported in the four-county study discussed above. The gamma ray readings in the San Andres section of Maljamar 358 are very low indicating little or no clay content. In this

situation, the Simandoux model employed by NuTech would simplify to the standard Archie model. The m and n values from the study that would predict the highest water saturation (lowest oil saturation) values are 2.3 for m and 3.4 for n. These are the values used in the NuTech/Empire model (discussed above) for the San Andres interval in EMSU 679. A water saturation curve constructed using these m and n values is displayed in Figure 7 as Sw_NUTECH_REVISED. A curve consistent with the original NuTech model (m = n = 2) labeled Sw_NUTECH is also displayed. The oil-water contact for the San Andres interval in this well is posted on the log. Note that the standard Archie model using a constant m of 2.3 and n of 3.4 does a fairly good job of matching the core oil saturation measurements above the oil-water contact but consistently overestimates the oil saturations below the oil-water contact. Jerry Lucia from the University of Texas Bureau of Economic Geology has observed that the Archie model with constant m and n values often yields reasonable results compared to San Andres core data above the oil-water contact but generally overestimates oil saturations below the oil water contact (Lucia, 2000). It would be necessary to use higher m and n values below the contact to bring the log-derived saturations from the Archie model into agreement with the core measurements. The original NuTech model with m = n = 2 would have overestimated the oil saturations throughout the cored interval.

55. Empire will argue that their revised model did a good job of matching the core water saturations from EMSU 679. It will be shown that the core water saturations in EMSU 679 are too low. Water was expelled from the cores during retrieval to the surface and Empire should have instead calibrated to core oil saturations corrected for shrinkage and bleeding.

Quantifying Oil Expulsion (Bleeding)

56. **Sufficient detail was available in the core analysis report for Maljamar 358 to determine the average fraction of oil originally in place in the core that was lost to bleeding. It was determined that on average 19.2 percent of the oil was expelled due to dissolved gas expansion.**

57. The DOE study of the pressure core recovered from Maljamar 358 contained tables summarizing the plug oil and water saturation measurements recorded during the thawing and fluid extraction operations. As the core plug thaws, it comes into temperature and pressure equilibrium with the ambient laboratory conditions. Gas evolves from the core plug as the temperature increases displacing oil and water from the plug. This process mimics the gas evolution and expansion process that happens with a conventional (non-pressured) core as the pressure within the core is reduced while it is retrieved from the subsurface formation and brought to the surface. This data was used to estimate the fraction of the oil originally present in the core that was expelled due to the expansion of the dissolved gas. On average, 19.2 percent of the oil was expelled from the core because of dissolved gas expansion.

API Oil Gravity and Viscosity Differences Above and Below the Oil-Water Contact

58. **A residual oil zone (ROZ) as defined by Dr. Trentham was identified beneath the Seminole San Andres Unit. Hess, the operator, undertook an extensive coring and fluid analysis program to evaluate the feasibility of initiating a miscible CO_2 injection program in the ROZ. It was found that the API gravity and viscosity of the oil in the main production zone (MPZ) above the oil-water contact differed from the API gravity and viscosity of the oil in the ROZ below the oil-water contact. Apparently, the multiple pore volumes of flushing by meteoric water (Trentham's "Mother Nature's Waterflood") had degraded the oil**

properties. Data from the Maljamar 358 pressure core was used to validate the correction procedures used for the core data from EMSU 679. The pressure core from Maljamar 358 was acquired above the oil-water contact in the Maljamar Field. The core from EMSU 679 was acquired below the Grayburg oil-water contact in an area where multiple pore volumes of meteoric waters have likely passed through the San Andres. It was therefore necessary to consider the likely degradation of oil properties when adjusting the bleed fraction derived from the Maljamar pressure core to reflect the conditions present in EMSU 679.

59. Differences in API oil gravity and oil viscosity were observed above and below the oil-water contact in the SSAU during the analysis of the pressure core data (Honarpour et al. 2010). Above the oil water contact, the oil gravity was found to be 33 Deg. API with a viscosity of 1.0 cp. Below the oil water contact, the oil gravity was found to be 27.9 Deg. API with an oil viscosity of 2.4 cp. These findings are consistent with Trentham's concept of "Mother Nature's Waterflood" and an oil-wet condition in the San Andres formation.

60. **The oil-wet nature of the San Andres formation is due in a large part to the significant fraction of asphaltines present in the crude. In an oil-wet rock, oil coats the surfaces of the carbonate surfaces and water resides in the centers of the pore networks. Dr. Trentham has shown that oil present in paleo migration pathways and in residual oil zones that have been documented to be present beneath some of the hydrocarbon traps located in Southeast New Mexico and West Texas has been swept by multiple pore volumes of meteoric water originating from outcrops in New Mexico. Water sweep reduces the thickness of the oil film and preferentially displaces the lighter hydrocarbon components. The oil remaining in the film has a higher density (lower API gravity), higher viscosity and lower gas content than the crude oil which has migrated into the traps. This must be taken into account when**

correcting the bleed fraction determined from the pressure core recovered from Maljamar 358 to the conditions present below the oil-water contact at EMSU 679.

61. Water-filled carbonate reservoirs are originally water wet. Oil in the San Andres formation most likely originated in the deeper Wolfcamp formation and migrated upwards through major faults (Ramondetta, 1982). During migration, oil finds the path of least resistance as it moves upward due to the buoyancy force resulting from the difference in density between oil and water. During this migration, oil resides in the center of the pore network and is completely surrounded by a film of water which is in contact with the pore surfaces. Migration typically occurs through the portions of the formation with the highest permeability. In the San Andres, this would likely correspond to the grainstone and grain-dominated packstone interval (Kerans et al., 1994). Oil moves when a continuous pathway through the pore throats is established (Schowalter, 1979). Mercury injection capillary pressure curves from San Andres grainstone core samples indicate that a continuous flow path is established when the oil saturation reaches roughly 30 to 40 percent of the pore volume (Ghosh and Friedman, 1989). As long as the oil is moving, it remains in the center of the pores with the thin film of water residing between the oil and the pore surfaces. During migration of the oil between the faults and the shallower portions of the formation where the oil is trapped, the oil tends to move through narrow and irregular pathways through the higher permeability portions of the rock. Pathway heterogeneity is caused by macroscopic heterogeneity of the petrophysical properties of the formation through which migration is occurring. Modeling has shown that migration typically occurs only through a small fraction of the volume of the formation (Luo 2011). Outcrop studies have shown that there is extreme permeability heterogeneity in the San Andres formation (Kerans et al. 1994). Once migration ends and water begins to move through the formation, the remaining oil in the migration paths becomes

trapped in the center of the pores as the moving water displaces the oil from the pore throats. The trapped oil saturation would therefore be expected to be somewhere between 20 to 40 percent of the pore volume of the higher permeability rock within the migration path. Once the trapped oil becomes static, the weak electro-static van der Waals forces at the carbonate grain surfaces can begin to act on the oil. Van der Waals forces are the forces that hold water droplets on the surfaces of a shower wall. Polar components (compounds composed of molecules with positive and negative ends) within the oil are attracted by the electro-static forces at the pore surfaces and the oil slowly begins to coat the carbonate grains. Eventually, the oil completely coats the grains and the water moves to the center of the pores. The rock becomes oil-wet. Micropores within the rock can remain water-wet as the result of the strong capillary forces binding the water to the pore surfaces. The larger mesopores and macropores usually become oil wet as the result of contact with the residual oil. When both wettability conditions exist, the rock is said to have mixed wettability.

Reduction of the Original Trapped Oil Saturation

62. In the oil film on oil-wet carbonate grain surfaces, the heavier, polar components move toward the pore surfaces as the result of the electro-static attraction while the lighter, non-polar components migrate toward the water-oil interface. The oil at the oil-water interface is lighter in density and less viscous than the heavier components near the grain surfaces. In experiments conducted by ARCO Technology and Exxon Production Research (Salathiel, 1973) it was demonstrated that the original residual oil saturation in oil wet and mixed-wettability rocks could be reduced with continuous flushing with water. This is likely the result of the component segregation within the oil film leaving the lighter lower viscosity components near the top of the oil film in contact with the water moving through the center of the pore network. Vance, et al.

(2011) have identified several fairways through southeast New Mexico where meteoric water from outcrops of the San Andres formation flow eastward into the Permian Basin of West Texas. Their modeling has indicated that on the order of 20 pore volumes of water have passed through the San Andres formation through geologic time. Based on the modeling results reported by Salathiel, the trapped oil saturation may have been reduced by approximately 35 percent yielding an expected trapped oil saturation range of 20 to 26 percent in the fairways that have experienced 20 pore volumes of flushing. A trend of gradually increasing residual oil saturations would be expected from Southeast New Mexico to West Texas as the result of water flow through the fairways.

63. The residual oil in the intervals swept by meteoric water would likely be composed of the heavier hydrocarbon components and would have a lower API gravity than the oil accumulated in a structural trap. As a result of the increased concentration of heavier hydrocarbon components, the viscosity of the oil in the intervals containing residual oil would be expected to be higher. A trend of decreasing viscosity would be expected from Southeast New Mexico toward West Texas.

Expected Wettability in the Hydrocarbon Trap and Residual Oil Zone

64. Prior to oil emplacement, the reservoir would be water wet. The same physics applies as in the migration paths. As long as the oil is moving, the carbonate formation remains water wet. When the oil becomes static, the wettability alteration mechanism discussed above takes place and the main accumulation and transition zone become oil wet.

65. In the ROZ scenario proposed by Trentham and Melzer, the original (paleo) oil water contact is translated upward as the result of structural displacement resulting from faulting, a trap breach, or by changing hydrodynamic conditions below the main accumulation. Oil is displaced and a shallower oil-water contact is established. In this situation, residual oil saturations

equal to or higher than those expected for the migration pathways would be expected. The residual oil saturation would depend on the volume of water influx into the region between the paleo water-oil contact and the "new", shallower oil-water contact. Core data from the ROZ interval existing at the SSAU (Honarpour et al. 2010) indicated residual oil saturations ranging from roughly 18 to 45 percent in the interval between the paleo and present-day oil-water contact. Higher residual oil saturations could exist in intervals where water influx was limited.

66. The reported oil gravity above the oil water contact at the Maljamar field is 38 Deg. API. The reported oil gravity above the oil-water contact at the EMSU is 32 Deg. API.

67. Based on the proportionality of the above versus below the oil-water contact API gravities observed at the SSAU, the API gravity below the oil-water contact at EMSU would be expected to be about 27 Deg. API.

<u>Correction of Core Saturations</u>

68. **Research conducted by ARCO Technology has shown that bleeding during core retrieval is proportional to the gas content and viscosity of the oil. By using the API gravity and viscosity data reported by Hess and the API gravity and bleed factor from the Maljamar pressure core, it was possible to estimate the bleed fraction for the oil present in the core from EMSU 679. Standard petroleum fluid property correlations were used to convert the Maljamar bleed fraction to the conditions existing in the EMSU at the time EMSU 679 was cored. Calculations were performed for the range of pre-waterflood reservoir pressures supported by available pressure test data (roughly 350 psi to 1300 psi). The bleeding fraction for the EMSU 679 core was found to range from 3.47 percent to 9.03 percent. Calculations were also performed to estimate the formation volume factor of the oil in the EMSU 679 core and the fraction of pore volume reduction that would occur between**

lab stress conditions and reservoir stress conditions. From these calculations, it was possible to compute an overall correction factor to correct the raw oil saturation measurements from the EMSU 679 core to reservoir conditions. A range of oil saturation correction factors from 1.095 to 1.250 was obtained. The value derived from the ARCO "Rule of Thumb" method that I used for the original calculations reported in my direct testimony was 1.22. The rigorous analysis has shown that the corrections performed during my original petrophysical modeling were reasonable.

69. During my deposition on Nov. 22 of 2024, Empire's counsel asked several questions concerning the uncertainty of the core saturation measurements from EMSU 679 and the procedures used to correct the core oil saturation measurements. I used a "rule of thumb" method developed by ARCO Technology designed to estimate residual oil saturations in waterflooded intervals from routine core saturation measurements for wells drilled with water-base muds. The procedure is based on research conducted by Jake Rathmell of ARCO Technology and was later partially documented by Rathmell et al. (1973).

70. The corrections involve the use of the formation volume factor, Bo for the reservoir oil for the condition reflecting the lowest reservoir pressure experienced in the reservoir, an assumption of a loss of 10 percent of the oil by gas expansion during core retrieval and an assumption of a 5 percent reduction in pore volume resulting from increased stress at reservoir conditions compared to lab conditions.

71. A formation factor, Bo of 1.05 reservoir barrels per stock tank barrel was reported for the EMSU in a technical committee report published in April 1983 prior to the initiation of waterflood operations. Using this value for Bo, with a 10 percent oil bleed and 5 percent pore

volume reduction, an overall oil saturation correction factor of 1.22 is obtained. This factor was used to correct the EMSU 679 oil saturation measurements to reservoir conditions.

72. In my petrophysical model, the fluid saturations are calibrated to best match corrected core oil saturations.

73. Data from the pressure core analysis data recorded for well 358 from the Maljamar field were used to check the validity of the correction factor used in NSAI's original petrophysical modeling. The gravity of the oil below the oil-water contact for the EMSU was estimated to be 27.0 Deg. API. The reported oil gravity for the Maljamar field above the oil-water contact was 38 Deg. API. This indicates that the gas content and viscosity of the oil below the oil-water contact in the EMSU would be much lower than at Maljamar. Rathmell et. al. (1973) demonstrated that oil expulsion (bleeding) resulting from gas expansion was proportional to the dissolved gas content in the oil at the time coring occurred.

74. The Bo recorded in the DOE study for Maljamar (1.19 reservoir barrel per stock tank barrel) and the oil bleed fraction of 19.2 percent (discussed above) were corrected to the conditions existing below the oil-water contact at the EMSU using standard oil property correlations presented by McCain (1973). The corrections utilize API gravity, reservoir temperature, and reservoir pressure. The reservoir temperature at the EMSU was assumed to be about 94 Deg. F. A range of available reservoir pressure measurements prior to the waterflood were considered in the Bo and bleed factor analysis.

75. Based on the fluid property correlations, the Bo values for the San Andres interval below the oil-water contact at the EMSU would range from 1.05 RB/STB to 1.13 RB/STB.

76. Correcting the bleed fraction of 19.2 percent observed at Maljamar to the dissolved gas conditions predicted to be present at the EMSU, a range of bleed fractions from 3.47 percent to 9.03 percent was obtained.

77. An assumed 5 percent pore volume reduction resulting from differences in lab stress (300 to 800 psi) to a net reservoir stress (about 1400 psi in this case) was based on the assumption the reservoir was composed of clastic (quartz-dominated) sediments. Carbonate reservoirs typically have much lower compressibilities than clastic reservoirs, particularly when dolomitization has occurred. A carbonate compressibility correlation developed by Shell Production Research (van der Knapp, 1959) was used to estimate the pore volume compressibility for stress conditions corresponding to the range of reservoir pressures. A compressibility range of 4.1 to 5.0 microsips was estimated. A model developed by Marathon Oil Company (Jones, 1988) was used to predict the pore volume reduction corresponding to the calculated compressibility values. A range of pore volume reductions of 0.7 percent to 0.6 percent was obtained for the reservoir pressure condition. In both cases the predicted pore volume reduction was less than the 5 percent pore volume assumed with the "rule of thumb" estimates.

78. Combining the Bo, bleed fraction, and pore volume reduction estimates into an overall core oil saturation correction factor estimate, a range from 1.095 to 1.250 was obtained. The ARCO "rule of thumb" method yielded a correction factor estimate of 1.22. Based on this analysis, I am confident that the corrections applied to the core oil saturations for EMSU 679 for my original petrophysical modeling were reasonable.

Water Expulsion

79. **Of the 17 pressure cores cut in Maljamar 358, 3 lost pressure during coring operations. For all practical purposes these 3 cores became conventional cores. At surface,**

the average percentage of liquid (oil plus water) was 61 percent for the non-pressured cores. The oil saturations from the non-pressured cores were corrected for bleeding and shrinkage and then the fraction of water expelled from the cores was computed assuming that the cores were 100 percent liquid-filled in the reservoir. This is a reasonable assumption considering the fact that the purpose of the coring job was to determine the residual oil saturation following long-term waterflooding. It was found that about 49 percent of the water originally in the cores had been expelled as the result of gas expansion. In the core from EMSU 679, the average fraction of liquid fill was about 66 percent. After correcting the raw core oil saturations for bleeding and shrinkage, it was estimated that roughly 35 to 65 percent of the water originally in the cores was expelled through the cored interval.

80. **The revised NuTech petrophysical model was calibrated to the raw water saturation measurements from the cores. As a result, the model predicts water saturations that are too low and oil saturations that are too high.**

81. Three of the 17 pressure cores cut in Maljamar 358 lost pressure sometime during coring operations. Comparisons were made to the core oil saturation from the pressured and non-pressured cores, and it was observed that there was no significant difference between the residual oil saturation values. This indicates that little or no oil was lost due to pressure differential at the bit in the non-pressured cores. Using the formation volume factor and bleed fraction estimate discussed above, it is possible to make corrections to the oil saturation measurements from the cores that lost pressure.

82. On average, the total fluid content (oil and water) of the non-pressured cores was only 61 percent of the total pore volume. By correcting the oil saturations using the formation volume factor and average bleed fraction, it is possible to roughly quantify the amount of water

that was expelled from the non-pressured cores during core retrieval. As mentioned above, the average bleed fraction for the oil was 19.2 percent. It was found that roughly 49 percent of the water originally present in the core was expelled during core retrieval as the result of dissolved gas expansion. In other words, substantially more water was expelled than oil. This is not surprising in an oil wet reservoir near residual oil saturation conditions. Oil is in contact with the carbonate rock surfaces and the heavier polar hydrocarbon components are bound to the rock surfaces by van der Waals surface forces. At residual or near residual oil saturation conditions, some fraction of the lighter hydrocarbon components have been displaced during waterflood operations. This increases the viscosity of the oil remaining in the film coating the rock surfaces. The water largely resides in the central portions of the pore network and moves much easier than the oil. For example, for a well producing at a 95 percent water cut, the water is 19 times more mobile than oil. Even at the most pressure-depleted condition, the surface volume of the dissolved gas is roughly 5 times the volume of the pores. As the gas expands, liquids are expelled in a non-pressured core.

83. The cores cut in EMSU 679 were not pressure cores. The average fluid content (oil plus water) of the cores at surface conditions was 65.9 percent. The corrections to the oil volumes only increases the percent filled to 69.5 percent. As with the core from Maljamar 358, the core from EMSU 679 would be expected to be fully liquid saturated at reservoir conditions. The cored interval was roughly 175 feet below the oil-water contact. After correcting the core oil saturations for bleeding and shrinkage, calculations were performed to estimate the fraction of water expelled from the EMSU 679 core. It was estimated that 35 to 65 percent of the water originally in the core at reservoir conditions was expelled during core retrieval. Water was obviously expelled during core retrieval.

84. It is therefore not surprising that all of the NuTech interpretations overestimate the oil saturations in EMSU 679, SSAU 4113R, and Maljamar 358 (see Figures 10 and 17 from my written testimony and Figure 7 from this document). The first two NuTech models were not calibrated to core data at all and did not account for variations of rock types that are known to exist in the San Andres. The final NuTech model was calibrated to the raw, uncorrected core water saturation measurements from EMSU 679 that have been shown to be too low due to water expulsion during the coring process. This would result in the overestimation of the oil saturation as So is 1 – Sw. In summary, none of the NuTech models can be relied upon to provide accurate estimates of oil in the intervals below the oil water contact in the EMSU.

<u>**Mobile Oil Observed in the Cored Interval in Maljamar 358**</u>

85. **Based on the core oil saturation measurements from Masljamar 358 and the available well test data, it appears that oil becomes mobile in the San Andres at slightly above trace levels when the oil saturation exceeds about 32 percent. Examples are given for EMSU 660 and EMSU 746 where both the revised and original NuTech models would predict the presence of significant volumes of mobile oil in intervals that produced 100 percent water from the San Andres during well tests. The NSAI model did a much better job of predicting where oil would and would not flow. It can be shown that the calibration of the revised NuTech model to the uncorrected core water saturations in EMSU 679 leads to overly optimistic estimates of oil saturations in both the Grayburg and San Andres formations.**

86. Based on the test data from Maljamar 358 and the available core data, it appears that oil would become mobilized at in situ conditions at an oil saturation of roughly 32%.

87. Figure 8 shows interpreted water saturations for EMSU 660. Displayed are the NSAI solution, the original NuTech solution (NuTech2) and the revised NuTech solution

(NuTech/Empire). Test intervals are shown with flags in the depth track. The lowest test interval (San Andres 4126 to 4239 ft.) produced 3 barrels of oil and 1057 barrels of water in 24 hours on an ESP test from Mr. West's written testimony (99.7 percent water cut). NSAI's solution contains a small interval that would likely produce a small quantity of mobile oil in line with the observed water cut. Unfortunately, long term test data are not available for this interval as the well was plugged back to work on perforations in the Grayburg. Both of Nutech's models would predict sustained mobile oil production and this interval would likely have not been abandoned if the operator believed sustained oil production was possible.

88. The Grayburg was tested in an interval from 3784 to 3912 ft. and produced 11 barrels of oil and 158 barrels of water in 24 hours (93.5 percent water cut). Both the original NuTech and revised NuTech models predict oil saturations as high as 82 percent in this interval. These high oil saturations are incompatible with the observed water cut of 93.5 percent. The NSAI oil saturations of 30 – 50 percent for this interval are much more realistic given the high water cut.

89. In EMSU-746 the San Andres formation was tested in its lower and upper sections individually and each produced 100% water. These perforations are displayed as blue flags on the interpreted log image given at the end of this document. The final producing perforations (in green) in the Grayburg formation produced at 96% water cut. Bridge plugs are also noted as large gray flags in the depth tracks. Both NuTech's original and revised interpretations indicates the presence of mobile oil (So > 32%) in both of the San Andres perforated intervals that produced 100% water. Their interpretations are also not consistent with the water cut in the producing interval.

90. A comparison between the NSAI model and the revised NuTech model (NuTech/Empire) is provided for the cored well, EMSU679, on an interpreted log image provided at the end of this document. A comparison of the log-derived porosity from the NSAI model and

the revised NuTech model is shown in Track 8 along with the core measurements (pink dots). The two models agree well with each other and with the core porosity measurements. Track 9 shows the water saturation values predicted by NSAI's model (NS_Sw_Final). Also posted are the corrected core oil saturations (green dots posted on a reversed scale) and the uncorrected core water saturations (blue dots). The oil saturations were corrected for bleeding and shrinkage. It has been shown that in a conventional core, water is expelled from the core as the result of dissolved gas expansion during retrieval from the well, therefore the uncorrected core water saturations are too low. The core in EMSU 679 was cut below the oil-water contact in an interval containing residual oil. The residual oil would be immobile while the core is being cut and oil would be lost to bleeding and shrinkage resulting from dissolved gas expansion as the core was retrieved from the well. The interval would have been liquid-filled in the reservoir therefore, the true water saturation would be 1.0 minus the corrected oil saturation. The log-derived water saturation estimates should pass through the green dots. The separation between the blue dots and the green dots is indicative of the level of water expulsion resulting from dissolved gas expansion. In general, between 35 and 65 percent of the water appears to have been expelled from the cores cut through the Grayburg-San Andres interval with the highest water expulsion occurring in the upper portion of the cored interval.

91. Track 10 shows the water saturation estimated with the revised NuTech model (NuTech/Empire). As described in Mr. Dillewyn's verbal deposition, the m and n values were adjusted through the cored interval to bring the well-log-derived water saturations into agreement with the core water saturation measurements. Notice that the log-derived water saturations do a reasonably good job of matching the uncorrected water saturations through the Grayburg-San Andres interval. The problem is that the core water saturations do not represent reservoir

conditions. They are too low. The water saturation model should have been calibrated using corrected core oil saturation measurements (Sw = 1.0 – corrected So). The revised NuTech model consistently overestimates the amount of oil present.

92. The green bar, extending from roughly 3850 to 4100 ft. (between Track 2 and 3), represents an interval that was tested in the Grayburg. Test data from Maljamar 358 showed that oil became mobile at oil saturations exceeding 32 percent. Note that the NSAI model predicts that several intervals within the green test interval have oil saturations exceeding 32 percent and would be expected to produce some oil. The test interval produced at a water cut exceeding 94 percent. The revised NuTech model predicted oil saturations that were in the 60 to 80 percent range through the tested interval. At these high oil saturations, the 94 percent water cut does not seem feasible. A much lower water cut would have been expected. The oil saturations predicted with the NSAI model are more in line with observed well performance.

93. It appears Empire was correct in abandoning the original petrophysical modeling results computed with NuTech's simplistic model with constant m and n values. The original NuTech models (NuTech1 and NuTech2) consistently predict the presence of mobile oil in the San Andres intervals that tested 100 percent water flow. It is clear that the NuTech petrophysicist did not review the well performance data. The electrical parameters m and n were varied in the revised NuTech model (Nutech/Empire) to improve the agreement with the core water saturation measurements. This basically proves the point made in my original direct written testimony (Aug. 16, 2024). Simple classical petrophysical models are unable to accurately model the complex behavior of the carbonate rock types present in the Grayburg and San Andres formations. The revised NuTech model was a step in the right direction, but the model was calibrated to water

saturation measurements from EMSU 679 that were too low because they did not account for water expulsion that would have occurred during core retrieval.

94. Empire's revised model likely significantly overestimates the oil saturations in the San Andres formation. Empire's oil-in-place estimates include intervals containing oil saturations below 20 percent where the oil will not be likely mobilized with miscible CO_2 injection as well as intervals in the deeper facies of the San Andres carbonate ramp that likely consist of immobile solid organic matter.

Interpreted Potential Vertical Flow Barriers

95. **Log analysis was used to identify the location of potential flow barriers that would prevent vertical flow between the water disposal interval currently being utilized by Goodnight and the Grayburg formation where Empire is conducting waterflood operations. Potential impermeable barriers were interpreted to be present in intervals containing significant volume of anhydrite and in intervals consisting of deep-water lime muds. Petrophysical modeling indicated the potential presence of karsts and related collapse breccias in both the Grayburg and San Andres formations. I was provided with a set of tops where circulation was lost in four of the salt-water disposal wells operated by Goodnight. It was found that circulation was lost beneath intervals interpreted to be anhydrite barriers. These barriers were found to be 90 feet or deeper below the top of the San Andres. Intervals interpreted as being karsts were found to be located below the loss circulation tops. The fact that drilling operations could be conducted through the Grayburg with no loss circulation events is evidence that the Grayburg is isolated from the water disposal interval employed by Goodnight. The Goodnight wells operate on a vacuum and inject very large volumes of water on a daily basis. Unless Empire is producing significantly more water than**

is being injected in its waterflood operations, it is difficult to imagine a scenario where water entering the San Andres disposal zone under a vacuum could move upwards into the overlying Grayburg formation.

96. **Based on the location of the loss circulation tops, it appears that the upper portion of the San Andres is likely pressure-isolated from the lower San Andres interval where water disposal operations are occurring.**

97. I was asked by Goodnight to identify potential barriers to vertical flow as a part of my petrophysical evaluation. From a rock-type perspective, low-porosity limestone intervals and intervals containing anhydrite would be considered potential vertical flow barriers. Based on a review for the available core measurements, dolomitized intervals with porosities less than 7 percent might also be flow barriers as a result of their low vertical permeability. As detailed in my written testimony, flags identifying potential vertical flow barriers were included with the log interpretation results provided. I requested surface injection pressure data and disposal rate data from Goodnight for the purposes of validating the permeabilities derived from my model. I was informed that loss circulation issues were routinely encountered during the drilling operations and that the disposal wells generally injected on a vacuum. I requested the loss circulation tops and began looking for evidence of karsting because the rock permeability values computed from the well log measurements were not high enough to support injection on a vacuum. The presence of karsts would not be unusual given Trentham's description of multiple pore volumes of meteoric water passing through the San Andres ("Mother Nature's Waterflood"). The loss circulation tops were posted on the disposal well interpretations. Loss circulation was generally found to occur below the base of thick anhydrite-bearing intervals. Potential karst intervals were identified on the interpreted well logs. An example disposal well interpretation is shown on the log image for YAZ

28 SWD 1 at the end of this document. The log interpretations for the Goodnight disposal wells were not provided with my original direct written testimony because the Commission had limited the scope of the hearing to wells within the EMSU. During my deposition Empire's counsel requested all the disposal well interpretations I had prepared because they had been an important part of my petrophysical model development. Digital and pdf versions of the log interpretations for the 4 disposal wells that I interpreted were provided to Empire shortly after the deposition.

98. Returning to the log image for YAZ, the loss circulation top is posted in the depth track at about 4325 ft. The well was drilled through the Grayburg formation and the uppermost section of the San Andres formation maintaining a mud column in the wellbore. The interpreted lithology track (4) shows that circulation was lost beneath an anhydrite-bearing dolomite existing from around 4185 to 4230 ft. Flags identifying potentially karsted interval are shown in the resistivity track (2). This suggests that the deeper part of the San Andres formation, where disposal operations are occurring, exists at a much lower formation pressure than the Grayburg and uppermost San Andres. As far as I know, water injection at the EMSU is not on a vacuum.

99. Loss circulation tops were found to be 90 feet or more below the top of the San Andres in the three Goodnight disposal wells south of the EMSU.

100. The Ryno (Snyder) disposal well is located within the EMSU. The loss circulation top in that well is also about 90 feet below the top of the San Andres. This well experienced long-term loss circulation issues during drilling operations. Possible karsts were identified in the Grayburg above the loss circulation zone. Collapse breccias associated with failed karsted intervals have been documented within the Grayburg by Empire in earlier written testimonies. The fact that a mud column could be maintained while drilling through the Grayburg prior to

encountering loss circulation in the San Andres indicates that a pressure differential likely exists between the San Andres disposal zone and the overlying Grayburg.

101. The evidence supports concluding that the upper part of the San Andres, above the loss circulation tops, may be in pressure isolation from the San Andres disposal zone below.

102. Anhydrite zones have been interpreted at various locations in the Grayburg and San Andres in all the wells that I have evaluated in and around the EMSU. These anhydrite intervals likely act as both vertical and areal flow barriers. Early in my career with ARCO Oil and Gas Company, I was assigned as the petroleum engineer for the J. L. Johnson AB Lease in Ector County, Texas. The J. L. Johnson Lease is located on the eastern edge of the Central Basin Platform and like the EMSU, consists of a Grayburg oil reservoir sitting atop a San Andres aquifer. When I joined ARCO, the lease was undergoing an infill drilling program to improve waterflood performance. The field was being down-spaced from 40-acre spacing to 10-acre spacing. Infill drilling was undertaken as the result of poor waterflood performance. Log and core analysis had shown that areal and vertical barriers within the dolomite reservoir in the Grayburg were adversely impacting the areal and vertical sweep of the injected water. The barriers were found to be associated with anhydrite-bearing intervals within the dolomite formation and with dissolution-reprecipitation reactions resulting from interactions between anhydrite and the injected water. Infill drilling to 10-acre spacing did not completely solve the sweep efficiency problem. It was necessary to hydraulically fracture the wells to establish effective communication between the injection wells and the producing wells. Great care was taken in the design and implementation of the frac jobs to ensure that the fractures did not penetrate the San Andres aquifer which existed below the Grayburg. The improved field performance resulting from the down-spacing and

hydraulic fracturing program was documented in an SPE paper prepared by Richard Prentice (1984).

103. During the early 1980s, ARCO was evaluating many of its West Texas waterfloods for potential CO_2 enhanced recovery operations. As a part of the evaluation program, cores were cut to gather petrophysical data. I was involved with a coring program underway at the J. L. Johnson Lease at that time. It is not always easy to pick the correct depth to initiate coring operation when a well is being drilled. On one of the coring jobs that I was involved with, we started coring too late and only the bottom part of the Grayburg was captured. The core penetrated down into the San Andres Aquifer. It was observed that at least in this part of the field, a thick anhydrite layer acted as the barrier between the San Andres aquifer and the Grayburg oil reservoir.

Core Data from NMGSAU Well 522

104. **Empire has introduced a core analysis report from North Monument Grayburg San Andres Unit 522 as evidence that high residual oil saturations and an ROZ interval exist in the San Andres formation below the oil-water contact in that field. I have been unable to locate conventional open-hole log measurements (gamma ray, resistivity, bulk density, neutron, sonic) for that well in public databases. Measurements from an electromagnetic propagation tool (EPT) were available. The core analysis company (TerraTek) noted in the core analysis report that the oil saturations from this well seemed anomalous compared to the core measurements from another well cored near the oil-water contact in the same field. Data from OCD files indicate that oil was added to the drilling mud just before coring operations began in this well. In a subsequent well test conducted in the San Andres, an interval with indicated high oil saturations was perforated and immediately abandoned even though the reported saturations on the core report indicated**

the presence of oil at saturations capable of flow. An interpretation of EPT indicates that the water saturation near the wellbore (in the interval with elevated oil saturations) increased following coring indicating the possibility that oil from the drilling mud had entered the formation and was dissipating away from the borehole. It is difficult to come to firm conclusions regarding the core oil saturations without access to a more complete open-hole log dataset as well as the drilling and mud records.

105. During my deposition, Empire's counsel asked questions concerning core oil and water saturation measurements that had been reported for NMGSAU 522. I did not receive that data and the service company report until August of 2024 and did not have time to fully evaluate it as I was trying to complete my direct written testimony for the then scheduled September 2024 hearing. At that time, I was under the impression that data from outside the confines of the EMSU were not admissible for the purposes of the upcoming hearing. I had not had the opportunity to fully search for all of the available records concerning that well and could not locate the open-hole well logs on public data sites. I was not comfortable commenting on the data until I had time to evaluate all of the available data concerning that well.

106. Since that time, I have been unable to locate any publicly available conventional open-hole well log measurements (gamma ray, resistivity, neutron, bulk density, sonic) for the NMGSAU 522. I was able to obtain raster images of measurements from an electromagnetic propagation tool (EPT) run in that well after coring operations had been completed. I was also able to locate some records concerning the cementing operations and well testing in records available from the OCD.

107. In short, it is Empire's contention that the core data from NMGSAU 522 shows evidence of an ROZ below the oil water contact in the North Monument Grayburg-San Andres Unit containing oil saturations of up to 60 percent.

108. The following events were recorded on completion records available from the OCD (see Figure 9). The well was drilled to a depth of 410 ft. and surface casing was cemented on July 29, 1992. The well was drilled to a depth of 3673 ft. and an intermediate casing string was cemented on August 10, 1992. Drilling and coring operations occurred between August 10,1992 and August 26,1992 when the production casing was cemented in the well to a depth of 4550 ft. The core interval was from 3775 ft. to 4399 ft. which is within the interval drilled between Aug. 10 to Aug. 26.

109. A letter was present in the OCD files dated August 12, 1992 (Figure 10) stating that 50 barrels of lease crude had been added to the drilling mud on Aug. 8, 1992 for drilling operations and would not be recovered. This was just before the coring operations would have begun. It is unlikely that the drilling mud would have been changed out just prior to coring which would have begun sometime after Aug. 10. I was unable to obtain drilling records for this well to confirm that the oil was in the mud during coring operations.

110. An electromagnetic propagation tool (EPT) was run in the well just prior to cementing operations on Aug. 26, 1994. An EPT is a tool designed to measure the volume of water in the near-wellbore region. The core oil and water saturations are shown in Figure 11 along with the digitized raw EPT measurements. Note how the oil saturations in the lower portion of the well within the San Andres formation are higher than the saturations in the Grayburg. Given that the highest oil saturations are in the San Andres interval below the oil-water contact that had been

established for the Grayburg, it is Empire's contention that this proves that there is an ROZ in the San Andres.

111. TerraTek, the core analysis service company, pointed out that the oil saturations in the San Andres interval had a different trend compared to the core recovered from the San Andres in another NMGSAU well. "Oil saturation follows a somewhat different trend in the cored portion of the San Andres in this well compared to the NMGSAU #1419 Well. In that well, the oil saturation gradual diminished to zero. In this well, the saturation remains high throughout the San Andres." (see referenced TerraTek core analysis report). I do not have access to the core data from NMGSAU 1419, but comparisons can be made to average oil saturations below the oil-water contact in Maljamar 358 and EMSU 679. The average oil saturation in the San Andres interval below the oil water contact in Maljamar 358 was 17.1 percent. The average corrected oil saturation below the oil-water contact in EMSU 679 was 18.2 percent. The average oil saturation below the oil water contact (corrected for shrinkage and bleeding) in NMGSAU 522 was 40.0 percent.

112. NMGSAU 522 was cored using conventional (non-pressured) core barrels. Therefore, fluid expulsion occurred during core retrieval. When a non-pressured core is cut through an interval containing mobile oil, oil is displaced from the core by mud filtrate invasion. When water-base drilling muds are used, the usual result is that some portion of the oil is displaced by the mud filtrate and the resulting oil saturation in the core is too low compared to reservoir conditions. During core retrieval, gas is expelled from the oil as the result of decreasing pressure resulting in shrinkage of the oil, bleeding of the oil due to gas expansion and expulsion of some of the water and drilling mud filtrate that was present in the core.

113. Below the oil-water contact, a slightly different situation exists. In intervals below the oil water contact, any oil present would be expected to be at residual conditions. It would

therefore be expected to be immobile. When a conventional (non-pressured) core is drilled through an interval containing residual oil, the mud filtrate does not displace the oil out of the core. Some of the original formation water is displaced by the mud filtrate. During retrieval, gas is expelled from the oil causing shrinkage and bleeding and some of the water in the core is expelled due to gas expansion. This situation would have occurred when the core from EMSU 679 was drilled. Corrections to the raw oil saturation measurements were only needed for bleeding and shrinkage.

114. A different situation exists when an oil phase is present in the drilling mud. Lease crude was added to the drilling mud prior to coring operations, assuming that the mud system was not changed out just prior to coring, the drilling mud would have been composed of water, oil, and mud-solids. The San Andres crude typically has a relatively high asphaltine content (Ramondetta, 1982). Asphaltines are polar molecules with positive and negative ends associated with the molecular chain. Because the San Andres is oil-wet, oil in the interval below the oil water contact would reside on the carbonate grain surfaces and the water would reside in the middle of the pore network. During coring, a pressure differential would exist between the drilling mud and the interior of the core. A process known as spontaneous imbibition would occur. With spontaneous imbibition, the saturation of the wetting phase (oil in this case) is increased when the pressure is increased in the presence of the wetting phase (oil) in the displacing fluid. The polar molecules in the oil in the mud are attracted to the carbonate surface by van der Waals forces. The oil saturation is increased. The invading oil would be "dead". Because it was lease crude, most of the gas originally present in the oil would have escaped at surface temperature and pressure. During core retrieval, less of the oil present in the core would have been lost because it was likely a mixture of live reservoir oil and dead lease crude. This scenario could explain the higher-than-expected oil saturations present below the oil water contact in the NMGSAU 522 core.

115. Below the oil water contact, spontaneous imbibition would have temporarily increased the oil saturation near the borehole. With time, the oil would be drawn further into the formation by spontaneous imbibition and the water saturation near the wellbore would increase. Above the contact, mobile oil was displaced away from the wellbore due to mud filtrate invasion. With time, oil would migrate back toward the wellbore and the oil saturation would increase.

116. The EPT was run in the well after drilling and coring was complete, just before the production casing was run and was cemented. The raw EPT measurements were interpreted to provide estimates of the water volume in the near-wellbore region using a standard model (see for example Asquith 1996). The model provides water volume estimates in terms of cubic centimeters of water per cubic centimeter of rock. The core oil saturation measurements from the cores were corrected for bleeding and shrinkage using the correction factors developed for the EMSU (discussed above). Water was expelled from the core as it was retrieved. A reasonable estimate of the water saturation present in the core at reservoir conditions can be made by simply subtracting the corrected oil saturation from 1.0. The volume of water in the core at reservoir conditions was estimated by multiplying the corrected reservoir water saturation estimates by the measured porosities from the core.

117. The core-derived water volume estimates along with the water volume estimates from the EPT at each core point are displayed in the far right-hand track in Figure 11. Above the oil water contact, the water volume estimates from the EPT are lower than the estimates from the corrected core data. This indicates that oil was migrating back toward the wellbore following coring operations and that mobile oil was present in the Grayburg interval above the contact. This was confirmed by a production test carried out by Hess for the interval from 3870 to 3889 ft. The well produced 190 barrels of oil and 170 barrels of water during a 24-hour test (see Figure 12).

118. Below the oil water contact, the water volume estimates from the EPT are higher than the estimates from the corrected core data. This indicates that oil was migrating away from the wellbore following coring operations. This would occur as the result of the spontaneous imbibition process drawing the local increased volume of oil near the wellbore into the formation. It is interesting to note that the records indicate that Hess made no effort to test the San Andres interval below the oil water contact in this well. The highest core oil saturations were below the oil water contact. Testing of the San Andres at Maljamar 358 showed that oil in the San Andres would become mobile at higher than trace levels when the core oil saturations exceed about 32 percent. The oil saturations in the San Andres interval in NMGSAU 522 reach levels above 60 percent. It could be that Hess had access to open-hole resistivity measurements that showed that the San Andres was likely wet.

119. The NMGSAU was sold to Apache. Apache prepared a recompletion program for this well (see Figures 13 and 14). Several intervals in the San Andres were perforated as shown in Figure 15. No oil or water volumes were reported but these perforations were immediately abandoned beneath a bridge plug and tests shallower in the Grayburg were undertaken. The most likely conclusion that can be drawn is that the San Andres perforations did not produce oil despite the high oil saturations indicated with the core measurements.

120. A more complete interpretation of the oil saturation data from the NMGSAU 522 core data could be made if open-hole gamma ray, resistivity, neutron, and bulk porosity measurements were available. Based on the available data, the scenario discussed above seems reasonable. Given the likelihood that oil was present in the drilling mud at the time coring operations were underway, the oil saturation measurements from the core do not appear to be representative of reservoir conditions.

Error on the NGS Exhibit

121. **Figure 3 from my direct testimony had a labeling error. The labels for the raw gamma ray and uranium-corrected gamma ray curves were reversed.**

122. During my deposition I was questioned about Figure 3 in my direct written testimony dated August 16, 2024. I had eye surgery just before the deposition and could not see very well. I tried to explain the meaning of the curves displayed on the figure. It turns out that the raw gamma ray and uranium-corrected gamma ray curves on Figure 3 had been mislabeled. This is shown in Figure 16.

Apparent Continuous Oil Saturation Through the San Andres Formation in EMSU-746

123. **There may have been some confusion concerning the computed water saturation values displayed on the interpreted well log for EMSU 746. Empire's counsel indicated that the log display showed a continuous oil saturation through the entire logged interval. Two water saturation solutions were displayed in the water saturation track, one for NSAI and the other for NuTech. The NuTech solution did indicate the presence of a continuous oil saturation. The NSAI solution did not. I directed Empire's counsel to Figure 14 in my direct testimony which showed that the computed saturation curve from the NSAI model for 746 did not exhibit a continuous oil saturation through the well.**

124. **A revised version of Figure 14 from my direct testimony has been included with this rebuttal document to clarify some of the statements that I made during my verbal deposition concerning the characteristics of an ROZ as defined by Dr. Trentham and what appear to be abandoned paleo oil migration pathways. The intervals with elevated residual oil saturations in the San Andres in EMSU 746, Ryno, and the Goodnight operated salt-water disposal well outside the EMSU (Ted Williams, Yaz and Nolan Ryan) do not fit the**

description of a Trentham ROZ. The intervals of elevated residual oil saturation are thin and widely spaced through the San Andres formation. The thin intervals cannot be correlated from one well to another. A Trentham ROZ is displayed in the interpreted log for SSAU 4113R on the right-hand side of the updated log display. The ROZ consists of a long interval (275 feet in thickness) with oil saturations ranging from 10 to 45 percent and a distinct paleo oil–water contact at 2160 ft. sub-sea. Such an interval is not present in the San Andres in EMSU 746. An interval containing residual oil from waterflood operations is present in the Grayburg formation over the interval from 125 to 525 ft. sub sea.

125. During my deposition, Empire's counsel had several questions concerning my interpretation results for EMSU 746. She noted that there appeared to be a continuous oil saturation through the entire San Andres interval in that well. In the original exhibit for that well two water saturation curves were displayed together in track 7. One of the curves represented the saturation estimates from my model (NS_Sw_FINAL) and the other represented the saturation estimates from NuTech's NuTech2 model (Sw_NUTECH). It is possible that there was some confusion as to which curve represented my model. I referred Empire's counsel to Figure 14 in my direct written testimony and explained that a continuous oil saturation through the San Andres was not predicted. I pointed out how the interval containing volumes of oil with saturations exceeding 20 percent were sparsely scattered through hundreds of feet of San Andres interval. I also noted that many of the intervals with computed water saturation exceeding 80 percent (less than 20 percent oil saturation) were likely composed of bitumen or solid organic matter.

126. Figure 17 is a different version of Figure 14 from my direct written testimony with some additional annotations to help clarify some of my statements. The intervals in the San Andres formation potentially containing residual oil (oil saturation greater than 20 percent) are thin and

spread out over hundreds of feet. The average thickness of the residual oil intervals is less than two feet. It can be seen that 100 or more feet of rock separate the thin intervals containing residual oil. My point in my direct written testimony was that these intervals appear to have the characteristics of abandoned oil migration paths rather than the ROZ accumulations described by Trentham and Melzer. An ROZ fitting the Trentham-Melzer model is shown on the right-hand side of the figure where a relatively continuous interval of San Andres formations from the Seminole San Andres Unit is displayed. At the SSAU, the ROZ interval consistently contains oil saturations exceeding 20 percent over an interval exceeding 275 feet in thickness. Such an interval is present in EMSU 746 in the Grayburg formation, not the San Andres.

127. It is important to note that a saturation profile similar to that found in the San Andres in EMSU 746 was observed in the water disposal wells operated by Goodnight located south of the EMSU. The log image for YAZ shows the results of an interpretation for the Yaz 28 SWD 1 disposal well. The image is included in the back of this document. This well had sonic data available, so it was possible to perform water saturation calculations using both the sonic model and the no sonic model described in my written testimony. Note that the models generally predict the presence of hydrocarbons in the same interval through the San Andres and that nothing close in appearance to a Trentham-Melzer ROZ interval is present. Like the EMSU 746, the San Andres interval in the Yaz disposal well appears to contain sparse accumulations resembling abandoned migration pathways.

Conclusions

128. **The NSAI model was carefully calibrated to the core porosity and corrected core oil saturation measurements from EMSU 679. The model identifies and properly accounts for the petrophysical characteristics of the rock types known to be present in the**

San Andres formation. The model was able to accurately estimate the oil saturations present in the CO_2-swept interval in the main producing zone as well as the oil saturations in the ROZ in the Seminole San Andres Unit well 4113R. The model was also able to produce accurate estimates of the residual oil saturation determined from pressure cores cut in waterflooded interval in Maljamar 358. The model was able to identify intervals containing mobile oil in the San Andres as defined by well testing and long-term production. It was also able to correctly identify intervals where only water was produced.

129. **The initial models supplied by NuTech find mobile oil and ROZ intervals everywhere in the San Andres. They predict the presence of mobile oil in intervals that have been shown through well testing to produce 100 percent water.**

130. **The revised NuTech model provided by Empire in October 2024 does a better job of acknowledging the petrophysical characteristic of the various rock types present in the San Andres. Unfortunately, it was calibrated to the raw water saturation measurements from the core from EMSU 679. The calibration procedure did not take into account water that was expelled from the core during core retrieval and as a result predicts oil saturation that are too high. Examples have been provided showing that the revised NuTech model overestimates oil saturations and predicts the presence of mobile oil where test data indicate the none is present in EMSU 679, EMSU 660 and EMSU 746. Calculation using the parameters from the revised model show that the model would have overestimated the oil saturations measured in the San Andres pressure core from Maljamar 358 as well as known residual oil saturations in the ROZ located under the Seminole San Andres Unit.**

131. **As the result of the overestimation of oil saturations and the failure to use appropriate water saturation cut-offs, the oil-in place estimates provided by Empire are significantly overstated.**

132. I affirm under penalty of perjury under the laws of the State of New Mexico that the foregoing statements are true and correct. I understand that this self-affirmed statement will be used as written testimony in this case. This statement is made on the date next to my signature below.

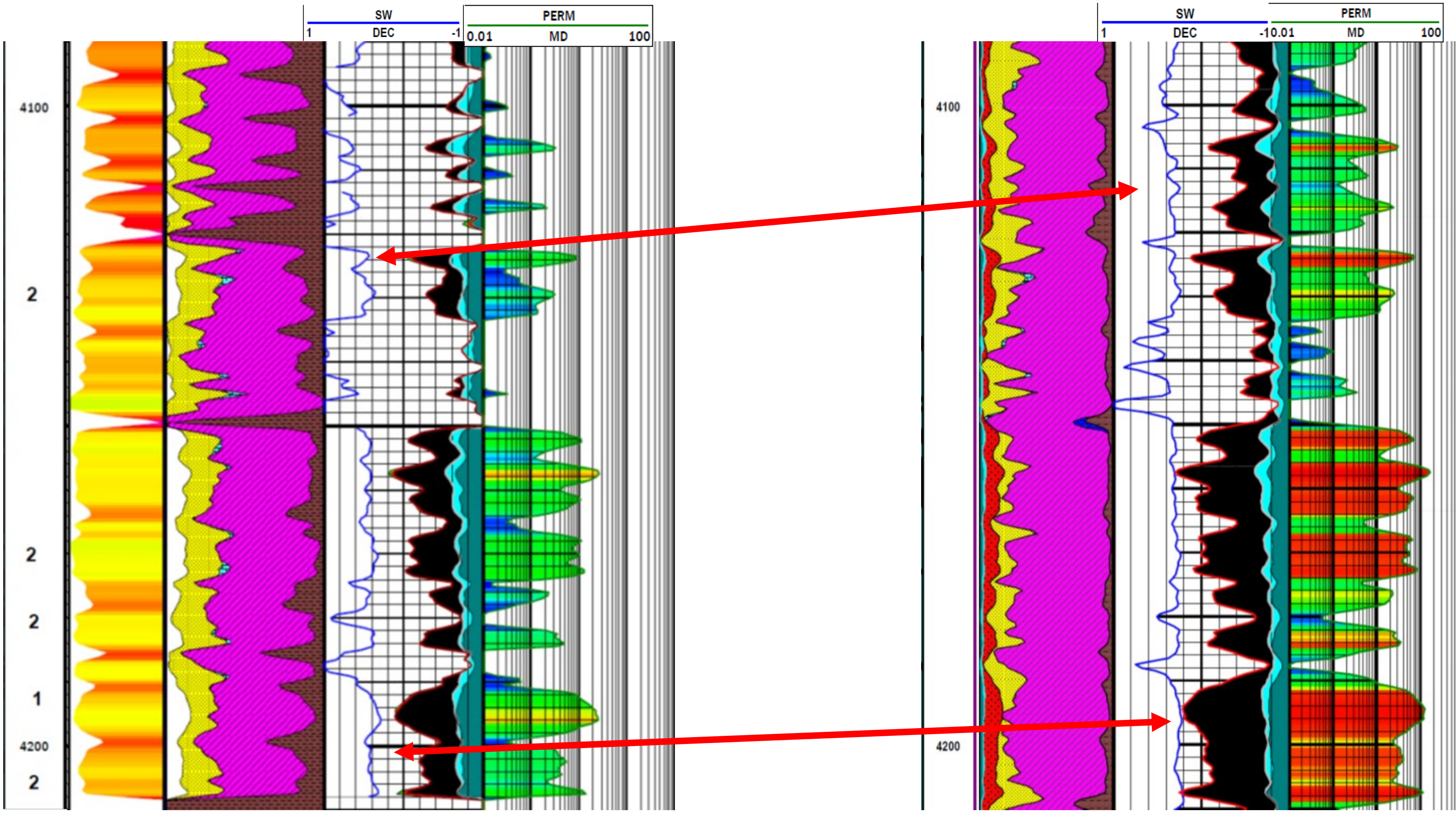
James A. Davidson — February 6, 2025

James A. Davidson Date

NETHERLAND, SEWELL & ASSOCIATES, INC.

NUTECH INTERPRETATION FOR XTO IN EMSU 660

NUTECH INTERPRETATION FOR EMPIRE IN EMSU 660



Notice that much more than just the tops changed between the interpretation for XTO and Empire. A considerable increase in porosity, oil volumes, and perm is noticeable.

Figure 1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

So as you -- as you prepare to appear in front of the Commission in February, what are you going to tell the Commission? Which of these potential analyses is the most likely in terms of oil in place or oil saturation? You can't tell them they're both right. Which one is it? Which is more likely the correct answer?

A. Given the values we have, we stand by our initial interpretation.

Q. How would you do it -- how would you quantify -- like say I pick out say 679, the one we were just looking at, how would I quantify NuTech's uncertainty of this log analysis? Is there a way to quantify it?

A. No, ideally we would have -- one of the parameters of which we use to validate our log interpretation is production as that is a quantity that is generally accurately reported and therefore we can tie back the analysis to.

Page 224

Q. But you didn't do that in any of these wells, did you?

A. No, we did not.

Excerpts taken from Mr. Dillewyn's Deposition Transcript, December 17, 2024, pp. 224-225

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2

NETHERLAND, SEWELL & ASSOCIATES, INC.

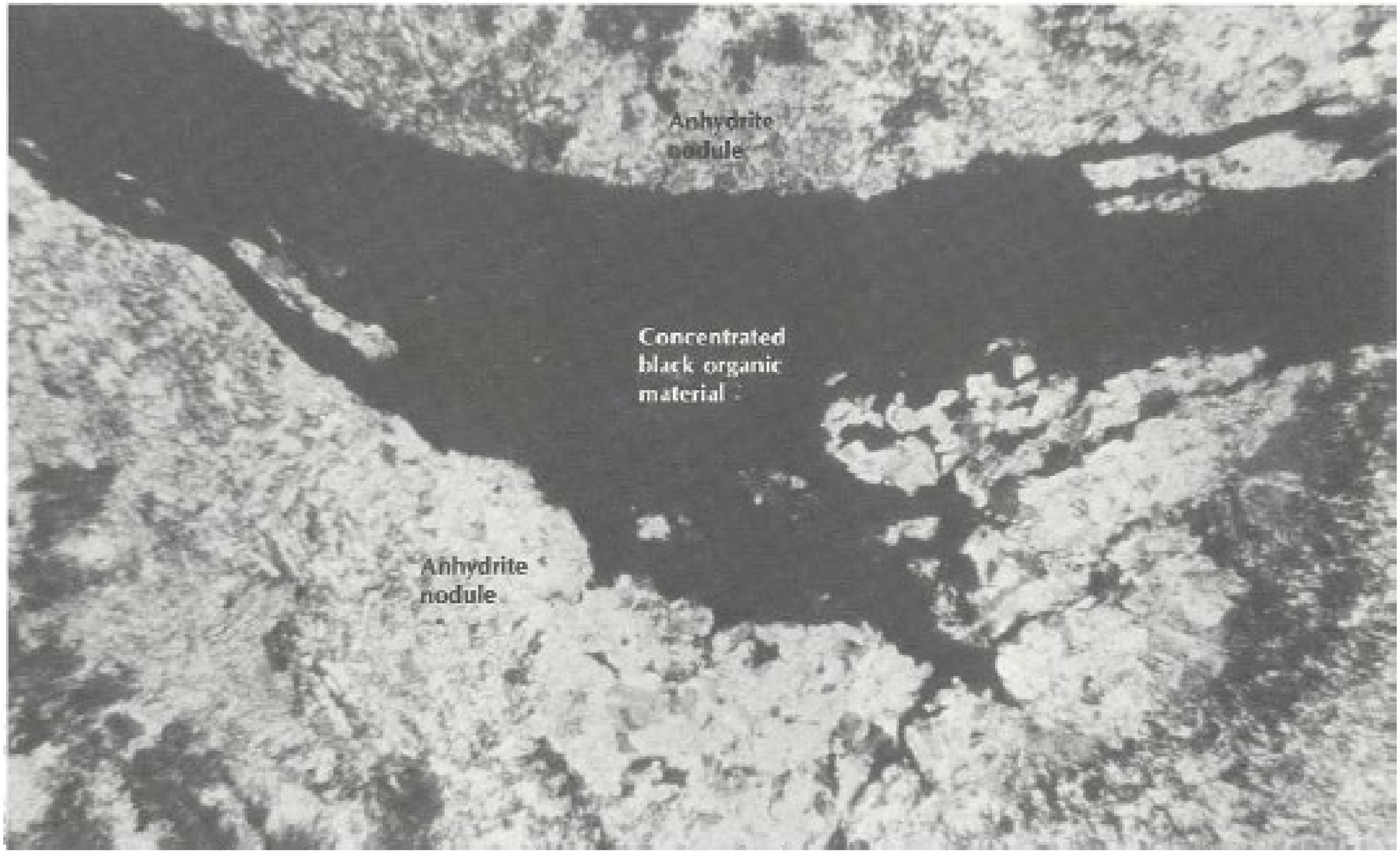


Figure adapted from Figure 13, Ramondetta PJ, 1982, Facies and Stratigraphy of the San Andres Formation, Northern and Northwestern Shelves of the Midland Basin, Texas and New Mexico.

Figure 3

NETHERLAND, SEWELL & ASSOCIATES, INC.

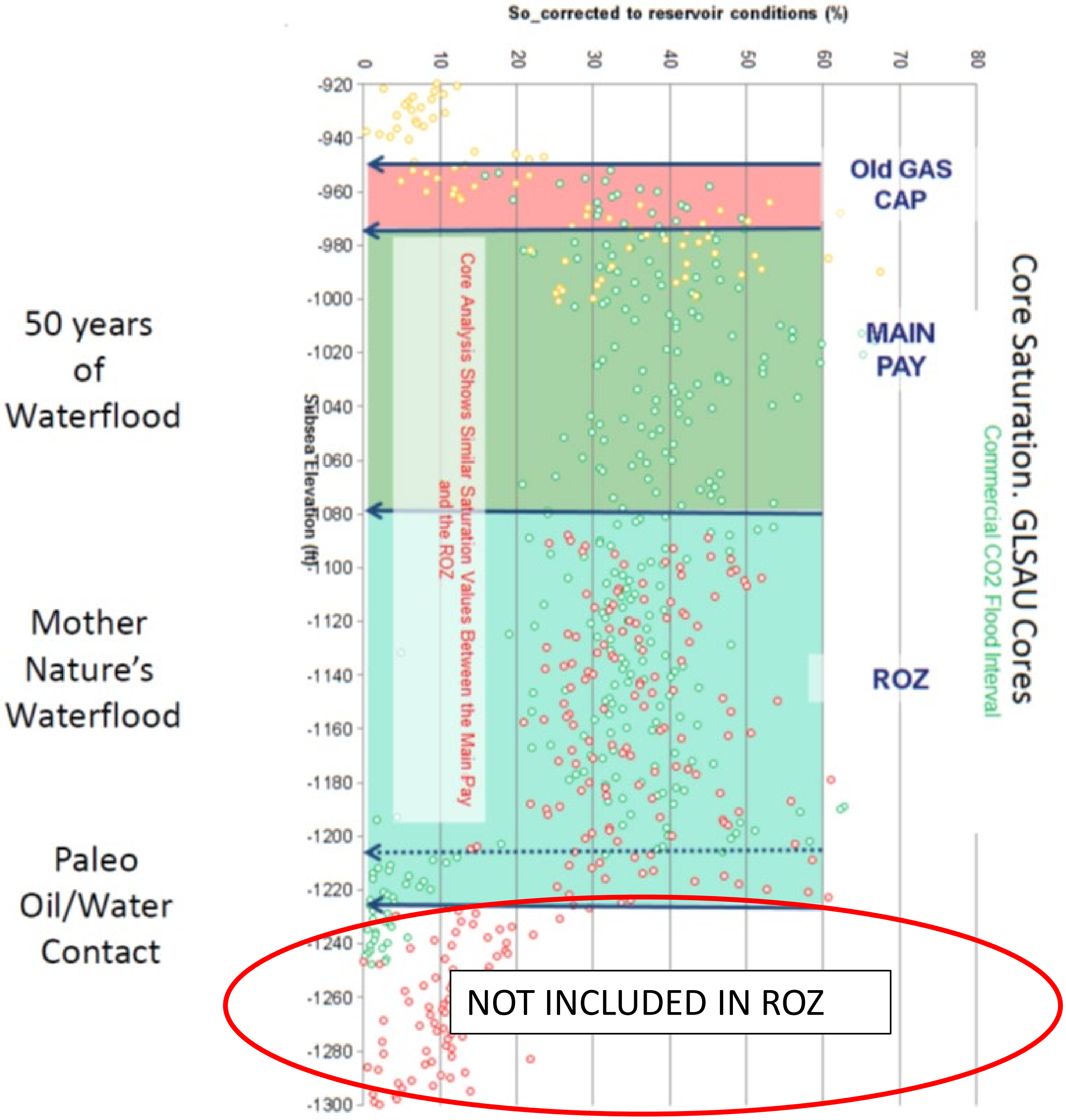


Figure adapted from Trentham, R. and Melzer, S., 2016.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4

NETHERLAND, SEWELL & ASSOCIATES, INC.

MCA 358
Pressure Core RI vs Sw

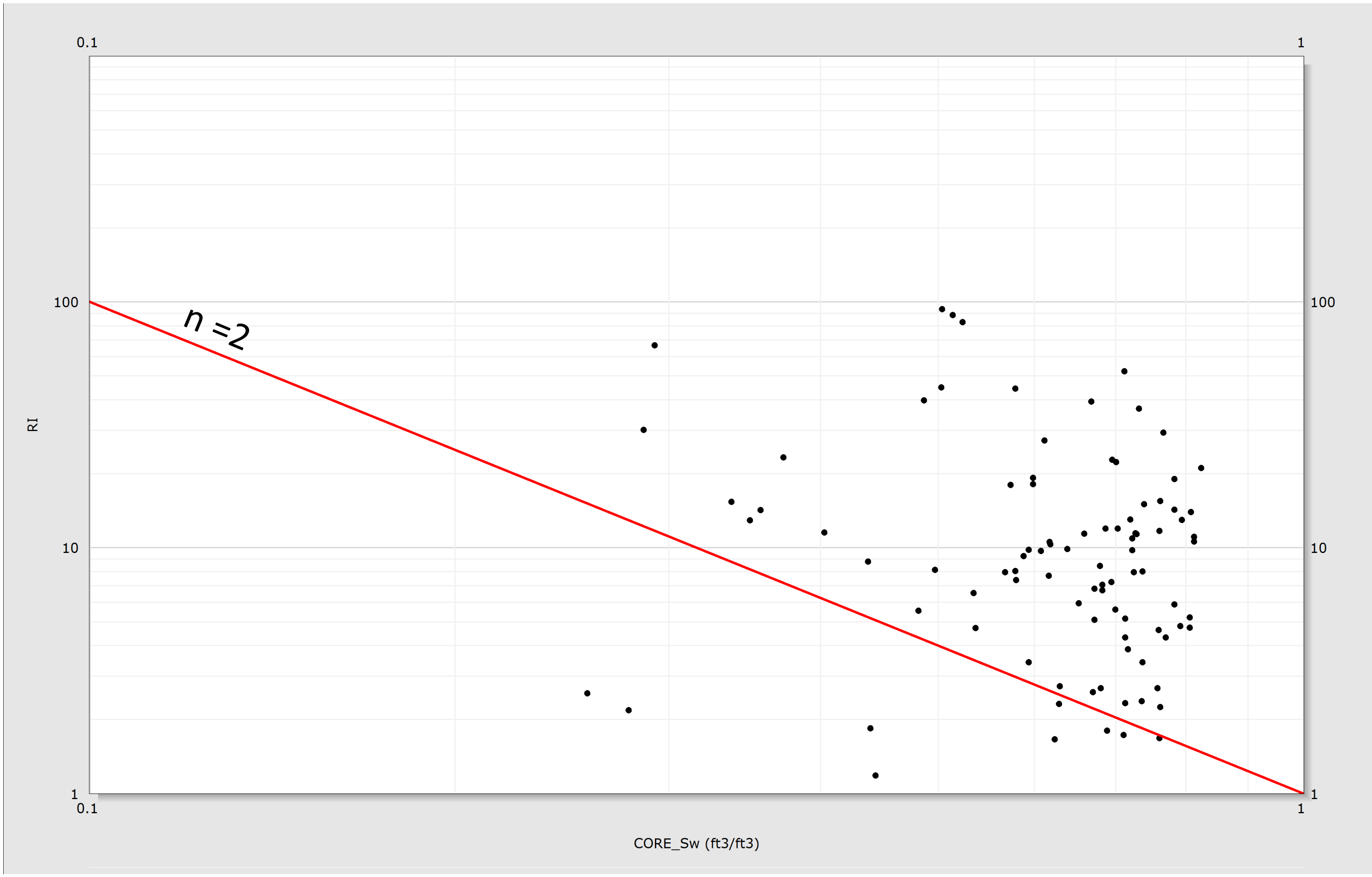
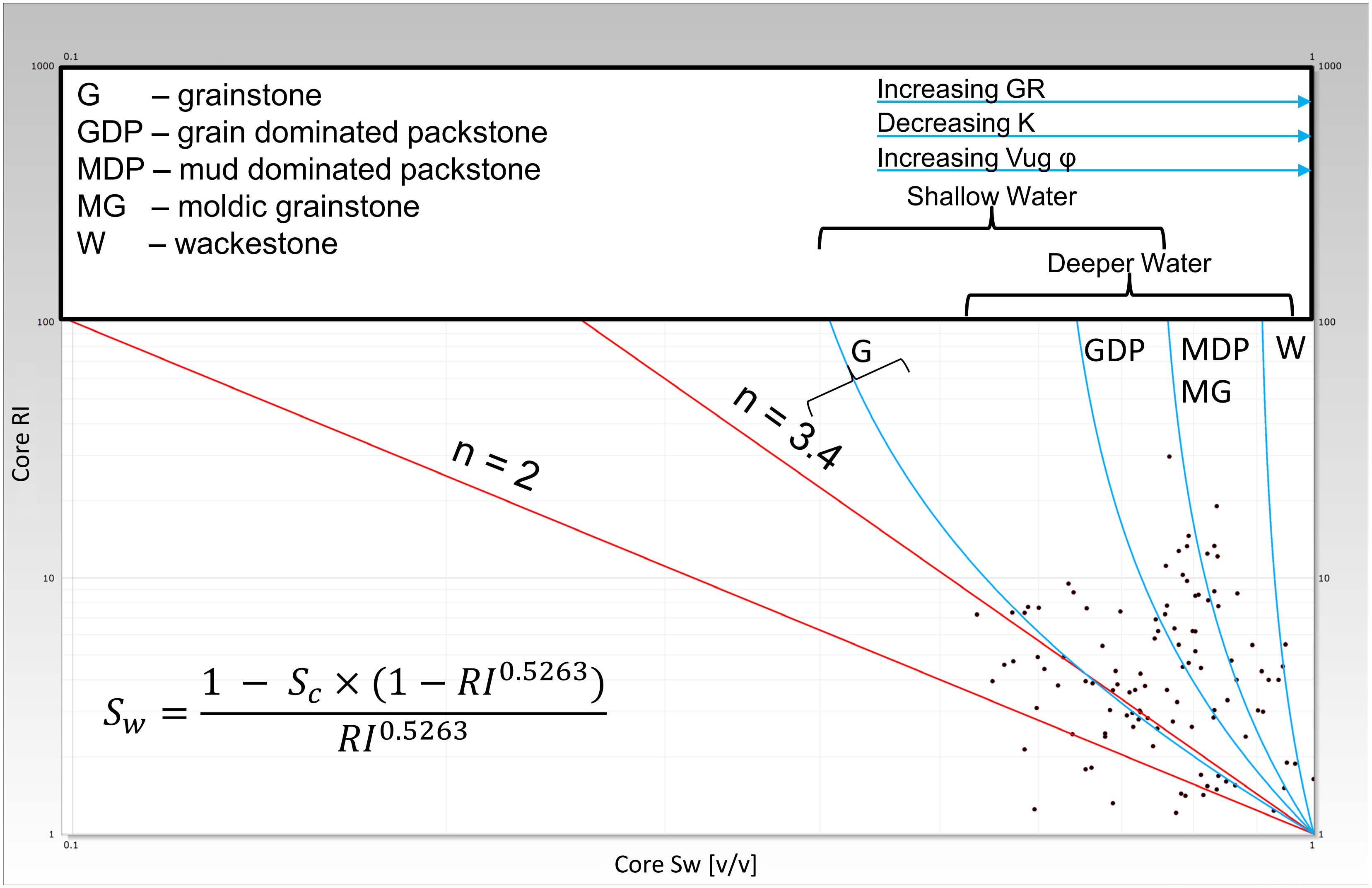


Figure 5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

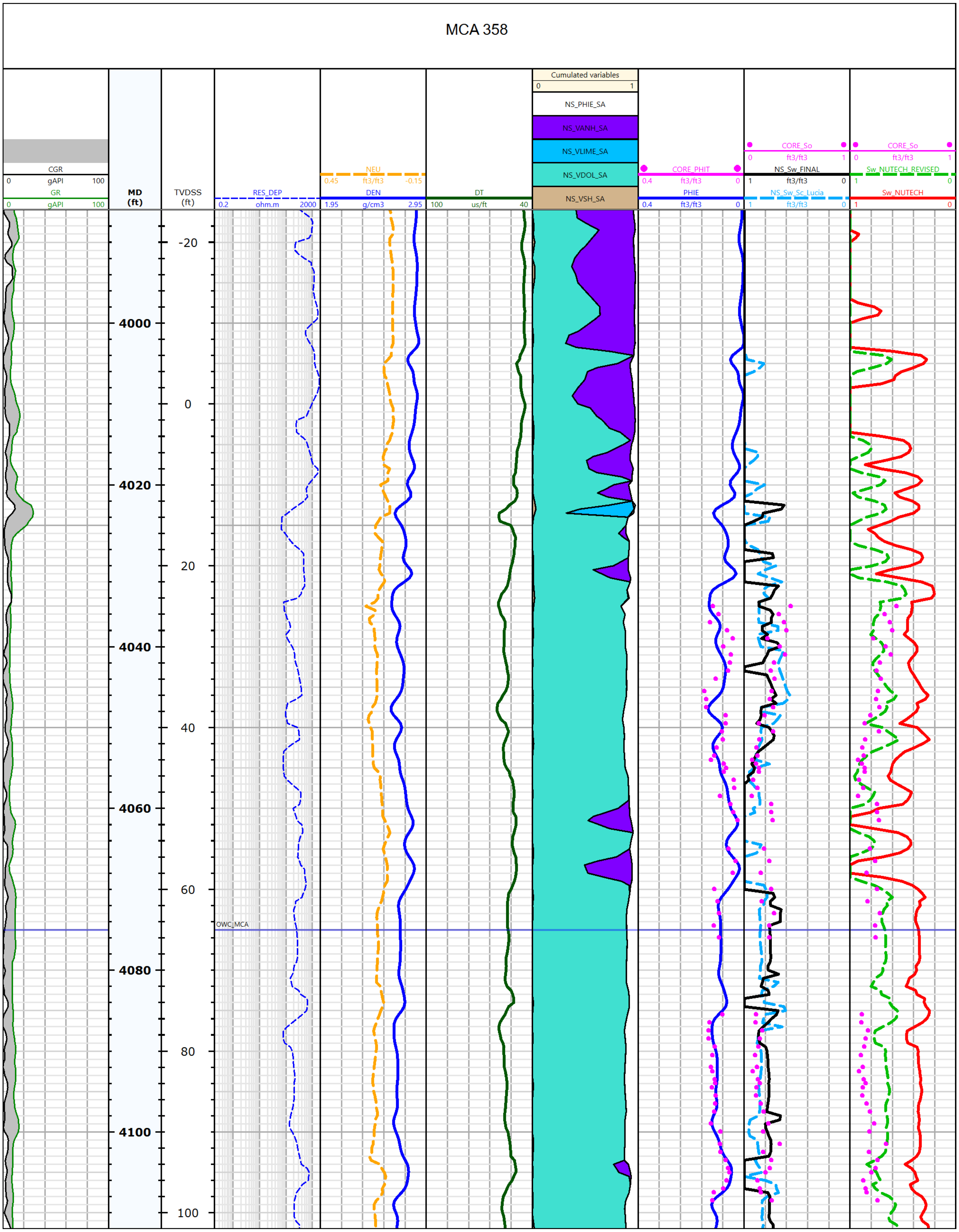
EMSU 679
Core RI vs Sw with Sc Curves



$$S_w = \frac{1 - S_c \times (1 - RI^{0.5263})}{RI^{0.5263}}$$

Figure 6

NETHERLAND, SEWELL & ASSOCIATES, INC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions. Figure 7

NETHERLAND, SEWELL & ASSOCIATES, INC.

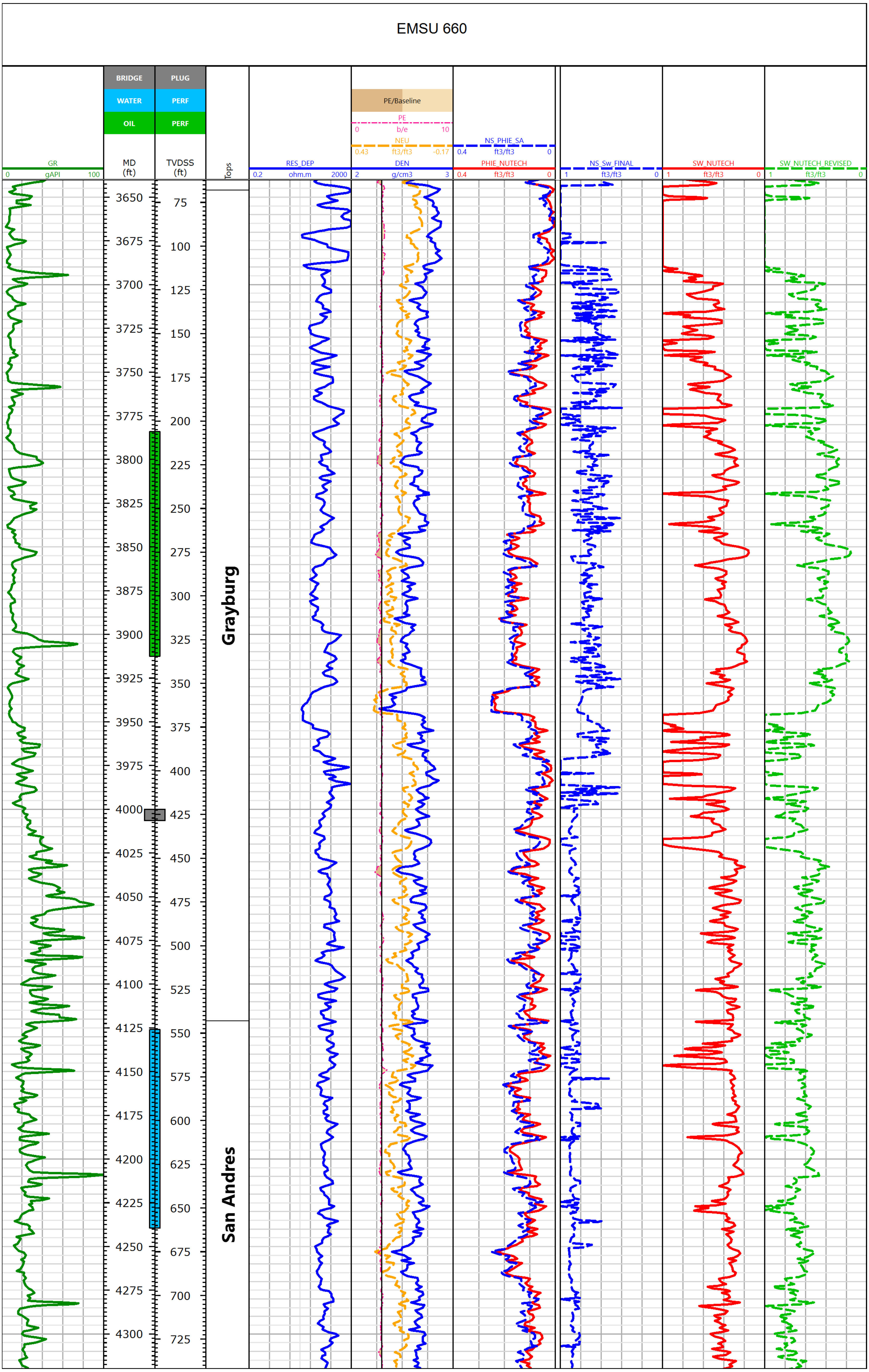


Figure 8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Submit 3 Copies to Appropriate District Office

State of New Mexico
Energy, Minerals and Natural Resources Department

Form C-103
Revised 1-1-89

DISTRICT I
P.O. Box 1980, Hobbs, NM 88240

DISTRICT II
P.O. Drawer DD, Artesia, NM 88210

DISTRICT III
1000 Rio Brazos Rd., Aztec, NM 87410

OIL CONSERVATION DIVISION

P.O. Box 2088
Santa Fe, New Mexico 87504-2088

WELL API NO.
30 025 31585

5. Indicate Type of Lease STATE [ ] FEE [X]

6. State Oil & Gas Lease No.
B-2052-3

SUNDRY NOTICES AND REPORTS ON WELLS

(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name
NORTH MONUMENT GRAYBURG SAN ANDRES UNIT BLOCK 5

1. Type of Well: OIL WELL [X] GAS WELL [ ] OTHER

2. Name of Operator
AMERADA HESS CORPORATION

8. Well No.
22

3. Address of Operator ATTN: ONSHORE DRLG. SVS.
1201 LOUISIANA, SUITE 700, HOUSTON, TX. 77002

9. Pool name or Wildcat
EUNICE MONUMENT G/SA

4. Well Location
Unit Letter F : 2605 Feet From The NORTH Line and 2630 Feet From The WEST Line

Section 19 Township 19S Range 37E NMPM LEA County

10. Elevation (Show whether DF, RKB, RT, GR, etc.)
3684.3 GR

11. Check Appropriate Box to Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK [ ]	PLUG AND ABANDON [ ]	REMEDIAL WORK [ ]	ALTERING CASING [X]
TEMPORARILY ABANDON [ ]	CHANGE PLANS [ ]	COMMENCE DRILLING OPNS. [X]	PLUG AND ABANDONMENT [ ]
PULL OR ALTER CASING [ ]		CASING TEST AND CEMENT JOB [X]	
OTHER: [ ]		OTHER: [ ]	

12. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work) SEE RULE 1103.

GRACE DRILLING SPUD AN 17-1/2" HOLE @ 3:00 P.M. 07/29/92. SET 10 JTS. (410') 13-3/8" 48# H-40 ERW 8RS R-3 CASING IN A 17-1/2" HOLE. B.J. SERVICES CEMENTED W/428 SXS CLASS "C" CEMENT + 2% A7, 1/4#/SX C.F. SW = 14.8, SY = 1.32. CIRC. 100 SXS CEMENT TO PITS. PLUG DOWN AT 3:45 A.M. 07/30/92. TESTED CASING TO 1000 PSI FOR 30 MINUTES. SET 84 JTS. (3673') 9-5/8" 36# K-55 ERW R-3 ST&C 8RD IN A 12-1/4" HOLE. B.J. SERVICES CEMENTED WITH 510 SXS CLASS "C" WITH 2% A-2 + 10% A-5 + 1/4#/SX C.F. SW = 14.2, SY = 1.59. TAILED WITH 530 SXS CLASS "H", SW = 16.4, SY 1.06. PLUG DOWN AT 2:30 P.M. 08/10/92. TESTED CASING TO 1500 PSI FOR 30 MINUTES. SET 109 JTS. (4550') 7" CASING IN 8-3/4" HOLE AS FOLLOWS: 95 JTS (3926') OF 7" 20# K-55 8RS R-3 AND 14 JTS (624') 7" 26# K-55 8RL R-3 AND DV TOOL AT 2599'. B.J. SERVICES CEMENTED WITH 65 SXS CLASS "C" LITE + 5#/SX A-5 + 1/4#/SX C.F. SW = 12.5, SY 2.04. TAILED WITH 195 SXS CLASS "C" + 3% A-9 + 0.9% FL-20 + 0.2% FP-8 + 1/4#/SX C.F., SW = 14.4, SY = 1.22. OPENED DV TOOL, PUMPED 235 SXS CLASS "C" LITE + 5#/SX A-5 + 1/4#/SX C.F., SW = 12.5, SY = 2.04. TAILED W/50 SXS CLASS "C" + 2% A-7 SHIFTED SLEEVE AND PRESSURED TO 2400 PSI 9:00 P.M. 08/26/92. CIRC. BACK 15 SXS CEMENT. RELEASED RIG AND TURNED WELL OVER TO PRODUCTION FOR COMPLETION.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Betsy Williams TITLE Petroleum Engineer DATE 8-28-92

TYPE OR PRINT NAME Betsy Williams TELEPHONE NO. (713)658-9770

(This space for State Use)

APPROVED BY ORIGINAL SIGNED BY JERRY SEXTON DISTRICT I SUPERVISOR TITLE DATE SEP 04 '92

CONDITIONS OF APPROVAL, IF ANY:

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 9

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

AMERADA HESS CORPORATION

P. O. DRAWER "D"
MONUMENT, NEW MEXICO 88265

August 12, 1992

New Mexico Oil Conservation Commission
Oil & Gas Division
P. O. Box 1980
Hobbs, New Mexico 88240

Dear Sir,

On August 8, 1992, 50 net bbls. crude oil was transported from NMGSAU Battery No. 26, North Monument Grayburg San Andres Field, and delivered to NMGSAU Well No. 522 located in Sec. 19, T19S, R37E, Lea County, N.M.

Oil was mixed with drilling mud for drilling operations and will not be recovered.

If additional information is needed, please contact us at your earliest convenience.

Sincerely,

R. L. Wheeler, Jr.

xc: Prod. & Admin. Svc. - Tulsa
Seminole

PRINTED IN U.S.A.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

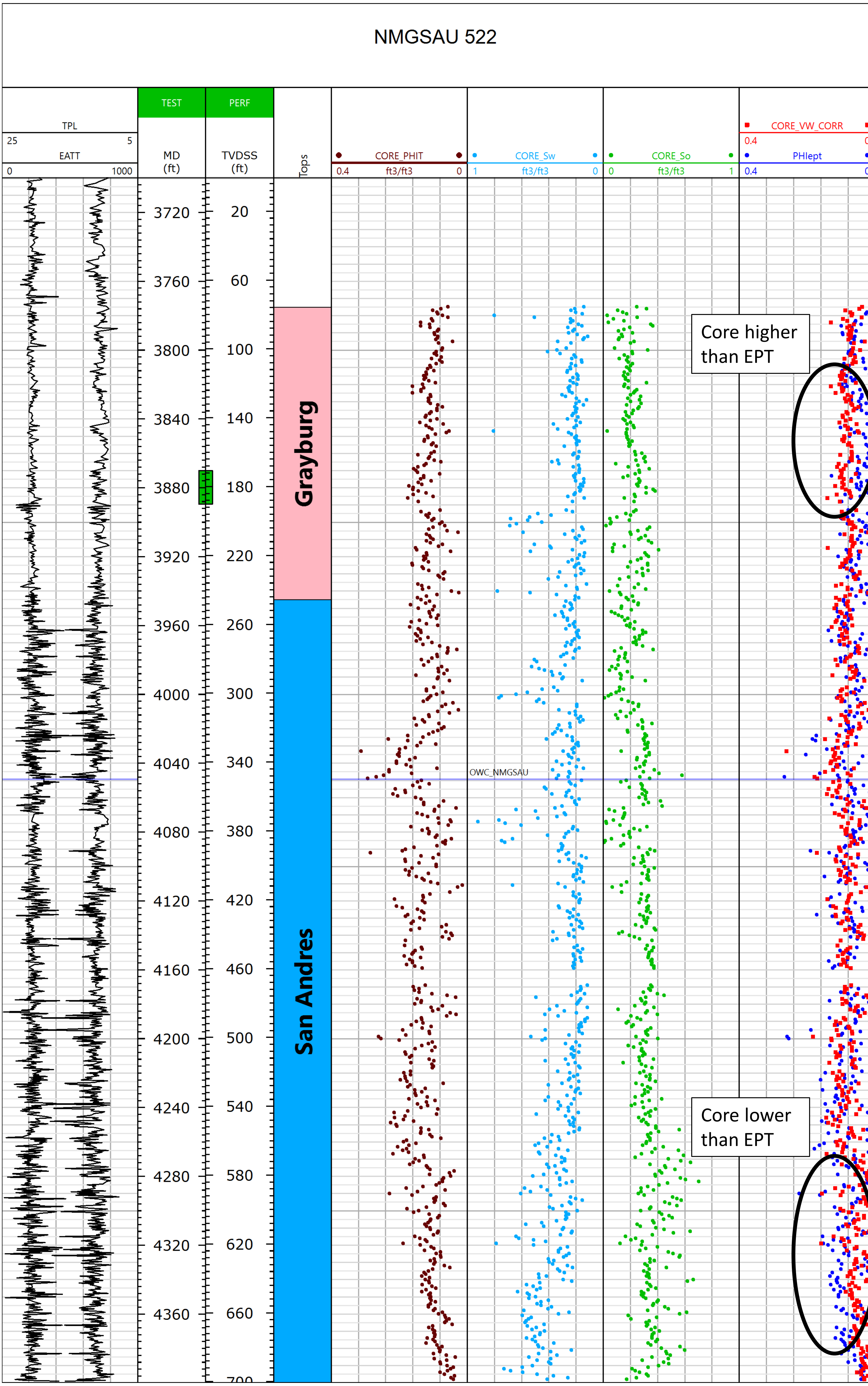


Figure 11

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Submit 5 Copies
Appropriate District Office
DISTRICT I
P.O. Box 1980, Hobbs, NM 88240

DISTRICT II
P.O. Drawer DD, Artesia, NM 88210

DISTRICT III
1000 Rio Brazos Rd., Aztec, NM 87410

State of New Mexico
E v, Minerals and Natural Resources Departmer

Form C-104
Revised 1-1-89
See Instructions
at Bottom of Page

OIL CONSERVATION DIVISION

P.O. Box 2088
Santa Fe, New Mexico 87504-2088

REQUEST FOR ALLOWABLE AND AUTHORIZATION TO TRANSPORT OIL AND NATURAL GAS

I.

Operator: AMERADA HESS CORPORATION	Well API No.: 30-025-31585
Address: DRAWER D, MONUMENT, NEW MEXICO 88265	

Reason(s) for Filing (Check proper box): New Well [X]; Recompletion [ ]; Change in Operator [ ]
Change in Transporter of: Oil [ ] Dry Gas [ ]; Casinghead Gas [ ] Condensate [ ]
Other (Please explain): LAID FLOWLINE TO NMGSAU BTRY. #21.

If change of operator give name and address of previous operator

II. DESCRIPTION OF WELL AND LEASE

Lease Name	Well No.	Pool Name, Including Formation	Kind of Lease State, Federal or Fee	Lease No.
BLK. 5 NORTH MONUMENT G/SA UNIT	22	EUNICE MONUMENT G/SA		B-2052-3

Location
Unit Letter F : 2605 Feet From The NORTH Line and 2630 Feet From The WEST Line
Section 19 Township 19S Range 37E , NMPM, LEA County

III. DESIGNATION OF TRANSPORTER OF OIL AND NATURAL GAS

Name of Authorized Transporter	Address (Give address to which approved copy of this form is to be sent)
Oil [X] or Condensate [ ]: SHELL PIPELINE CORPORATION	P.O. BOX 2648, HOUSTON, TEXAS 77001
Casinghead Gas [X] or Dry Gas [ ]: WARREN PETROLEUM COMPANY	P.O. BOX 1589, TULSA, OKLAHOMA 74102

If well produces oil or liquids, give location of tanks.	Unit	Sec.	Twp.	Rge.	Is gas actually connected?	When ?
		19	19S	37E	YES	11-08-92

If this production is commingled with that from any other lease or pool, give commingling order number:

IV. COMPLETION DATA

Designate Type of Completion - (X)	Oil Well	Gas Well	New Well	Workover	Deepen	Plug Back	Same Res'v	Diff Res'v
	X		X					

Date Spudded: 07-29-92	Date Compl. Ready to Prod.: 11-05-92	Total Depth: 4,550'	P.B.T.D.: 3,986' DOD 4,490'
Elevations (DF, RKB, RT, GR, etc.): 3684.3' GR	Name of Producing Formation: EUNICE MONUMENT G/SA	Top Oil/Gas Pay: 3,870'	Tubing Depth: 3,905'
Perforations: 3,870'-3,889' & fr. 3,915'-3,952' NOTE: RBP @ 3,908'			Depth Casing Shoe

TUBING, CASING AND CEMENTING RECORD

HOLE SIZE	CASING & TUBING SIZE	DEPTH SET	SACKS CEMENT
17-1/2"	13-3/8"	410'	428 SKS. CLASS "C"
12-1/4"	9-5/8"	3,673'	510 SKS. "C" & 530 SKS. "H"
8-3/4"	7"	4,550'	545 SKS. CLASS "C"
	2-7/8"	3,905'	

V. TEST DATA AND REQUEST FOR ALLOWABLE

OIL WELL (Test must be after recovery of total volume of load oil and must be equal to or exceed top allowable for this depth or be for full 24 hours.)

Date First New Oil Run To Tank: 11-05-92	Date of Test: 11-26-92	Producing Method (Flow, pump, gas lift, etc.): PUMPING	
Length of Test: 24 HOURS	Tubing Pressure	Casing Pressure	Choke Size
Actual Prod. During Test	Oil - Bbls.: 190	Water - Bbls.: 170	Gas - MCF: 300

GAS WELL

Actual Prod. Test - MCF/D	Length of Test	Bbls. Condensate/MMCF	Gravity of Condensate
Testing Method (pitot, back pr.)	Tubing Pressure (Shut-in)	Casing Pressure (Shut-in)	Choke Size

VI. OPERATOR CERTIFICATE OF COMPLIANCE

I hereby certify that the rules and regulations of the Oil Conservation Division have been complied with and that the information given above is true and complete to the best of my knowledge and belief.

R.L. Wheeler Jr.
Signature
R.L. WHEELER, JR. SUPV. ADM. SVCS.
Printed Name Title
11-30-92 (505) 393-2144
Date Telephone No.

OIL CONSERVATION DIVISION

Date Approved NOV 30 '92

By ORIGINAL SIGNED BY JERRY SEXTON DISTRICT I SUPERVISOR

Title

INSTRUCTIONS: This form is to be filed in compliance with Rule 1104
1) Request for allowable for newly drilled or deepened well must be accompanied by tabulation of deviation tests taken in accordance with Rule 111.
2) All sections of this form must be filled out for allowable on new and recompleted wells.
3) Fill out only Sections I, II, III, and VI for changes of operator, well name or number, transporter, or other such changes.
4) Separate Form C-104 must be filed for each pool in multiply completed wells.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Apache

November 11, 2016

NMGSAU # 522
API # 30-025-31585
Lea County, NM
Production Casing: 7" 20 & 26# Set @ 4,550'
Producing Interval: **3,814-3,924'**

Objective: Isolate lower Grayburg and add perforations in the San Andres

Procedure:

1. POOH with rods and tbg
2. Pick up 2-7/8" workstring
3. RIH with packer and pressure test casing to 500 psi down to 3,800'
4. POOH with packer
5. RIH with cmt retainer and set @ 3,805'
6. Pressure up casing to 300 psi
7. Squeeze perfs from 3,814-924' with 200 sxs of cmt
8. WOC for 12 hours
9. RIH with bit, bit sub, junk baskets, drill collars and workstring
10. Drill out cmt and circulate bottoms up
11. Drill out CIBP @ 3,931' and circulate bottoms up
12. POOH and empty junk baskets
13. Pick up rock bit, bit sub, drill collars and 2-7/8" workstring
14. Drill out cmt and cmt retainer @ 3,986' and 4,000' respectively
15. Clean wellbore down to 4,400' and circulate 2% KCL water on bottom (from 4,400 to 4,200')
16. POOH laying down workstring
17. MIRU wireline
18. Perforate with casing gun (6 spf, 60º phasing)
    - 4,297-310'
19. Pick up Model R packer, SN and 2-7/8" production tbg
20. Set packer @ 4,280'
21. Open bypass in packer and circulate 750 gallons of 15% HCL NEFE to bottom
22. Break down formation and swab test well for 2 days. If a commercial completion is established
23. RIH with rod pump
24. Return well to production
25. If a commercial completion is not established
26. POOH with packer
27. RIH and set a CIBP @ 4,285'

APACHE CORPORATION 303 VETERANS AIRPARK LANE / SUITE 3000 / MIDLAND, TX 79705-4561 TEL (432)818-1000

28. Perforate with casing gun (6spf, 60º phasing)
    - 4,247-52'
29. Pick up Model R packer, SN and 2-7/8" production tbg
30. Set packer @ 4,220'
31. Open bypass in packer and circulate 500 gallons of 15% HCL NEFE to bottom
32. Break down formation and swab test well for 2 days. If a commercial completion is established
33. RIH with rod pump
34. Return well to production
35. If a commercial completion is not established
36. POOH with packer
37. RIH and set a CIBP @ 4,225'
38. Perforate with casing gun (6spf, 60º phasing)
    - 4,101-09'
39. Pick up Model R packer, SN and 2-7/8" production tbg
40. Set packer @ 4,080'
41. Open bypass in packer and circulate 600 gallons of 15% HCL NEFE to bottom
42. Break down formation and swab test well for 2 days.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Apache Corporation – NMGSAU #522

Wellbore Diagram – Current

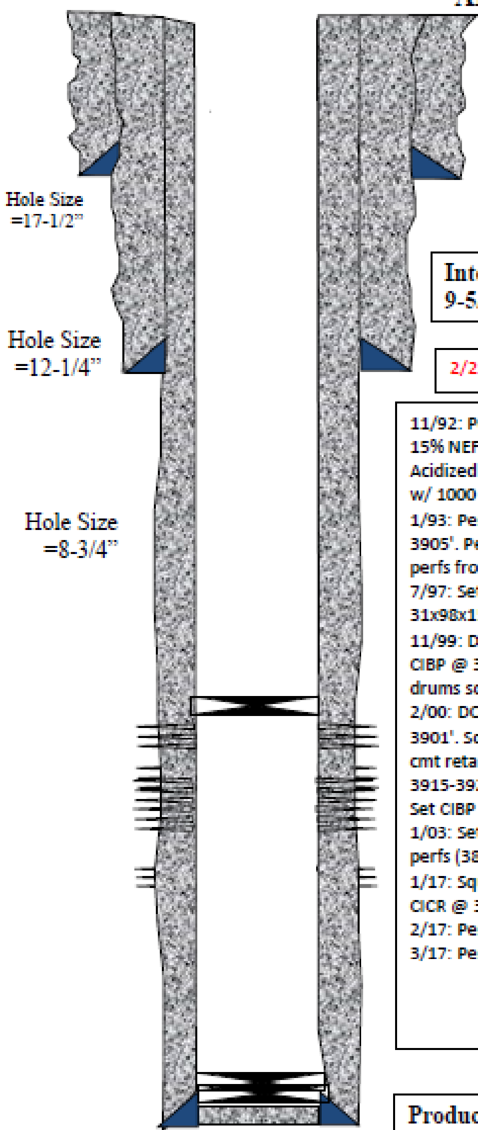
API: 30-025-31585

GL=3684'
KB=3695'
Spud:7/29/92

Date : 6/21/2016
K. Grisham

Surface Location

2605' FNL & 2630' FWL,
Lot F Sec 19, T19S, R37E, Lea County, NM



Surface Casing
13-3/8" K-55, 48# @ 410' w/ 428 sxs to surface

Intermediate Casing
9-5/8" 36#, K-55 @ 3,673' w/ 1040 sxs to surface

2/21: Set RBP @ 3800' to temporarily abandon

11/92: Perf fr/ 4025-4034.5'; 35-45.5'; 45-55'; 56-66'. (84 holes). Acidized w/ 2700 gals 15% NEFE. Sqz'd perfs w/ 153 sxs. Perf fr/ 3915-16'; 3916.5-26'; 35-40'; 45-52' w/ 2 jspf. Acidized w/ 2200 gals 15% NEFE. Perf fr/ 3870-76' & 81-89 w/ 2 jspf (32 holes). Acidized w/ 1000 gals 15% NEFE. Began flow test.

1/93: Perf fr/ 3814-22' w/ 2 jspf (17 holes). Spotted w/ 1300 gals 15% NEFE. Set CIBP @ 3905'. Perf fr/ 3859.5-3869.5 & 3850-3859' (40 shots) & fr/ 3838-3844' (12 holes). Acidized perfs from 3838-3889' w/ 2000 gals 15% NEFE. 175x137x0.

7/97: Set CIBP @ 3906'. Acidized fr/ 3814-3889' w/ 2400 gals 15% NEFE. Swabbed & RTP. 31x98x151.

11/99: DO CIBP @ 3906'. Tagged cmt retainer @ 3992'. Ran USIT log fr/ 3983-3538'. Set CIBP @ 3942'. Washed perfs fr/ 3814-3926' then acidized w/ 2000 gals 15% HCl. Dump 2 drums scale sqz w/ salt as diverter. RTP.

2/00: DO CIBP @ 3942'. & CO to cmt retainer @ 3986'. TIH w/ 7" cmt retainer & set @ 3901'. Sqz'd perfs fr/ 3915-3952' w/ 150 sxs, found cmt communicating to upper perfs. DO cmt retainer & cmt. Test sqz'd perfs & held ok. Ran log, indicated cmt behind perfs fr/ 3915-3926', 3935-3940' & 3945-3952'. Perf fr/ 3889-96' & fr/ 3906-24' w/ 2 jspf (46 holes). Set CIBP @ 3930'. Acidized perfs 3889-3924' w/ 2000 gals 15% HCl.

1/03: Set CIBP @ 3902' Reperf fr/ 3850-3876' & 3881-3889' w/ 2 jspf (70 holes). Acidized perfs (3850-3889') w/ 2000 gals 15% HCl. Swabbed & pushed CIBP down to CIBP @ 3931'.

1/17: Squeeze perfs: 3814-3924' w/400 sx. DO CIBP 3931-32', Mill over CIBP & push to CICR @ 3986'. Mill on CIPB/CICR and DO cmt to 4080' & fell out. RIH @ 4414' circ clean.

2/17: Perf 4300-4308' (48 holes). Acidize San Andres w/920 gal 15% HCL. Set CIBP @ 4285'

3/17: Perf 4247-52' @ 4 spf (20 holes). Acidize w/500 gal 15%. Set CIBP @ 4225'.

Production Casing
7" 20 & 26#, K-55 @ 4,550' w/ 545 sxs

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 15

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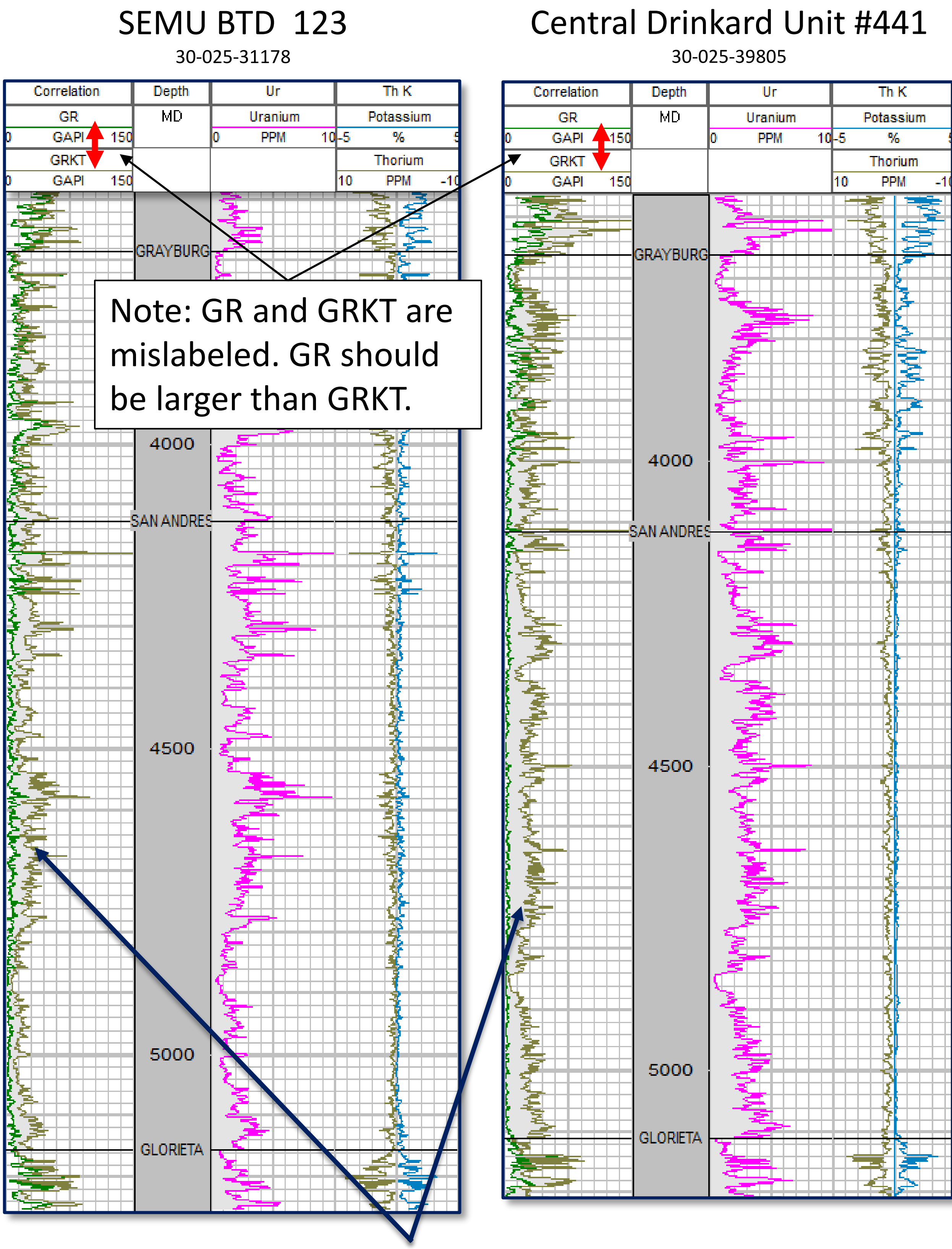

Uranium concentrations shaded in light gray. As you move deeper, uranium becomes more dominant features of gamma ray signal.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 16

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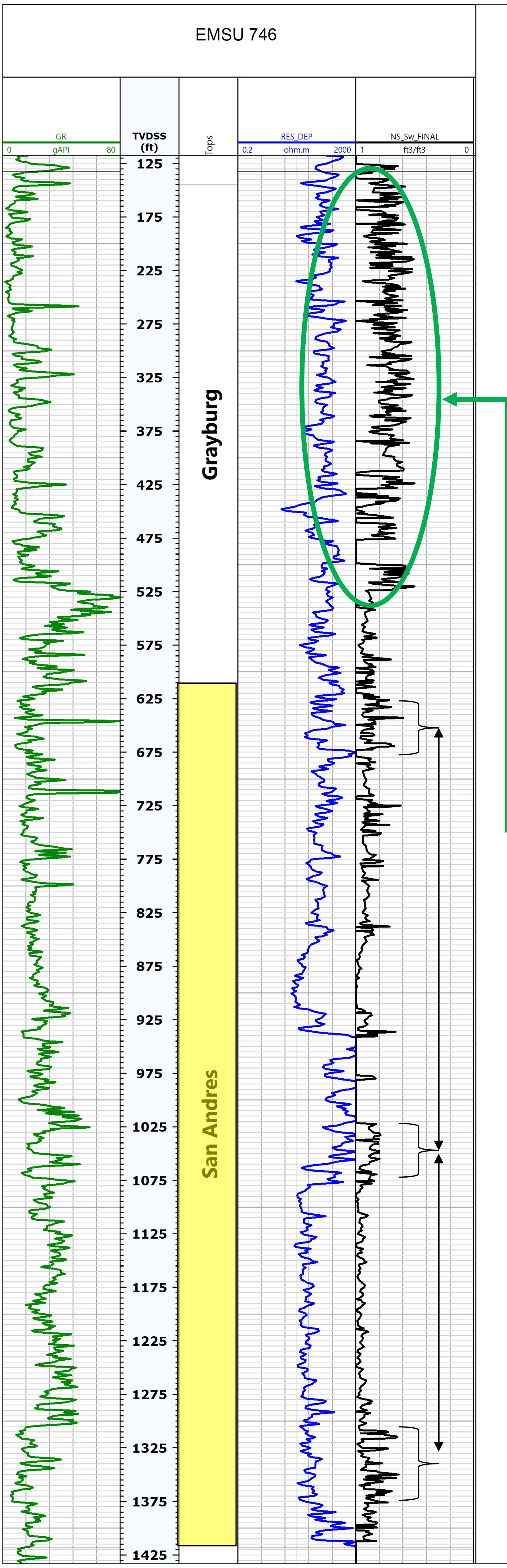
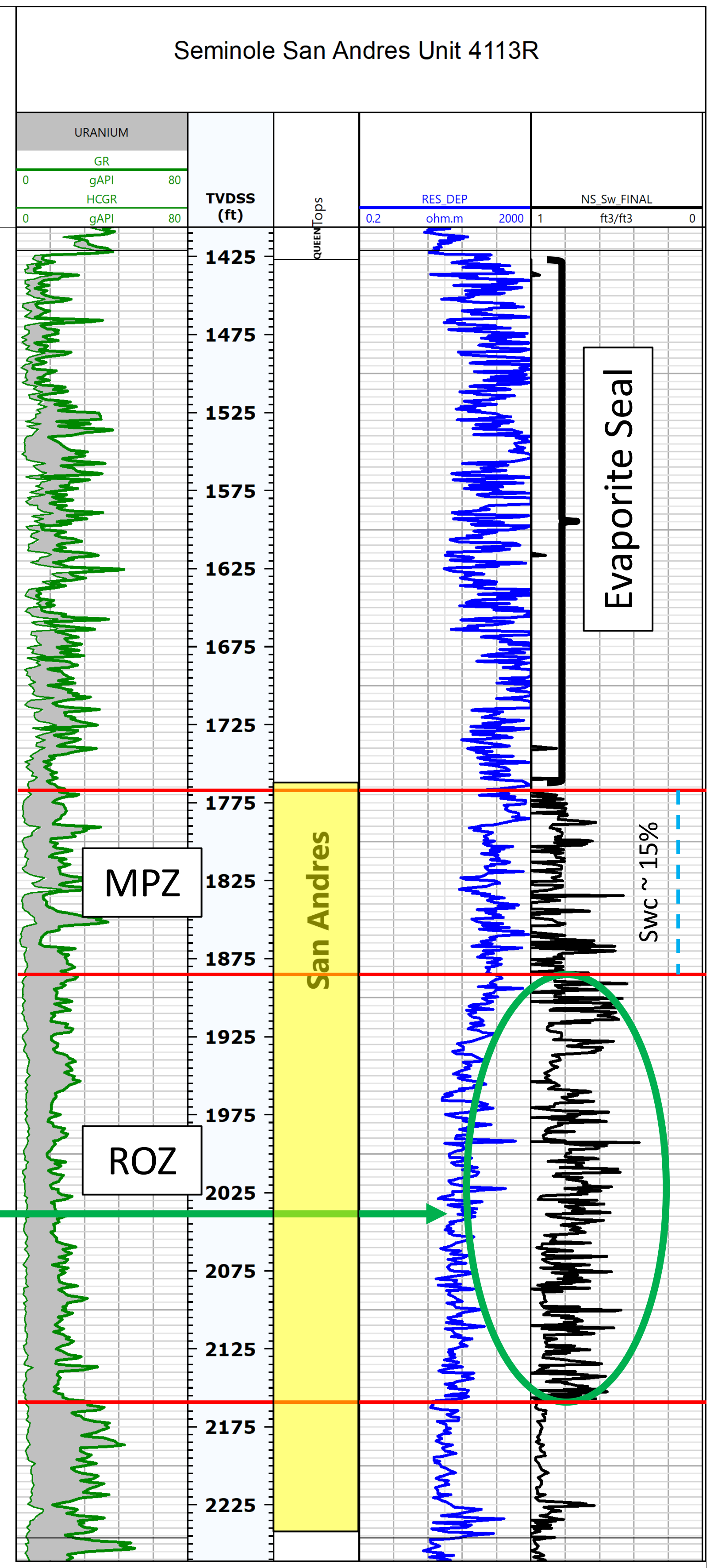
EMSU and SSAU ROZ Comparison





MPZ in SSAU has undergone 40+ years of CO_2 and water flooding and has average oil saturation ≈ 20%.

Notice very sparse thin regions of residual oil in the San Andres that are separated by over 100 feet. Average residual oil thickness in the San Andres is less than 2 ft

Conclusion: San Andres in EMSU is not ROZ and likely consists of abandoned migration paths.

Figure 17

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

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BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. D-5
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

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EMSU 746

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. D-6
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

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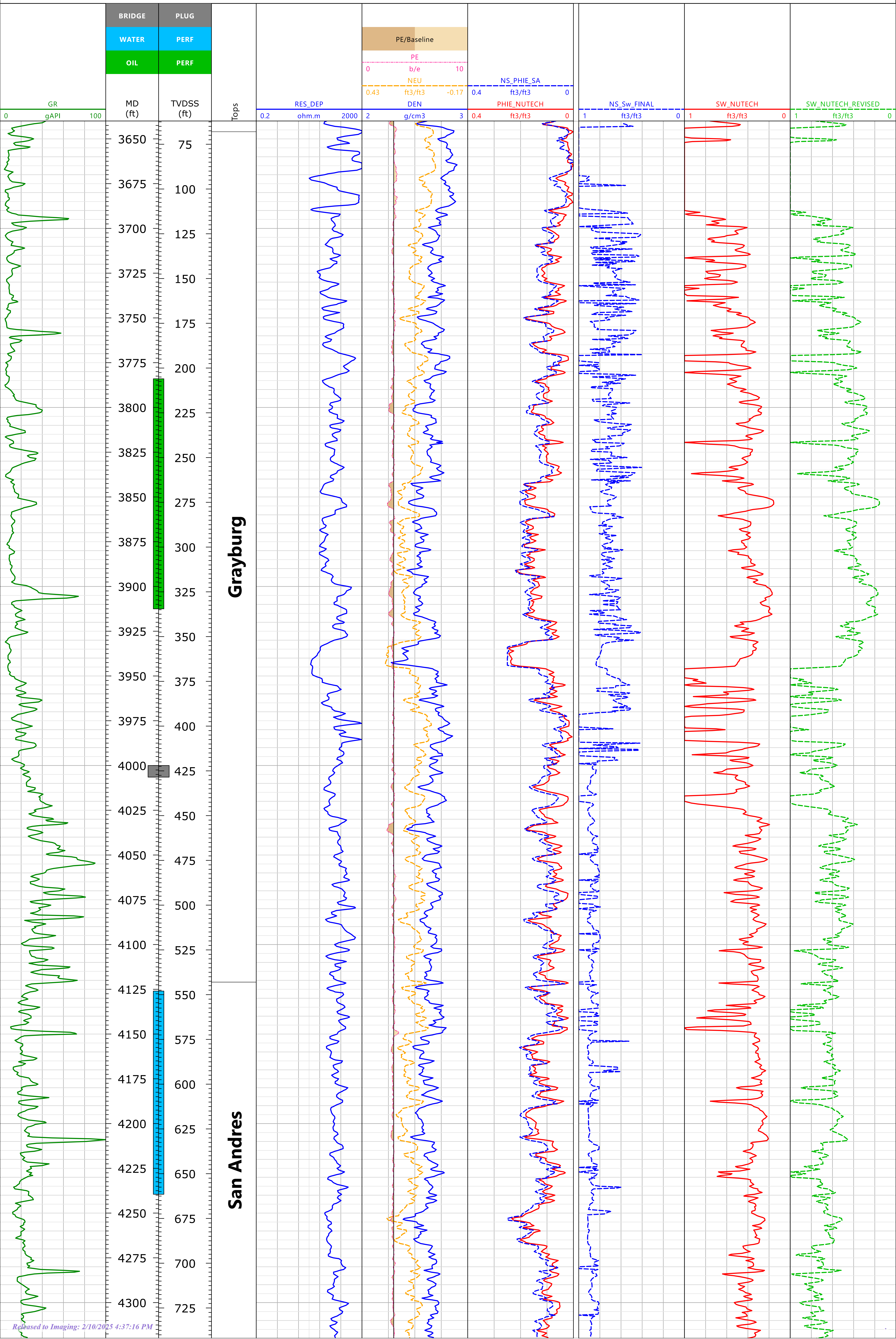
BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. D-7
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

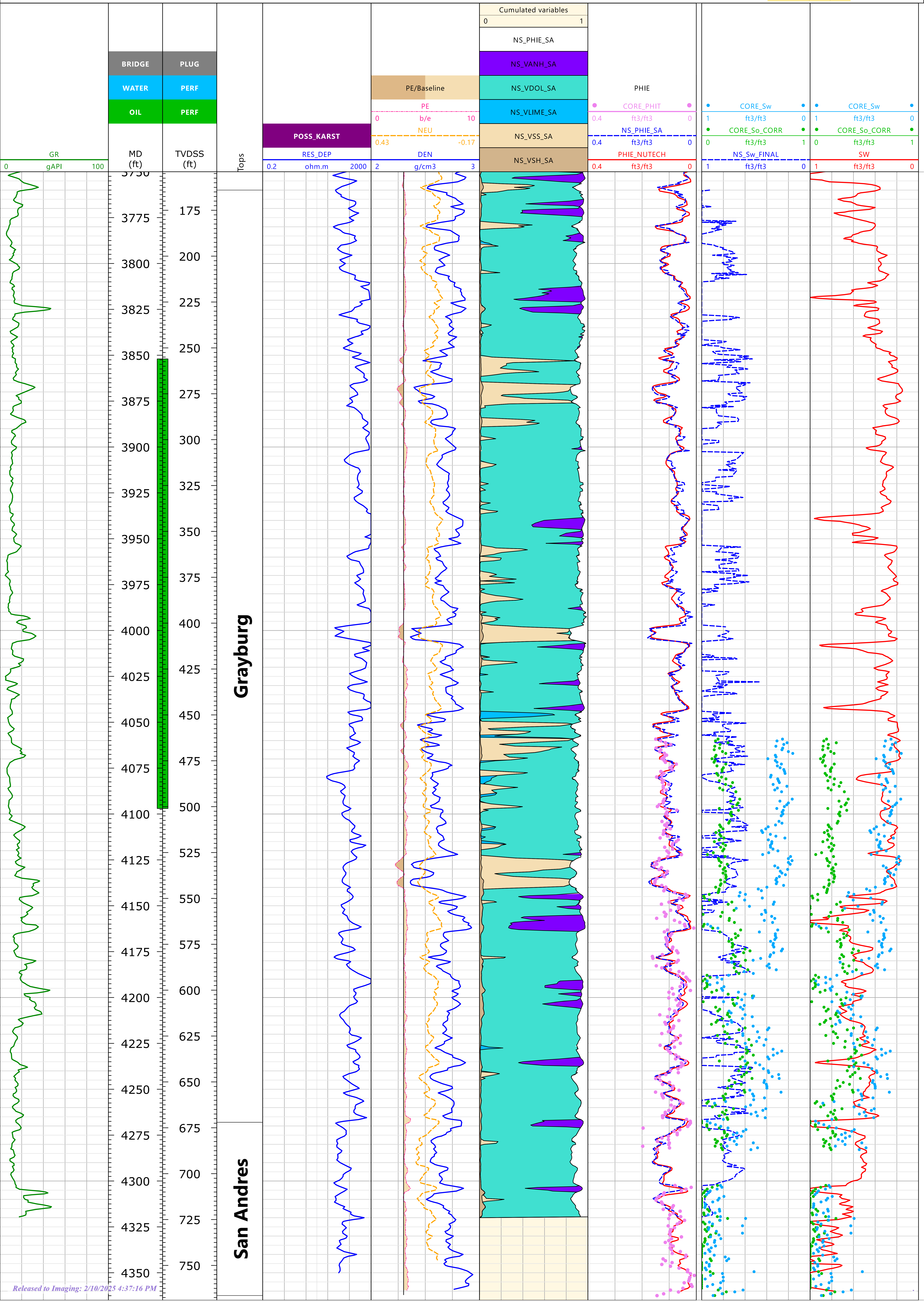
EMSU 660

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. D-8
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123



BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. D-9
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

EMSU 679



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

APPLICATION OF GOODNIGHT MIDSTREAM
PERMIAN, LLC FOR APPROVAL OF
SALTWATER DISPOSAL WELLS
LEA COUNTY, NEW MEXICO

CASE NO. 24123

APPLICATIONS OF GOODNIGHT MIDSTREAM
PERMIAN, LLC FOR APPROVAL OF
SALTWATER DISPOSAL WELLS
LEA COUNTY, NEW MEXICO

CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM
PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403
TO INCREASE THE APPROVED INJECTION RATE
IN ITS ANDRE DAWSON SWD #1,
LEA COUNTY, NEW MEXICO

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC
TO REVOKE INJECTION AUTHORITY,
LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24027

Rebuttal Report of: William J. Knights, P.G.
February 6, 2025

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. E
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

NETHERLAND, SEWELL & ASSOCIATES, INC.

TABLE OF CONTENTS

REBUTTAL EXHIBIT E-1

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INTRODUCTION

My name is William J. Knights. I work for Netherland, Sewell & Associates, Inc. (NSAI) as Vice President and Senior Technical Advisor. I have been with NSAI since 1991.

I provided direct written testimony in these cases that were filed with the Commission on August 26, 2024, on behalf of Goodnight Midstream Permian, LLC (Goodnight). I have been asked to prepare rebuttal testimony in response to witness testimony of Empire Petroleum Corporation (Empire) that (I) there are economic concentrations of oil or potential for a residual oil zone (ROZ) in the San Andres disposal zone within the EMSU, based on estimated calculations of oil-in-place (OIP) in the EMSU; (II) there is evidence of communication between the Grayburg Reservoir and Goodnight's San Andres Aquifer disposal zone; and (III) the North Monument Unit, Hobbs Field, and Vacuum Field are analogous to the Grayburg Reservoir and San Andres Aquifer, indicating the presence of economic hydrocarbons in the San Andres Aquifer in the Eunice Monument South Unit (EMSU).

SUMMARY OF CONCLUSIONS

The following is a summary of my opinions, all of which are rendered within a reasonable degree of professional certainty:

I. The oil saturation (S_o) models provided by NuTech Energy Alliance Ltd (Nutech) show significant discrepancies, with the revised model estimating significantly less OIP than the original model. Nutech's analysis fails to incorporate key methods for validating petrophysical models - such as reviewing past operators' conclusions, theoretical analysis, and direct test data comparison - which raises concerns about the accuracy of their analysis. Production tests in wells drilled after waterflooding showed that Nutech's models significantly overpredicted the amount of oil and underestimated water in the reservoir compared to actual production data, which showed minimal oil recovery and high water volumes. The NSAI model, in contrast, aligned more closely with the observed production, indicating that Nutech's models may be unreliable for estimating S_o in lower-porosity reservoirs.

II. Geologic documentation, including various studies and models, does not support vertical communication between the Grayburg Reservoir and the San Andres Aquifer within the EMSU. Several factors, such as distinct permeability barriers, injection-withdrawal ratio balancing, water encroachment from downdip edges, and pressure isolation, confirm vertical isolation within the Grayburg Reservoir. The absence of significant faults or fractures across the EMSU and the lack of evidence for continuous fluid migration further supports this isolation. Additionally, data from wells, including the EMSU 239 well, show that water production is consistent with edge-water drive rather than communication with the deeper San Andres Aquifer, reinforcing the conclusion that the Grayburg Reservoir and San Andres Aquifer are separate and isolated.

III. The Grayburg Reservoir and San Andres Aquifer share similar depositional, structural, and petrophysical characteristics across the Permian Basin, but using specific fields as analogs requires a detailed understanding of geologic and engineering similarities. Many referenced fields, such as Lovington, Maljamar, and Vacuum, are geographically and structurally isolated from the Central Basin Platform (CBP), making them a poor analog to estimate EMSU S_o. While nearby fields like Hobbs and Eunice have perforations in the Grayburg Reservoir and San Andres Aquifer, they are stratigraphically and geographically distinct from the EMSU. Although the EMSU, EMSU B, and North Monument Unit primarily produce from the Grayburg Reservoir, they are geographically and stratigraphically separated and would have limited relevance to the EMSU S_o.

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GEOLOGIC CONCLUSIONS

I. Concentration of Hydrocarbons - Quality of Potential

The evidence supporting sufficient OIP concentrations below the producing oil-water contact (POWC) that would warrant economic development is weak. The primary data to support such volumes were generated using petrophysical analysis by Nutech. The estimates of S_o and water saturation in the Nutech petrophysical models are inconsistent with production tests, both above and below the POWC.

The S_o presented by Nutech used two different petrophysical models for calculating S_o, resulting in drastically different results. Nutech's original model estimates more than double the original OIP compared to the revised model. There are oil and gas industry standards for evaluating the reasonableness of a petrophysical model. One important method involves reviewing conclusions reached by previous operators, engineers, geologists, and management. Another method for evaluating petrophysical models is theoretical analysis, using concepts, logic, and reasoning to ensure that equations and basic assumptions are scientifically sound and compatible with the current scientific understanding. A third method is empirical or direct data analysis, comparing the calculated results to actual observations of fluid flows from the reservoirs. Based on the review of Nutech's analysis, none of these methods appear to have been implemented.

The EMSU area was discovered, drilled, and operated by Marland Oil Company and Continental Oil Company in the 1930s. Since then, 23 companies have drilled and produced in this area without finding any economic potential below -350 feet (ft) true vertical depth subsea (TVDSS). This group of successful oil and gas operators, with direct real-time evidence from 474 wells drilled in the field, concluded through their actions that there was no potential for commercial oil development below -350 ft TVDSS. The subsequent unitization and operation of the EMSU involved the combined geologic, engineering, and operational expertise of world-class major oil companies such as Conoco Incorporated, Exxon Company, and Gulf Oil Corporation, yet none of them concluded that there was any reasonable economic potential below -350 ft TVDSS.

In the original Nutech model, no discernible decrease in S_o is observed with increasing depth. However, a decline in saturation with depth is a common characteristic of producing reservoirs and a key indicator of an ROZ in intervals below the POWC (Trentham, Meltzer, and Vance, 2012). In the revised Nutech model, S_o decreases with depth below the POWC, aligning with expected reservoir behavior.

In NSAI's analysis of oil saturation, we used a consistent porosity cutoff of 4 percent to evaluate the reasonableness of the three petrophysical models to conduct an empirical analysis. Using standard saturation cutoffs of greater than 40 percent S_o to determine productive conventional net pay, both of Nutech's petrophysical models indicate a significant amount of conventional pay above and below the established POWC in the EMSU. However, multiple tests above and below the POWC indicate very little oil and high water volumes, which appears to contradict Nutech's analysis. Above the POWC, both of Nutech's models produced the same results, with only slight variations in formation tops used in the revised analysis. Figure 1 shows the S_o values compared to the depths for the three petrophysical models. This analysis includes six wells (Figure 2) and uses standard conventional S_o cutoffs greater than 40 percent to determine productive net pay thickness across four subsea depth intervals across the wells. The original Nutech model estimated 924 ft of net oil pay, which is 69 percent of the total net thickness, and the revised Nutech model estimated 919 ft of net oil pay, which is 68 percent the total net thickness. In contrast, the NSAI model estimates 238 ft of net oil pay, which is 18 percent of the total net reservoir thickness above the POWC. Actual field production above the POWC averaged less than 10 percent oil cut during the period when the six petrophysical wells were logged. Both Nutech models indicate a greater net oil pay than wet reservoir thickness, which is contrary to the actual production data.

Significant differences are observed in the saturation calculations below the POWC. The original Nutech model estimates 1,952 ft of net oil pay, while the revised Nutech model estimates 782 ft of net oil pay. This revision represents a reduction of about 60 percent of the net oil pay and shows a substantial decrease in S_o. If both models are considered theoretically reasonable, this would indicate a high degree of uncertainty in the saturation calculations. In contrast, the NSAI model estimates only 78 ft of net oil pay below the POWC with significantly lower S_o than both Nutech models. Despite the significant reduction in calculated OIP, both Nutech models indicate substantially higher net oil pay and S_o than the NSAI model. These discrepancies highlight the considerable variation among the three models in predicting S_o distribution in the EMSU.

Another validation for petrophysical models is to compare net oil pay against actual production and test results from specific wells. The net oil pay and net wet reservoir thickness ratio should correspond to the relative oil and water production in the zone, where higher oil production correlates with greater net oil pay and higher water production corresponds to increased wet reservoir thickness.

The EMSU 658 and 660 wells, drilled in 2006, well after waterflood implementation, tested intervals above and below the POWC. These wells were selected as a practical test for the three petrophysical models. Initial field production in the 1930s had a very low water cut, with most wells producing water-free upon initial completion. However, by 1981, before waterflood began, the field-wide water cut had risen to 80 percent, indicating significant edge-water influx. By 2006, when the two wells were drilled and logged, the field-wide water cut had reached 96 percent above the POWC. The fluid saturation properties encountered in these two wells were drastically different compared to earlier wells, as they were logged decades after production, water influx, and water injection had commenced. The S_o determined in these two wells are considered representative of the field-wide average above the POWC in 2006, when they were drilled. Had these wells been logged before primary production and water influx had occurred, the S_o and OIP would have been significantly higher. Below the POWC, fluid conditions in these wells are more closely aligned with the initial reservoir fluid conditions, producing high water volumes.

A comparison of the S_o profile across the swept producing interval was made using the NSAI and Nutech models. The S_o in the revised Nutech model shows almost no water saturation in a zone that is producing 96 percent water cut above the POWC in the EMSU, while the very low S_o values in the NSAI model, within the same interval, are likely immovable concentrations of oil. The S_o values for each of the three models across different depth intervals, as well as for each of the tested intervals in the two key evaluation wells, are shown in Figure 3. Figure 4 shows that all three models overpredicted the relative oil volumes recovered. The intervals tested below the POWC recovered very little oil and large amounts of water. The swab test showed a 0.00 percent oil cut, and using an electrical submersible pump (ESP), this interval only recovered 0.10 percent oil cut in the EMSU 658 and 0.17 percent oil cut in the EMSU 660. For these tested zones, the original Nutech model estimates over 95 percent net oil pay in the EMSU 658 well and 86 percent in the EMSU 660 well. The revised Nutech model below the POWC estimates that over 30 percent of the net pay oil is productive in the EMSU 658 well and 14 percent in the EMSU 660 well. In comparison, the NSAI model below the POWC estimates up to 12 percent of the net pay to be oil productive in the EMSU 658 well and 7 percent in the EMSU 660 well. The estimates of net oil pay and wet reservoir thickness that were generated by the petrophysical models are not directly related to producing oil and water rates; however, comparisons of the three models show that the Nutech models predicted predominately oil production from the net pay analysis, while the NSAI model predicted predominantly water production, which more accurately reflects the recovery from these tests. The significantly high water volumes and low oil volumes recovered should not be overlooked, as they provide critical information about the amount of moveable oil present in these reservoir intervals. Although the petrophysical models estimate a significant amount of oil, the test data effectively invalidate both Nutech models, making them unreasonable interpretations of recoverable oil volumes and production.

In general, petrophysical models are more effective at determining fluid saturations in high-porosity systems with high fluid mobility, such as the significant fluid volumes recovered below the POWC in these tests. However, as porosity decreases and fluid volumes represent a smaller portion of the geologic system, accurately predicting saturations becomes increasingly challenging. It is imperative to validate a petrophysical model and fluid property estimates against actual test data. This increases the importance of doing an empirical check using actual well test data to assess the degree of certainty in the models. Nutech does not appear to have undertaken this standard

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industry review practice to assess its model. If the models do not reliably predict fluid mobility in the higher-porosity, fluid-rich intervals identified using conventional cutoffs, it stands to reason that the accuracy will be even lower in the more complex, lower-porosity sections below the POWC. Nutech model estimates for these two fluid-rich intervals indicated net oil pay as high as 95 percent; however, test results showed minimal or no oil recovery. Based on this analysis, there is no indication that the S_o is as high as estimated by the Nutech models; therefore, using the Nutech models to estimate S_o in lower-quality reservoirs would lead to more inaccurate estimations.

II. Evidence for Communication Between the Grayburg Reservoir and Goodnight's San Andres Water Disposal Zone

Water injected into the deeper San Andres Aquifer is separated from the overlying producing Grayburg Reservoir and any potential ROZ by numerous vertical fluid permeability barriers. The source of water from producing wells is likely from water that moved into the producing reservoir from downdip wet intervals prior to Goodnight's water injection.

The implication of vertical communication transecting the Grayburg Reservoir and the San Andres Aquifer is not supported by documented geologic studies in the EMSU. The descriptions and data in the 1939 Anderson analysis, a 1998 Society of Petroleum Engineers (SPE) paper (Love, et al., 1998), the 1983 Technical Committee Report, the Lindsay 1991 core fracture study, and Lindsay 2018 model all support vertical and lateral isolation within the producing Grayburg Reservoir. The studies indicate water encroachment from the downdip water leg of the Grayburg Reservoir and do not provide any direct data or evidence to support a conclusion that faults or fractures transect the Grayburg Reservoir. Additionally, the studies do not indicate any stratigraphic connection to the underlying San Andres Aquifer in the EMSU. Significant horizontal stratigraphic layers, composed of para sequences, act as partial or substantial permeability barriers to vertical fluid movement within the EMSU, as documented in multiple papers by Lindsay (2014, 2018). In Lindsay's 2018 Hybrid Model of Dolomitization, Permian Basin paper, a field-scale meteoric recharge occurring horizontally along vertically compartmentalized para sequences is illustrated, which Lindsey groups into six main reservoir zones within the EMSU Grayburg Reservoir, as shown in Figure 5. Each of these horizontal para sequences is a potential barrier to vertical fluid movement.

Another possibility for vertical permeability, as inferred by Empire's witness, Joseph McShane, is the potential for communication caused by large, continuous open faults or a series of open fracture networks that cut across the permeability barriers in the Grayburg Reservoir. Faulting occurs when rock fractures and either side is displaced vertically or laterally; any significant faulting should be evident as disruptions in the structure contours. However, a review of current structure maps shows that no faults are interpreted across the EMSU in the Grayburg Reservoir or the San Andres Aquifer intervals. Fracture networks, while lacking significant vertical displacement, can still serve as pathways for fluid migration. Indications of fractures are noted in core descriptions for the RR Bell 4, EMSU 649, and EMSU 679 wells. The RR Bell 4 and EMSU 649 wells documented fractures in the foot-to-foot core description, with no indications of size, orientation, length, or whether they are open, closed, or mineralized. The EMSU 679 well had a fracture study (Lindsay, 1991) that detailed the size, scale frequency, and orientation of fractures. The study stated that "most fractures are small, discontinuous vertical fractures, with lengths of 1 to 3 inches" and "A few intervals contain longer, more continuous vertical fractures, with lengths of 1 to 3 feet." Three intervals of collapsed breccia along bedding planes, with small fractures extending only a few inches, are also identified in this report. Although these fractures and collapsed breccias are present in the EMSU 679 well, they do not indicate a continuous vertical fluid migration pathway that would extend into the deeper disposal interval of the San Andres Aquifer and there is no indication that this well is in communication with the San Andres Aquifer.

Additionally, the Monitoring, Reporting, and Verification Plan reports for the North Hobbs Unit and Seminole Field found no indications of faults or fractures within the field's boundaries that transect the Grayburg Reservoir and San Andres Aquifer. The report acknowledged deep-seated faults in formations thousands of feet below the San Andres Aquifer, but this faulting has not been shown to intersect the San Andres Aquifer or create potential leakage pathways for carbon dioxide, which has been injected into the reservoirs since the early 2000's. While these two

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fields are a significant distance apart and contain isolated accumulations, they do represent a regional structural pattern on the CBP. Like the EMSU, Hobbs and Seminole Fields are located on the CBP and could serve as a reasonable analogy for the lack of communication that deep-seated faults have between the San Andres Aquifer and the overlying Grayburg Reservoir in the EMSU.

Love (1998) states "The sets of para sequences stack to form six recognizable zones based on correlations of relatively thin (appox. 20 to 10 feet thick) generally impermeable sandstones". Fractures identified in the evaluated area isolate the upper two zones (Zone 1 and 2) in the Grayburg Reservoir. The zones shown in Figure 5 for the Grayburg Reservior are described as follows: "Zones 1, 2 and 3 are very clean dolomites (floodable reserves, solution gas drive). The top of Zone 1 is the top of Grayburg Reservoir. Generally, Zone 1 has been processed by waterflooding. It is tight to the northeastern half of the field and because of this, it is more brittle and tends to be more fractured than the rest of the Grayburg section. The lower half of Zones 1 and 2 have the most high permeability streaks (solution enhanced grainstones typically 18 inches to 4 feet thick) and tend to have edge water drive connected to the Grayburg shoal along the southwest of the field. Zone 4 is a clastic rich (silty/sandy) and forms a pressure barrier. It is vertically impermeable and can have good porosity zones. This zone has a karsted surface in its upper portion. Zone 5 is typically water drive (3 to 20 percent oil cut) and Zone 6 overlies the top of the San Andres and contains an unconformity in its upper part. There are oil shows well down into the San Andres." Although oil staining and fluorescence are present, these shows of oil are not indications of any likely economic oil recovery targets based on the POWC. The evaluated conformance area shows fractures that were isolated to the upper two zones (Zones 1 and 2) of the Grayburg Reservoir. The presence of these fractures is contained within these individual zones. Three important distinctions made in this detailed analysis of the Grayburg Reservoir are: Zone 4 acts as a pressure permeability barrier; Zones 1, 2, and 3 are primarily pressure depletion drive; and Zones 5 and 6 are primarily water drive with high water cuts. In March of 2000, Love testified that the full-field simulation model and injection and production allocation analysis of Chevron Corporation (Chevron) confirmed that all water production at the crest of the structure was accounted for, with no evidence of extraneous water influx into the area of the EMSU (OCD Case 12,320). Vertical isolation across the Grayburg Reservoir zones is supported by the presence of distinct depletion and water drive mechanisms within the Grayburg Reservoir, as well as the absence of extraneous water influx into the EMSU.

The 1939 Anderson analysis water encroachment map (Figure 6) shows early edge-water movement in the field from the southwest, southeast, and northeast, as well as deeper horizons dipping below the oil-water contact within the field boundaries. Zone A, which correlates with Zones 5 and 6, indicates water contacts well within the EMSU boundaries in 1939. The 1981 water production maps (Figure 7) from the proposed 1983 EMSU committee report show higher water volumes in some areas and a field-wide water cut of 80 percent. Mr. McShane and another of Empire's witnesses, William West, suggest that the few wells producing higher water volumes indicate fracture communication with the San Andres Aquifer. According to the 1981 water production map, 12 of the 200 active wells in the mapped area produced higher barrels of water per day. The small number of wells with higher-than-average water production suggests this may be a well location or an individual well completion issue rather than a reservoir issue. Most of these wells are in the southwest, downdip portion of the field, close to the water contact in the Grayburg Reservoir. This area also shows higher oil production rates relative to the rest of the field because it is supported by an edge-water drive. The 1998 SPE paper (Love, et al., 1998) also shows both the downdip edge-water drive interpretation and poor conformance at the crest of the structure, further indicating a lack of vertical communication within the Grayburg Reservoir.

The EMSU 239 well is the highest structurally positioned well with the highest water rates. It was implied from questioning that this well's data could support fracture communication between the San Andres Aquifer and the EMSU productive interval. The EMSU 239 well was dual-completed in the overlying Queen Reservoir as a gas well and in the Grayburg Reservoir from 3,818 to 3,870 ft measured depth (MD) (-228 to -280 ft TVDSS). It initially flowed 108 barrels of oil (BO) and no water in 1936, pumped 40 BO and no water in 1955, and pumped 26 BO and no water in 1959. The EMSU 239 well was acidized immediately after the 1959 pump test and subsequently tested 20 BO, 10 barrels of water, and 374 thousands of cubic ft of gas. These volumes suggest that this zone was depleted from its original reservoir conditions. In December of 1972, the well was drilled to a new total depth of 3,946 ft MD (-356 ft TVDSS) below the original POWC, and it was perforated and put back on production in July of 1973. No tests are present in the state well files after the 1972 completion. The lower part of the well penetrates Zone 6 from 3,820 to 3,946 ft MD (-230 to -356 ft TVDSS), which is below the estimated field water contact at -350 ft TVDSS. The next available production data are from the 1981 EMSU proposal maps, which showed in excess of 300 barrels of water per day. It is reasonable to assume that this water is coming from the section of the well below the POWC or from edge-water drive in the deeper stratigraphic section of the deeper intervals. Since the initial completion interval had been depleted, declining from a rate of 108 barrels of oil per day (BOPD) in 1936 to 20 BOPD in 1959, and the deeper completion of Zones 5 and 6 produced significant volumes of water in 1981, this further indicates that the upper oil-producing zones within this well are vertically isolated from the lower water-drive zones. The lower part of the well penetrates Zones 5 and 6 at -230 to -358 ft TVDSS, which is below the estimated field water contact. Additionally, the water movement from the southeast, downdip flank of the field, reported as early as 1937, further supports the conclusion that the water produced in the EMSU 239 well originates from Grayburg Reservoir Zones 5 and 6, rather than from the deeper San Andres Aquifer.

The separation between the Goodnight injection interval and the EMSU production interval is further demonstrated by differences in shut-in tubing pressures observed in both EMSU production wells and Goodnight injection wells, as shown in Preston MacGuire's direct testimony Exhibits B-21, B-22, B-23, and B-24 for Goodnight. Additionally, lost circulation zones encountered below the EMSU in the Goodnight injection wells, along with Chevron's decision to use the lower San Andres Aquifer as a water supply source for the EMSU waterflood, further support this separation.

Historical documentation, geologic composition, and current completion, production, and pressure data do not indicate vertical communication within the Grayburg Reservoir. Permeability barriers within and below the Grayburg Reservoir, the absence of extraneous water influx, distinct drive mechanisms within the Grayburg Reservoir, and pressure differences between the EMSU production interval and the Goodnight injection interval, along with the vertical thickness separating the Grayburg Reservoir from the San Andres Aquifer, further confirm that these two reservoirs are separate and isolated, with no practical communication between them.

III. Evidence for Analogy Fields for the EMSU

Fields and units outside the EMSU are often referenced as analogous to Grayburg Reservoir and San Andres Aquifer production within the EMSU. However, many of these fields exhibit unique local stratigraphic variability, structural development and timing, or are geographically isolated. As a result, they have limited or no relevance to S_o or potential production within the EMSU.

The Grayburg Reservoir and San Andres Aquifer are characterized by depositional environments, structural configurations, porosity, permeability, and depths, that can generally be found across the Permian Basin. However, using any specific field as an analogy requires a detailed review of engineering and geologic data to verify the reasonableness of the characteristics being used.

Geographically isolated oil accumulations are designated by different field names to define unique hydrocarbon accumulations. Some fields are further subdivided with additional regulatory rules based on their unique characteristics. A field's fluid saturation, created by postdepositional fluid migration, can be very localized and is therefore a more variable characteristic when applying analogous data. As a result, geographically, stratigraphically, or structurally isolated accumulations outside the EMSU have limited relevance to the S_o within the EMSU.

Several fields have been referenced in my review of Empire's witness testimony, exhibits, and depositions as potential analogies to the EMSU. Lovington, Maljamar, and Vacuum Fields are located on the northwest shelf of the Delaware Basin, as shown in Figure 8. While these fields have similar stratigraphy and depositional characteristics, they are about 75 miles away and structurally and geographically isolated from the CBP by the San Simon Channel. Consequently, they have limited to no relevance to the S_o within the EMSU.

The EMSU is a unit in Eunice Monument Field, regionally located on the northwestern edge of the CBP. The EMSU is composed of the producing Grayburg Reservoir and the underlying San Andres Aquifer. Nearby oil accumulations on the CBP include the Arrowhead Grayburg Unit in Eunice Field; the East Hobbs, North Hobbs, and South Hobbs Units in Hobbs Field; the EMSU B and North Monument Unit in Eunice Monument Field; Tall Cotton Field; and Seminole Field (Figure 8). North of Eunice Monument Field, Hobbs Field is perforated in the Lower Grayburg Reservoir and Upper San Andres Reservoir. Southeast of Eunice Monument Field, Eunice Field also has perforations predominantly below the Grayburg Reservoir. The three units in Eunice Monument Field are primarily perforated within and above the Grayburg Reservoir, extending into the overlying gas-producing Penrose Reservoir. Figure 9 shows a south-to-north diagram with the relative position of the Grayburg Reservoir and perforated intervals in each unit, based on state records. For each wellbore, the black segments represent the Grayburg Reservoir and the colored segments represent the well's perforated interval. Figure 10 shows a west-to-east diagram with the varying depths of the perforations relative to the Grayburg Reservoir across the EMSU, East Hobbs and South Hobbs Units, and Seminole and Tall Cotton Fields. Eunice Field and the North Hobbs and South Hobbs Units have perforated intervals in both the Lower Grayburg Reservoir and Upper San Andres Aquifer but are geographically isolated from Eunice Monument Field. The East Hobbs Unit and Seminole and Tall Cotton Fields produce from deeper stratigraphic intervals within the San Andres Aquifer. These reservoirs are geographically, stratigraphically, and structurally isolated from the EMSU and have no relevance to the S_o within the EMSU. These diagrams show that only the EMSU, EMSU B, and North Monument Unit primarily produce from the Grayburg Reservoir. The North Monument Unit 5-22 is a cored well that was referenced by Mr. West as an analogy for EMSU saturations. This core point in the northern portion of Eunice Monument Field is approximately 8 miles north of the EMSU, and there are approximately 700 wells between them (Figure 11). Given the distance and the numerous wells between the North Monument Unit 5-22 well and the EMSU, data from this core should have little to no relevance to S_o within the EMSU.

DISCLAIMER

This report summarizes my analysis and opinions to date. I reserve the right to amend or supplement this report, if necessary, should additional information become available to me, and to rebut any related opinions reached by experts related to these cases. All the opinions and conclusions herein are rendered to a reasonable degree of professional certainty.

I affirm under penalty of perjury under the laws of the State of New Mexico that the foregoing statements are true and correct. I understand that this self-affirmed statement will be used as written testimony in this case. This statement is made on the date next to my signature below.

Sincerely,

William J. Knights, P.G. 1532
Vice President

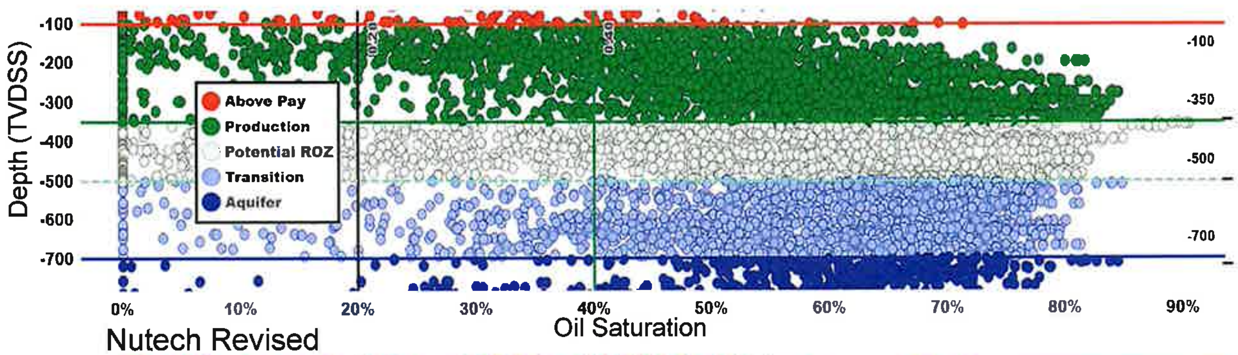
Date Signed: February 6, 2025

WJK:LMS

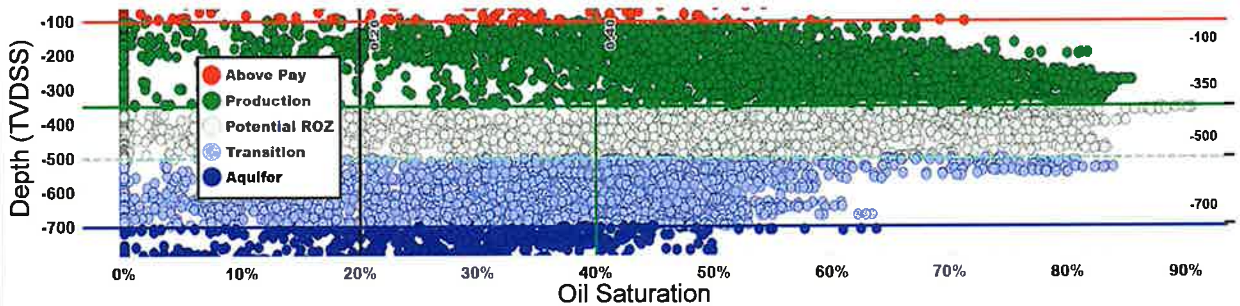
NETHERLAND, SEWELL & ASSOCIATES, INC.

Oil Saturations and Net Pay by Depth
Nutech versus NSAI Conventional Cutoffs

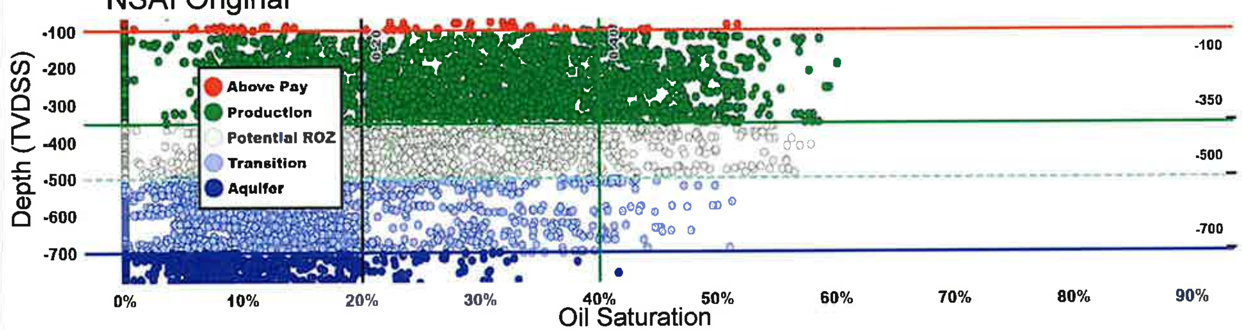
Nutech Original



Nutech Revised



NSAI Original

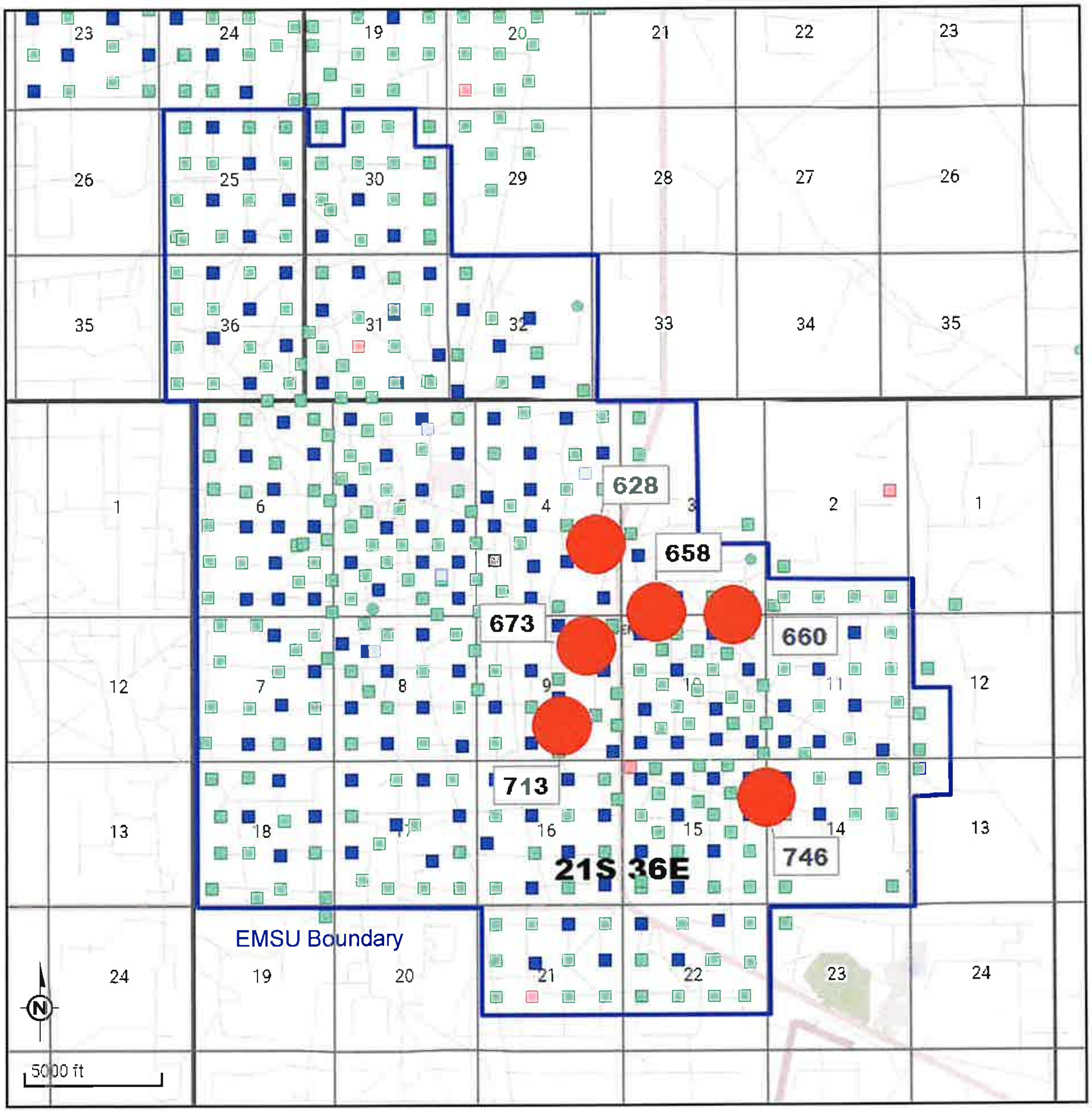


	Net Oil Pay (ft)	Net Wet Thickness (ft)	Net Oil Pay (%)
Nutech Original	924	420	69
	529	277	66
	881	113	89
	542	597	48
Nutech Revised	919	426	68
	390	416	48
	337	657	34
	55	1,084	5
NSAI Original	238	1,106	18
	64	741	8
	13	981	1
	1	1,138	<1

Figure 1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.



Eunice Monument Field
Lea County, New Mexico

Petrophysical Well Locations
Eunice Monument South Unit

SCALE IN FEET
0 2,500 5,000 7,500 10,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

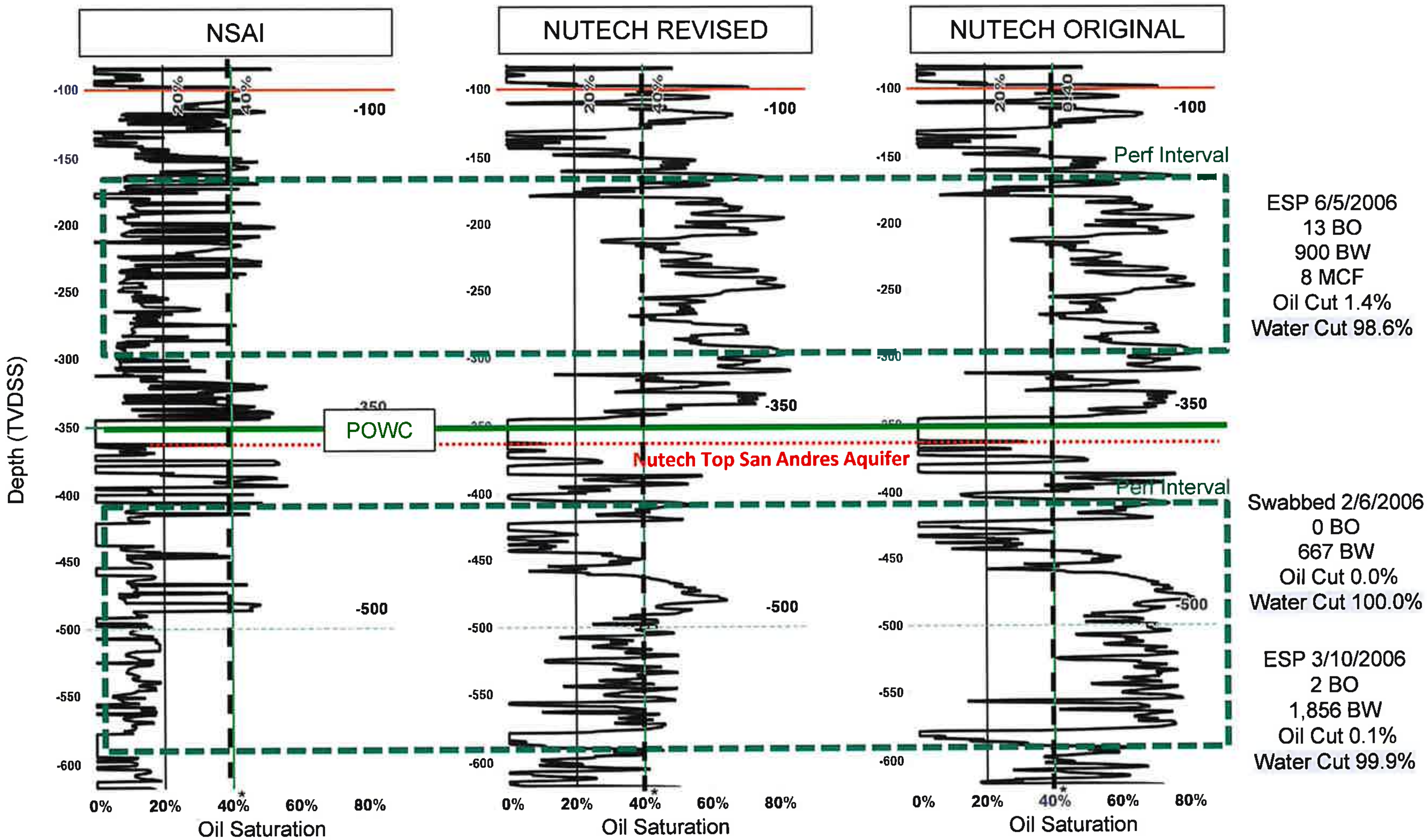
EMSU 658 and EMSU 660 Net Pay and Production Test Summary
Nutech versus NSAI Conventional Cutoffs

Well	Depth	Analysis	Net Oil Pay (ft)	Net Wet Thickness (ft)	Net Oil Pay (%)	Production Test
EMSU 658	Above POWC	Original Nutech	107	15	88	ESP 6/5/2006 13 BO; 900 BW; 8 MCF Oil Cut 1.4% Water Cut 98.6%
		Revised Nutech	107	15	88	
		NSAI	20	102	16	
	Nutech Top San Andres Aquifer					
	Potential ROZ	Original Nutech	71	4	95	Swabbed 2/6/2006 0 BO; 667 BW Oil Cut 0.0% Water Cut 100.0% ESP 3/10/2006 2 BO; 1,856 BW Oil Cut 0.1% Water Cut 99.9%
		Revised Nutech	43	33	57	
		NSAI	9	67	12	
	Below -500 ft TVDSS	Original Nutech	74	1	99	
		Revised Nutech	23	53	30	
		NSAI	0	75	0	
EMSU 660	Above POWC	Original Nutech	123	7	95	Pump 3/10/2006 11 BO; 158 BW; 5 MCF Oil Cut 6.9% Water Cut 93.1%
		Revised Nutech	123	7	95	
		NSAI	16	114	12	
	Nutech Top San Andres Aquifer					
	Potential ROZ	Original Nutech	-	-	-	Interval Not Tested
		Revised Nutech	-	-	-	
		NSAI	-	-	-	
	Below -500 ft TVDSS	Original Nutech	13	2	86	Pump 12/30/2005 7 BO; 4,056 BW Oil Cut 0.2% Water Cut 99.8%
		Revised Nutech	2	13	14	
		NSAI	1	14	7	

Figure 3

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Oil Saturation Profiles
Eunice Monument South Unit
Lea County, New Mexico
EMSU 658



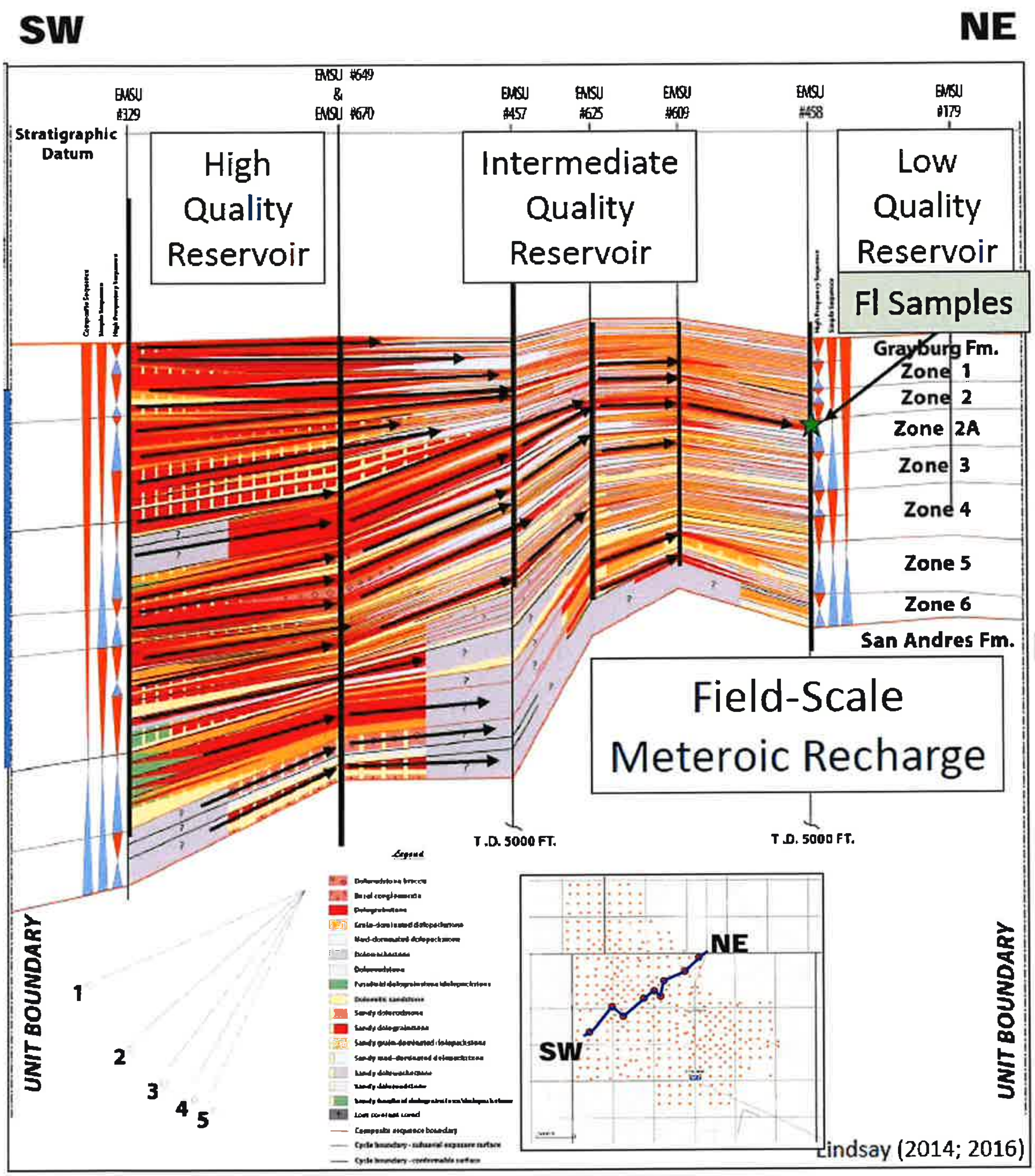
*Conventional net oil pay cutoffs are above 40 percent oil saturation.

Figure 4

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Stratigraphic Cross Section with Meteoric Recharge
Grayburg Reservoir
Eunice Monument South Unit
Lea County, New Mexico

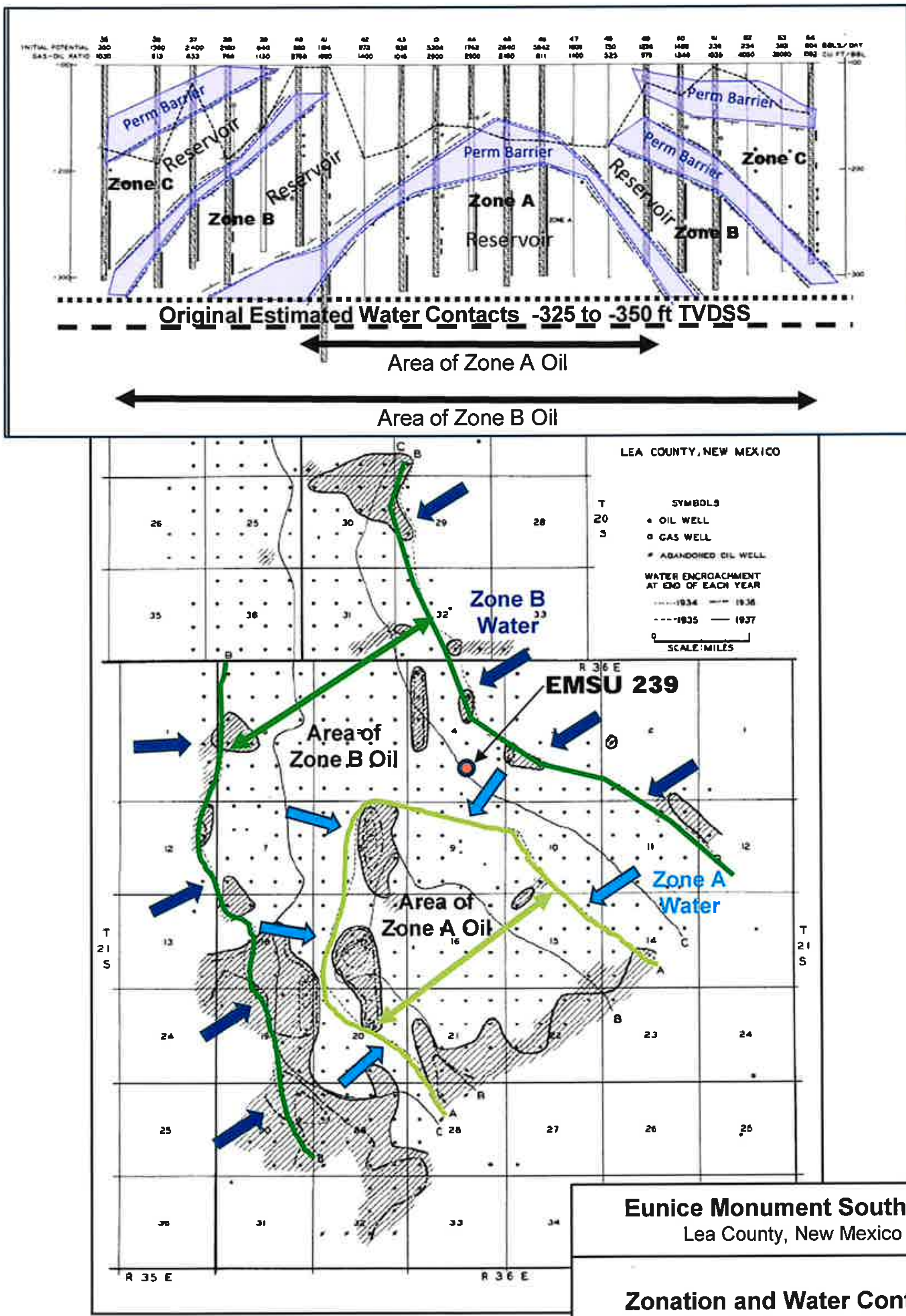


Adapted from Lindsey, Robert, F., May 2018, Hybrid Dolomitization Permian Basin, AAPG ACE Salt Lake City Presentation.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Eunice Monument South Unit
Lea County, New Mexico

Zonation and Water Contacts Grayburg Reservoir

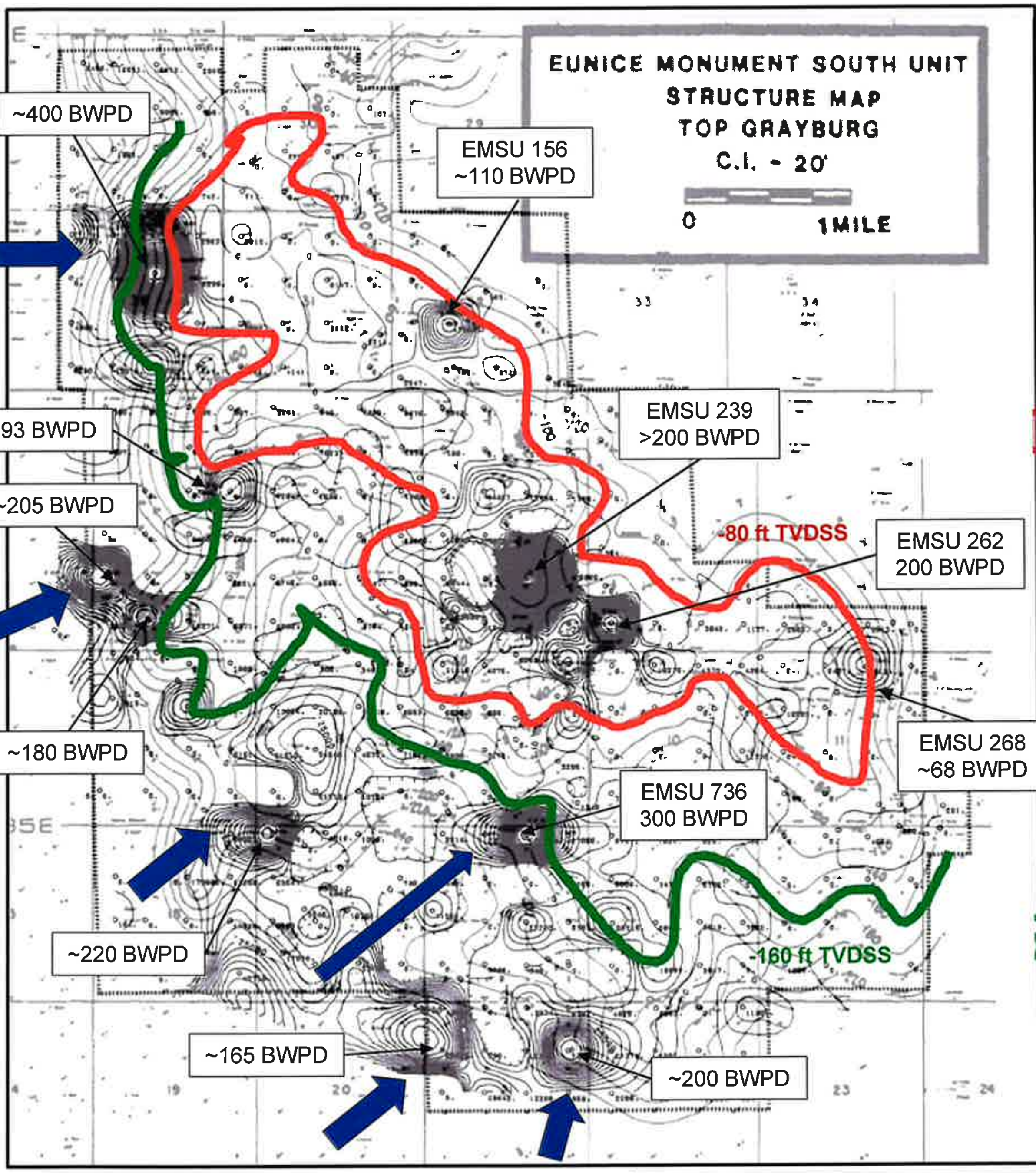
SCALE IN MILES
0 0.5 1 1.5 2

Adapted from Anderson C.C. etal, 1939, Report of Investigations USDOI-Bureau of Mines, Reservoir Characteristics of the Eunice Oil Field, Lea County, New Mexico.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Eunice Monument South Unit
Lea County, New Mexico

1981 Water Production and Top Grayburg Structure

SCALE IN MILES
0 0.5 1 1.5 2

Adapted from Proposed Eunice Monument South Unit Lea County, New Mexico, Technical Committee Report, April 1983, 08397_4269.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 7

NETHERLAND, SEWELL & ASSOCIATES, INC.

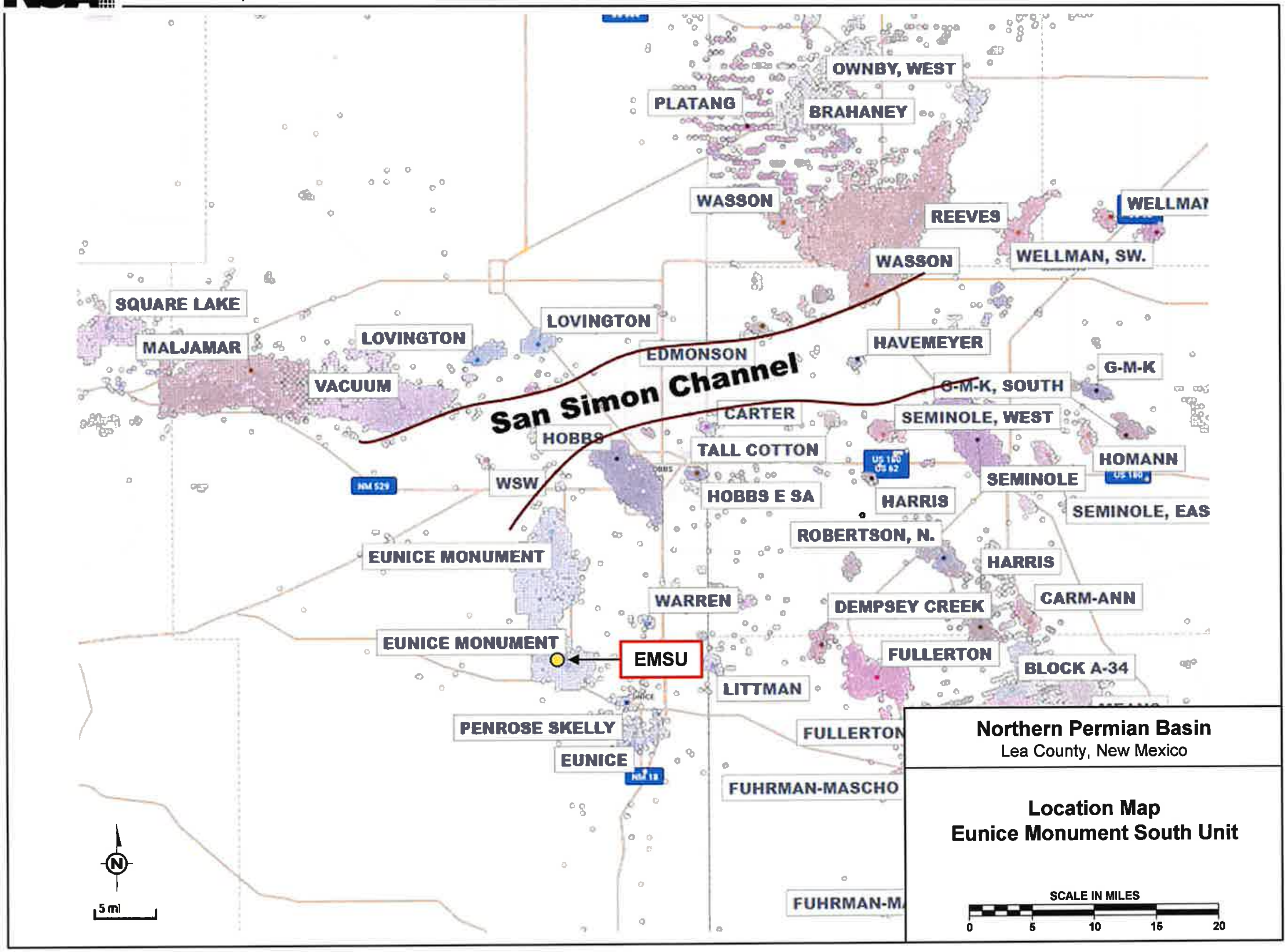


Figure 8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

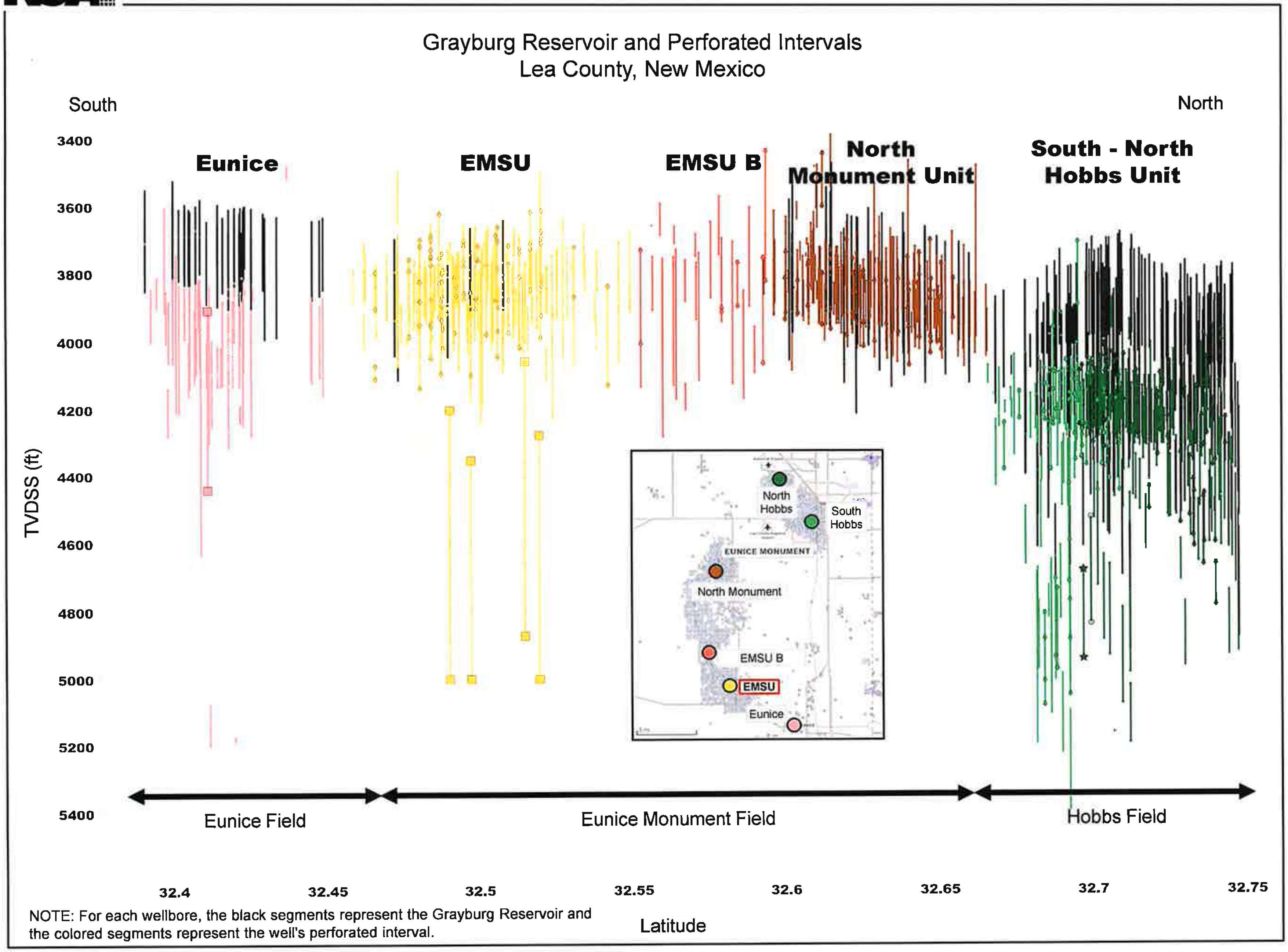
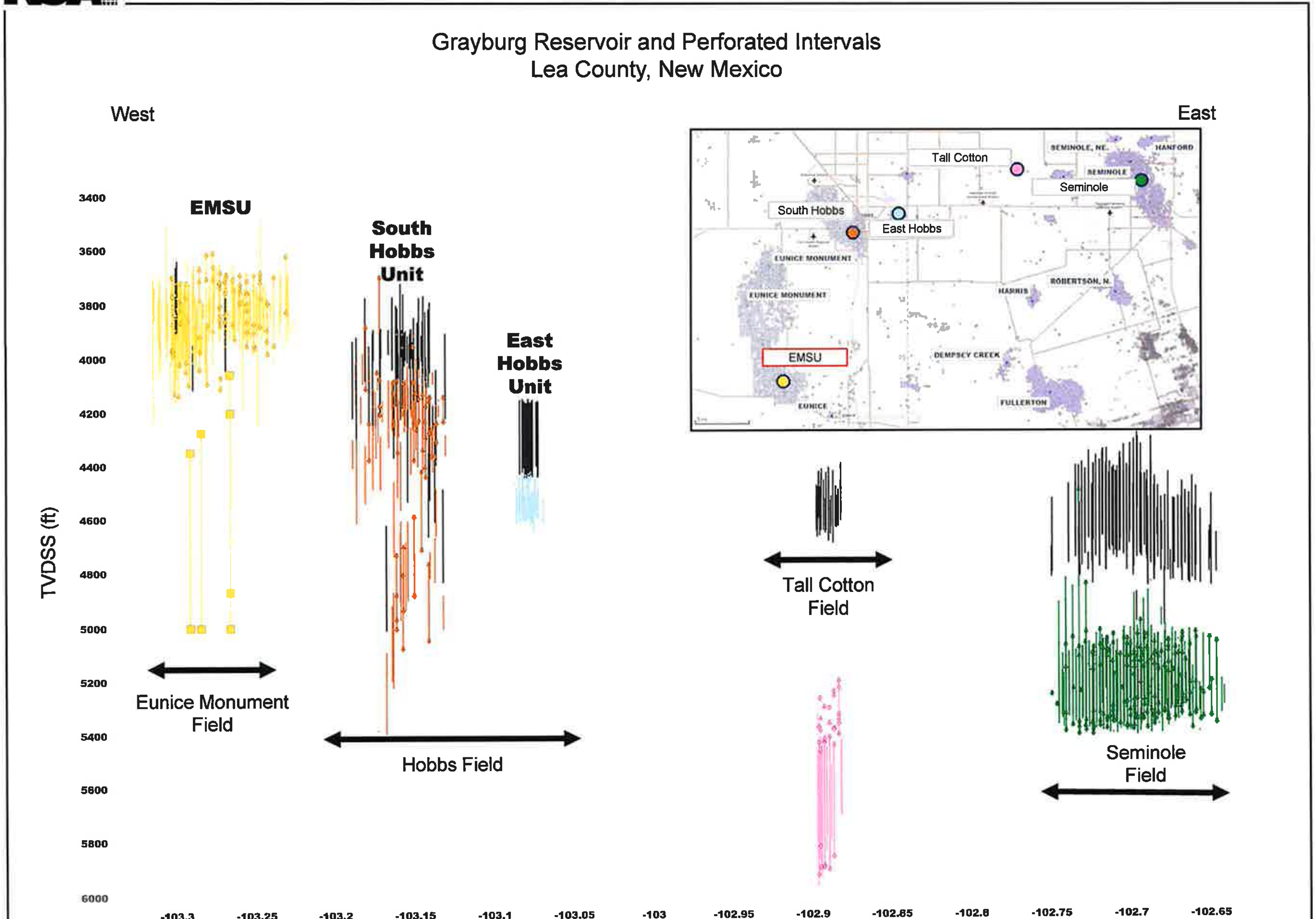


Figure 9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

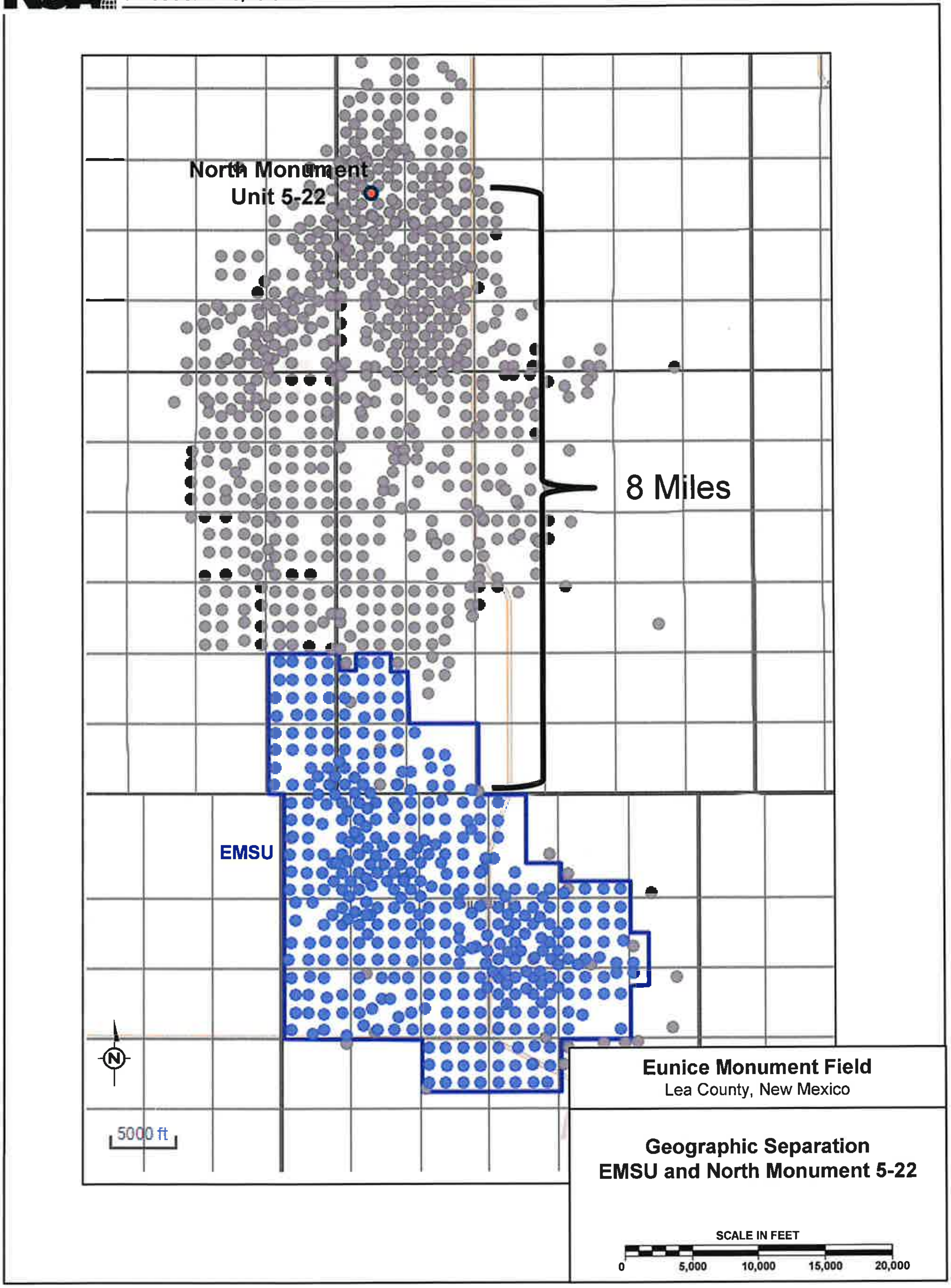


NOTE: For each wellbore, the black segments represent the Grayburg Reservoir, and the colored segments represent the well's perforated interval.

Figure 10

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 11

APPENDIX A - BIBLIOGRAPHY

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Tracy G. Love, Examiner Hearing, Case No 12320, State of New Mexico Energy, Minerals and Natural Resources Department Oil Conservation Division, March 2, 2000.

NETHERLAND, SEWELL & ASSOCIATES, INC.

APPENDIX B - ABBREVIATIONS

%	percent
BO	barrels of oil
BOPD	barrels of oil per day
BW	barrels of water
BWPD	barrels of water per day
CBP	Central Basin Platform
Chevron	Chevron Corporation
Empire	Empire Petroleum Corporation
EMSU	Eunice Monument South Unit
ESP	electrical submersible pump
ft	feet
Goodnight	Goodnight Midstream Permian, LLC
MCF	thousands of cubic feet
MD	measured depth
NSAI	Netherland, Sewell & Associates, Inc.
Nutech	NuTech Energy Alliance Ltd
OIP	oil-in-place
POWC	producing oil-water contact
ROZ	residual oil zones
S_o	oil saturation
SPE	Society of Petroleum Engineers
TVDSS	true vertical depth subsea

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

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS, LEA COUNTY, NEW MEXICO

CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24020, 24025

APPLICATION OF GOODNIGHT PERMIAN MIDSTREAM, LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO

DIVISION CASE NO. 22626
ORDER NO. R-22869-A
COMMISSION CASE NO. 24123

<u>SELF-AFFIRMED REBUTTAL STATEMENT OF JOHN C. MCBEATH, P.E.</u>

1. My name is John C. McBeath, P.E. I am a consulting petroleum engineer and founding partner of Austin Consulting Petroleum Engineers Inc ("ACPE"), a petroleum engineering consulting firm located in Austin, Texas. ACPE provides a wide range of petroleum engineering services to oil and gas stakeholders from large corporations to individuals, including for example reservoir engineering studies, economic evaluations, regulatory consulting, reserve

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. F
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

determination, fair market value analysis, reservoir simulation, log analysis and operational investigations.

2. I provided direct written testimony in these cases that was finalized on August 23, 2024, and filed with the Commission on August 26, 2024, in a document entitled **SELF-AFFIRMED STATEMENT OF JOHN C. MCBEATH, P.E.** That statement included **Goodnight Exhibit F-1,** a copy of my curriculum vitae, which is incorporated herein by reference. I believe my credentials, my experience and my analyses and review of the information in this matter qualify me to testify as an expert in petroleum and reservoir engineering.

3. I have been asked to review the available data and information relating to the applications filed by Goodnight Midstream ("GM") in these cases. I have conducted a study of this information and this, along with my experience, forms the basis of my opinions expressed herein. This rebuttal statement contains additional responses to the testimony of certain Empire witnesses. If any additional testimony, clarification or information relating to Empire's witness statements becomes available, I reserve the right to respond. All the opinions and conclusions I provide in this statement are rendered to a reasonable degree of engineering certainty.

4. In my direct written testimony, I was asked to evaluate and provide testimony on (1) general requirements for undertaking residual oil enhanced recovery projects; (2) evaluating and assessing Empire's plans to conduct a residual oil zone ("ROZ") enhanced recovery project in the San Andres within the Eunice Monument South Unit ("EMSU"); (3) assess the economic feasibility of Empire's proposed ROZ project in the San Andres; and (4) to evaluate and assess potential impacts from injection of produced water in the San Andres on EMSU operations.

5. For purposes of this rebuttal statement, I have been asked to review and respond to (1) Mr. William West's testimony regarding his analyses of Goodnight's injection influence,

economic models for ROZ development, formation pressures and related calculations and assumptions; (2) Dr. James Buchwalter's testimony regarding his reservoir simulation model, assumptions, inputs, and results; and (3) to respond to Empire's witness testimony regarding Empire's ROZ evaluation and plans, the economic feasibility of ROZ development in the EMSU, and alleged impacts to EMSU operations.

6. I have considered the following data and information in forming my opinions:

a. Data and information produced by GM in this matter.

b. Data and information produced by Empire in this matter.

c. Well data obtained from the NMOCD website.

d. Well logs obtained from the NMOCD website.

e. Well data obtained from subscription service Enverus and S&P Global.

f. Previously filed testimony of both Empire's and GM's witnesses provided by Attorneys.

g. Discussions with GM personnel.

h. Discussions with Netherland Sewell & Associates ("NSAI").

i. August, 2024 testimonies of GM's witnesses.

j. August, 2024 testimonies of Empire's witnesses.

k. Depositions in the above styled cases.

l. Additional data and information provided by Empire witnesses.

Summary of Opinions

1. Mr. William West's economic calculations relating to assumed 72-pattern and 250-pattern ROZ project in the San Andres formation at EMSU are based on unsupported and unreliable input parameters that render the inflated and overly optimistic results unreliable.

2. Examples of these unreliable inputs include an assumed 400 feet of 30% oil saturation in the San Andres, oil prices that exceed $115/bbl, mutually inconsistent dimensionless oil and CO2 curves that have not been shown to be applicable or appropriate for the San Andres at EMSU, and unsupported CO2 purchase prices assuming 45Q tax credits.

3. Correcting Mr. West's economic calculations with reasonable inputs for oil saturation, oil prices and CO2 prices results in both the 72-pattern and 250-pattern projects having large negative net present values.

4. Empire's recent and current financial condition makes it highly suspect that they could self-finance the enormous capital and other expenses required under West's assumed project costs and implementation schedule. Outside financing or project partnership would require much more detailed study and analyses of the proposed projects.

5. Mr. West's opinion that the San Andres was pressure depleted by April 1986 is based on uncertain data and questionable assumptions.

6. The repeat formation tester ("RFT") run in the EMSU 211 well shows formations that are not in pressure communication. The RFT measurements show formations that can sustain large pressure differences over relatively small depth changes meaning that the intervening formations provide hydraulic isolation.

7. Whether Mr. West chooses to use an original reservoir pressure datum of +250 MSL or -250 MSL doesn't change the fact that uncertainty exists over initial reservoir pressure assumptions, and early data is limited for both the Grayburg and San Andres formations at EMSU.

8. Dr. Buchwalter's reservoir model is relatively simple and homogeneous compared to historical descriptions of the reservoir characteristics and documented geologic features of the EMSU and surrounding areas. This means his model does not reflect the known reservoir complexities necessary to accurately model fluid movement.

9. Dr. Buchwalter did not incorporate well completion histories that include plugging back, deepening or recompleting wells. These operations occurred on hundreds of wells but were not used in the model.

10. Dr. Buchwalter did not provide well level pressure histories matches and field-wide matches are based on few data points.

11. Dr. Buchwalter's model does not allow a connection to the Grayburg edge water sources recognized by previous operators and Empire's witness Dr. Lindsay.

12. The model prevents water movement within the Grayburg with an unusually high immobile water saturation.

13. Dr. Buchwalter modified individual model cells to allow a connection between the Grayburg and the San Andres in certain wells.

14. Dr. Buchwalter's model allows only one possible source of water (the San Andres) for certain high water production wells. His conclusion that the water in certain EMSU wells came from the San Andres was presupposed by the model construction and based on the differences between the model and reality. This conclusion cannot be extended to the actual wells and formations.

Response to Self-Affirmed Statement and testimony of Mr. William West

West's 72 and 250 Pattern CO2 Economic Calculations

7. A few days before the August 2024 deadline for pre-filing testimony, Empire produced a spreadsheet that purported to calculate the economics of a 72-pattern San Andres ROZ CO2 flood at the EMSU. This spreadsheet was ultimately sponsored by Empire's witness Mr. William West, along with a similar spreadsheet that evaluated an assumed 250-pattern project. The spreadsheet results are discussed in Mr. West's testimony and portions are presented in his exhibits I-26 and I-27.

8. Mr. West asserts that based on his calculations, a 72-pattern continuous CO2 injection San Andres flood at EMSU could generate $3.2 billion in oil revenue and a 10% discounted net present value of $263.3 million. Total assumed capital expenses under the 72-pattern plan (approximately 2,880 acres at 40-acre pattern spacing) are $350 million and the project is cumulatively cash flow negative for 8.5 years. Mr. West also presented a 250-pattern economic spreadsheet that included additional EMSU patterns, 32 EMSU-B patterns and 64 Arrowhead Grayburg Unit (AGU) patterns.[1] This 250-pattern version of the spreadsheet, summarized in West's exhibits I-28 and I-29, allegedly results in $12.8 billion in revenues and a 10% discounted net present value ("NPV10") of $585.6 million. For the 250-pattern plan (covering approximately 10,000 acres in the aggregate at 40-acre pattern spacing) total capital expenses are over $1.2 billion and the project is cumulatively cash flow negative for 12.5 years.

9. There are numerous questionable inputs and assumptions in Mr. West's calculations that are not adequately supported with sufficient back-up or data. Two key dubious assumptions

[1] I am advised that the EMSU-B and AGU unit areas are not part of the upcoming proceeding.

made by Mr. West largely drive the overly optimistic outcome of his calculations, and in my opinion render the resulting economics unreliable. The first is that at the EMSU, EMSU-B and AGU, West assumes 400 feet of 30% oil saturation exists in the San Andres formation. The second assumption is that the dimensionless curve used to mathematically convert hypothetical San Andres CO_2 injection into hypothetical San Andres oil production is reasonable and appropriate for the San Andres formation at the EMSU, EMSU-B and AGU. I discuss each of these assumptions individually in turn below.

10. First, Mr. West assumes that 400 feet of 30% oil saturation exists in the San Andres formation for each pattern in his 72- and 250-pattern spreadsheets. Mr. West provided no discussion or analysis to justify the use of these values, and no other Empire expert sponsored them. These assumed values are used along with 10% porosity and an oil formation volume factor of 1.2 to calculate the hydrocarbon pore volume (HCPV) for a 40-acre pattern as 3,103,200 STB. This exact amount is used for each pattern for both the 72-pattern and 250-pattern spreadsheets. No sensitivity analysis was presented to assess how uncertainty or value ranges to this important variable affects oil recovery and the implicitly related economic viability of the assumed EOR project.

11. In my previous testimony I discussed and summarized the log analysis of NSAI in certain well intervals. I have expanded those summaries here to explore the validity of Mr. West's porosity and oil saturation assumptions. Based on my review of the San Andres intervals from the .las files provided by NSAI for the EMSU 628, EMSU 658, EMSU 660, EMSU 673, EMSU 713, EMSU 746 and the Ryno (Snyder) SWD #1 wells, the average porosity and oil saturations for the top 400 feet of the San Andres aquifer are summarized below:

Well	PHIE	Sw	So
EMSU 628	10.57	88.23	11.77
EMSU 658	9.10	86.22	13.78
EMSU 660	10.32	86.39	13.61
EMSU 673	9.69	87.88	12.12
EMSU 713	7.89	94.03	5.97
EMSU 746	12.26	88.29	11.71
Ryno (Snyder) 1	5.62	96.25	3.75
Average	9.35		10.39

11. The summary above shows that based on NSAI's petrophysical analysis of the San Andres, Mr. West has slightly overestimated the porosity and grossly overestimated the oil saturation by about a factor of three. This means that Mr. West has overestimated the HCPV of each hypothetical pattern which has the effect, under his method, of overestimating oil recovery and therefore revenue. Under the conditions at EMSU, it is unlikely that a CO2 flood could be technically successful at such low oil saturations. It is even more unlikely that a CO2 flood could be economically viable. Empire's experts agree that a 20 percent oil saturation is the cutoff for commercial ROZ development, and they are not aware of any ROZ projects that have targeted intervals with oil saturations below 20 percent. See **Exhibit Goodnight F-21**[2] (Trentham and Lindsay depo. excerpts)

12. The second important assumption in Mr. West's CO2 economic spreadsheet is his dimensionless curve that relates injected CO2 to oil recovery. Mr. West's dimensionless curve is from an SPE paper entitled "Estimates of Potential CO2 Demand for CO2 EOR in Wyoming Basins", authored by S. Wo, L.D. Whitman and J.R. Steidtmann. **Exhibit Goodnight F-22** is a

[2] Exhibit numbering continues sequentially from my August 23, 2024, Self-Affirmed Statement

copy of this SPE paper.[3] The main thrust of this paper is to estimate how much CO2 is needed to flood candidate Wyoming oil fields under both miscible and immiscible conditions. The paper states "The simple formula presented in this paper provide a quick estimation of the required initial and total CO2 volumes with specified reservoir parameters". Empire also provided a presentation by Shaochang Wo that contains much of the same information as the SPE paper. Neither the SPE paper or the related presentation mentions residual oil zones or ROZ. The San Andres formation makes a brief, uncredited appearance (see figure 4 from SPE paper below) for use as a comparison to the Lost Soldier Tensleep project, a Wyoming CO2 project. The paper does not specify the source of the San Andres information on Figure 4, nor does it provide any of the data or information on which the dimensionless curve is based. Without those details, it is not reasonable to assume that dimensionless curve is appropriate for the San Andres in the EMSU.

13. Based on the dates of the presentation and publication of the paper, (2007 and 2009 respectively) and the history of CO2 flooding in the San Andres in West Texas, it is likely that the curve is mostly related to main-pay CO2 projects and is not ROZ specific. Notwithstanding the lack of information regarding the source of this dimensionless curve, it assumes a WAG injection scheme, not continuous CO2 injection as planned in Mr. West's calculations. Taking the x-axis label on Figure 4 at face values (Cumulative WAG (CO2+Water) Injection HCPV) the data used to create this graph incorporated the known recovery benefits of WAG injection, unlike Mr. West's assumptions.

14. Mr. West uses a separate dimensionless curve to predict CO2 production (recovery for recycling) as a function of CO2 injection. The source of this curve is not referenced and neither its validity nor applicability to the EMSU is discussed by Mr. West. Nevertheless, it is used in Mr.

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[3] Exhibit numbering continues sequentially from my August 23, 2024, Self-Affirmed Statement

West's economic spreadsheets to account for produced CO2 that can be recycled, thereby reducing purchased CO2, and keeping the largest source of costs unreasonably low. According to the curve, after one HCPV of CO2 is injected .95 HCPV of CO2 has been produced back, an unusually high amount. According to the oil dimensionless curve, at 1 HCPV of CO2 about 11% HCPV of oil is recovered. What filled the difference between 11% and 5% HCPV when only CO2 was injected? This disagreement between the two dimensionless curves is illogical and demonstrates a fundamental problem with Mr. West's analysis. Notwithstanding each curve's individual problems and the lack of information about their genesis, this is a fundamental disconnect between the two dimensionless curves. Importantly, CO2 purchase is usually the largest operating expense for implementing a CO2 flood and this unsubstantiated CO2 dimensionless curve will reduce CO2 purchase and maximize CO2 recycling. CO2 purchase costs even exceed capital expenses in both Mr. West's 72- and 250-pattern calculations; 72: $472,392,000 (CO2) vs. $350,000,000 (capital) and 250: $1,703,626,000 (CO2) vs. $1,212,750,000 (capital). In summary, applying the CO2 production dimensionless curve in the EMSU is unjustified based on what we know.

15. The use of a dimensionless curve is reasonable, reliable and appropriate only if sufficient study and analysis is conducted to confirm that the data upon which the curve is based is analogous to the characteristics and circumstances of the target formation and producing property. It appears that Mr. West did not do that work but simply assumed it was applicable to an EMSU San Andres CO2 flood in a ROZ.

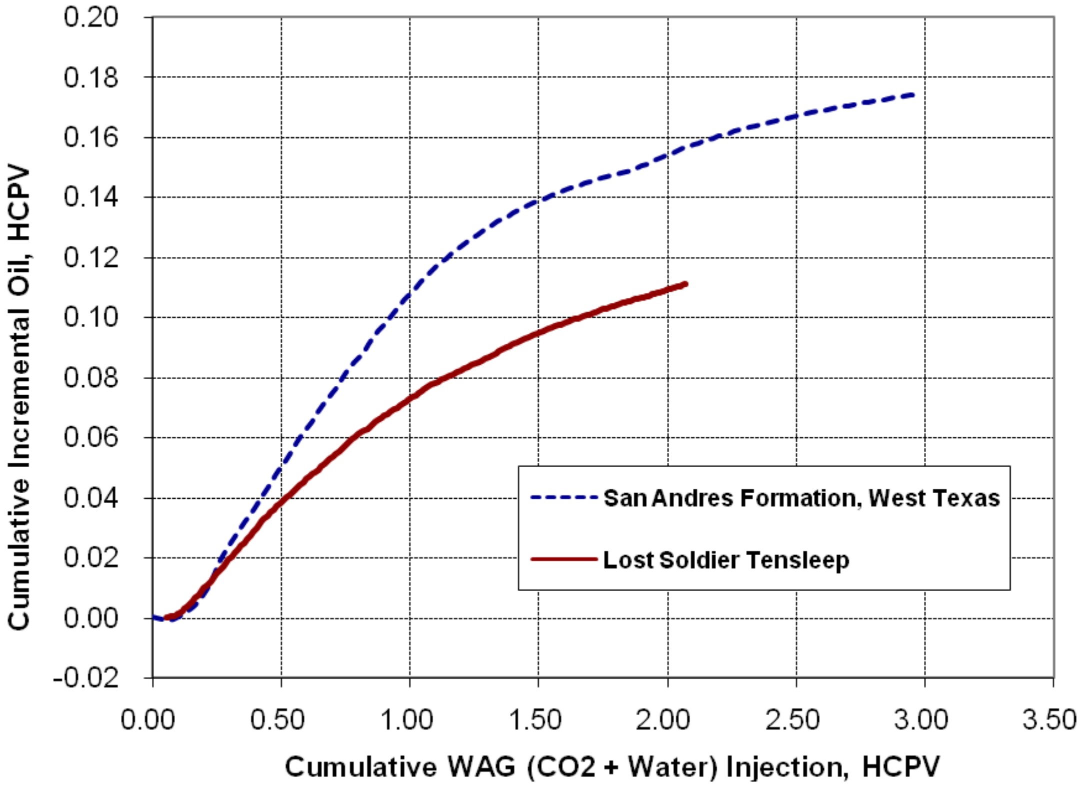


Figure 4. Dimensionless curves of incremental oil versus total WAG injection

Fig. 4 from SPE 122921

16. In addition to these three problematic engineering assumptions, Mr. West's economic analyses are unreasonable for several other important reasons. Mr. West testified that his future revenue calculations are based on an initial oil price of $75/bbl, escalating at 1% per year for future prices.[4] He characterized this price estimate as conservative; however, the final prices in the deck exceed $115/bbl. (West 12-03-24 deposition pages 236-237) **Exhibit Goodnight F-23** contains a comparison of the prices used by Mr. West, a flat price of $75 and a futures price deck based on recent NYMEX reported transactions. In my experience, the

[4] The prices are actually escalated by 1/12% per month in the detailed monthly revenue calculations.

uncertainty of future oil prices requires assessing the project's sensitivity to these prices and incorporating risk for such uncertainty. Mr. West calculations do not incorporate either of these but instead uses optimistic pricing that skews his results.

17. In addition to inflating the price of oil in his model, Mr. West also explained that he used a discounted CO2 price under the assumption that the CO2 supplier could deliver CO2 that qualified for 45Q tax credits and would therefore reduce the delivered price of CO2 to 1.00/mcf. He provided no support for the undiscounted price of $1.50/mcf or for the assumption that the seller could supply CO2 that could qualify for these credits. No contract information or CO2 supplier information was provided by Mr. West as support for the undiscounted or discounted prices. In my opinion, Mr. West's CO2 prices are unsupported and the assumption of a reduced CO2 price is speculative.

18. To demonstrate the impact of the above-mentioned variables on Mr. West's economic calculations, I have corrected his calculations in several ways. The first revisions to Mr. West's calculations incorporate two alternative oil price assumptions: (1) a flat $75/bbl and (2) a future price based on recent NYMEX transactions. Also included in this revision is the incorporation of the average porosity (9.35%) and oil saturation (10.39%) from the NSAI petrophysical analyses in place of the 10% porosity and 30% oil saturation. As discussed above, West provided no calculation or basis for the use of these parameters, in contrast to the values I have substituted which are based on the detailed work of NSAI.

19. With just these input parameters changed, Mr. West's 72-pattern $262.5 million value drops to negative values: -$24 million using a flat $75/bbl oil price and -$84.3 million based on the NYMEX futures oil price. Using the same two oil price assumptions drops Mr. West's 250-pattern value of $585.6 to -$86.5 million and -$215 million.

20. **Additionally, I revised the CO2 price from $1.00/mcf to $1.50/mcf to account for the uncertainty regarding 45Q tax credit-based prices. Depending on the oil price assumption, this revision results in a range of values for the 72-pattern flood of -$66.6 million to -$175.9 million and for the 250-pattern flood from -$127.5 million to -$307 million. Exhibit Goodnight F-24** summarizes the results of my modifications of Mr. West's economic spreadsheets.

21. Capital costs and operating costs are additional inputs to Mr. West's economic analysis that incorporate unknown and potentially unreasonably assumptions. Mr. West provides no basis or support for his capital or operating cost assumptions for either the 72-pattern or the 250-pattern economic models, other than to indicate that they are generally the same as the costs outlined in the Darrell Davis memo. It is difficult to evaluate the reasonableness of West's cost assumptions without a breakdown of what is being included or excluded, and the estimates for each cost category. But it is not even necessary to test different ranges for these costs to show that his economic models are unreasonably optimistic and do not withstand scrutiny. Simply adjusting the input prices for oil and CO2 and the parameters for porosity and oil saturation to more representative values upends his economic projections.

22. **Exhibit Goodnight F-25** is a series of graphs that show the cumulative net cash flow and cumulative discounted net cash flow of Mr. West's 72- and 250- pattern plans along with my revisions to those plans discussed in paragraph 20, above. **Even under the optimistic runs made by Mr. West, Empire would be required to fund projects that went into the red as far as negative $246 million for the 72-pattern plan and negative $346 million for the 250-pattern plan.**

Mr. West's Allegations of San Andres Pressure Depletion

23. In his August 2024 statement, Mr. West included testimony and exhibits that purported to show that the San Andres formation was 18.5% depleted by April 1986, allegedly proving that the Grayburg and San Andres formations were connected. Mr. West's opinion relies on an estimated original reservoir pressure compared to a single RFT measurement. The original reservoir pressure was reported in an exhibit to the EMSU unitization hearing, but the well data or subsurface measurement was not presented. I researched the referenced well and was unable to locate any subsurface pressure measurement to substantiate the reported pressure. Mr. West focused on the deepest EMSU 211 RFT measurement at 4,006 ft. However, the RFT measurements taken as a whole are instructive to assess whether or not there is a connection from deeper formations to shallower formations. The EMSU 211 RFT measurements were:

Depth (ft.)	Pressure (PSI)
3707	364
3749	360
3807	402
3834	544
3852	579
3873	735
3884	997
4006	1245

24. RFTs or similar downhole tools are used to measure the pressure of the formation and to establish how that pressure changes with depth. The pressure gradient within the reservoir allows reservoir engineers to determine what types of fluids exist within the reservoir and at what depths those fluids transition from one type to another. If there is a hydraulic connection between tested zones the pressure changes should exhibit a gradient equal to the fluid within the reservoir.

This phenomenon is used to identify the type of fluid in the reservoir and various fluid contacts such as the gas oil contact (GOC) or the oil water contact (OWC). If gas is the reservoir fluid, a small gradient will be seen by measured pressures changing very little with depth. If oil or water are present in the reservoir, larger pressure gradients will be measured. These gradients are related to the fluid density, for example .3 or .35 psi per foot for oil or .435 or greater for water.

25. In the EMSU 211 RFT pressure measurements, the changes in pressure with depth cannot be explained by a hydrostatic column of fluid within a connected reservoir. For example, the pressure difference between the two deepest measurements is 248 psi (1245 psi -997 psi) over a depth difference of 122 feet (4006 psi - 3884 psi). This is a pressure gradient over 4 times that of water. Similarly, the measurements at 3884 ft and 3873 ft show a pressure difference of 262 psi over 11 feet of depth change, which is a pressure gradient about 55 times that of water. Comparisons between other RFT depths show either similar high gradients or even negative pressure gradients.

26. The RFT pressure measurements do not support Mr. West's contention that the Grayburg and San Andres formations are connected resulting in depletion of the San Andres formation. In my opinion, the pressure readings from the 211 RFT show that the various formations can support large pressure differences and are therefore not connected at all.

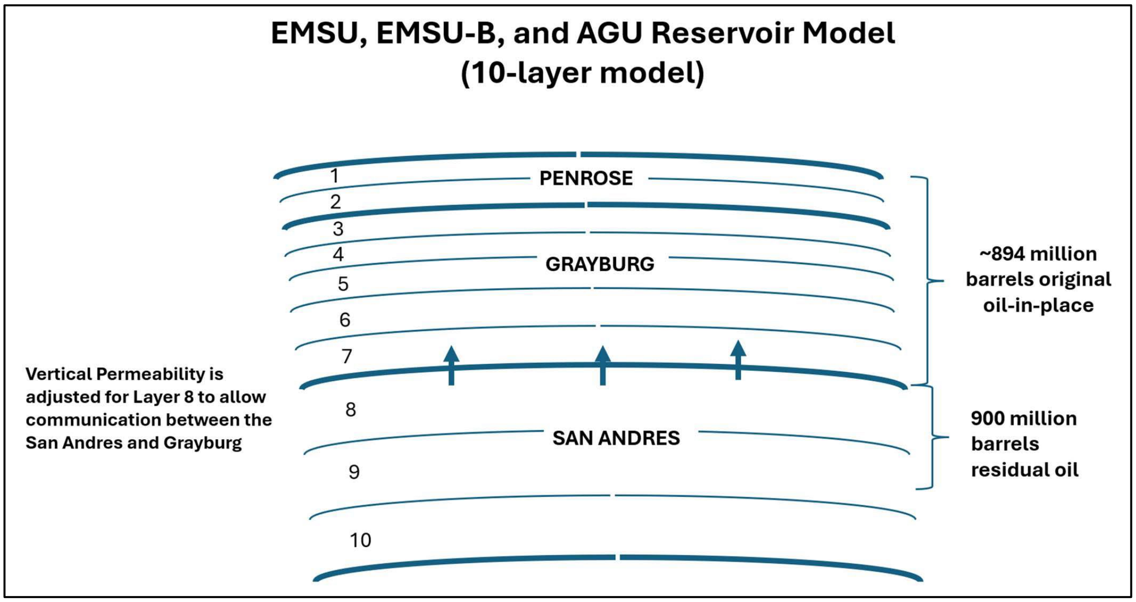
27. I am also aware that there is considerable uncertainty about the original reservoir pressure reported in the EMSU Unitization hearing and used by Mr. West to estimate the reservoir pressure at 4006 ft. in EMSU 211. Mr. West used 1450 psi at -250 ft MSL in his exhibits and testimony from August 2024. He now suggests that the 1450 psi was measured at +250 ft. MSL. This would be an unusual and very shallow datum to use for reporting the original pressure for the Grayburg formation, the main formation discussed in the unitization hearing. A datum of +250

MSL is equivalent to the Seven Rivers formation, which is shallower than the top of the unitized interval at -100 feet MSL or the top of the Grayburg, whichever is shallower. I can think of no reason why Gulf in a hearing largely focused on the Grayburg formation and its potential for waterflood, would choose a datum so far above the subject intervals. The confusion likely stems from the use of the somewhat archaic terminology "s.s." or "sub-sea." The "sub" already indicates that the reported distance is below sea level. Therefore 250 ft. S.S. is equivalent to -250 MSL. I have encountered this situation before when formation top depths are less than the referenced surface elevations, such as kelly bushing (k.b.). A similar pressure and datum were reported in the Arrowhead Grayburg Unitization hearing. **Exhibit Goodnight F-26** contains NMOCD hearing information related to this issue. It makes clear that the relevant data presented, including reservoir pressure, is in reference to the Eunice pool and not the Seven Rivers or Eumont pool, which had already been established at the time of the EMSU hearing.

Response to Self-Affirmed Statement and testimony of Dr. James L. Buchwalter

28. I have reviewed the Self-Affirmed Statement of Dr. James L. Buchwalter along with his back-up data and information he supplied in support of his testimony. I also attended his virtual deposition. Dr. Buchwalter constructed a numerical simulation model including the EMSU, EMSU-B and AGU. The model consists of 350,000 cells and included 10 layers; 2 Penrose, 5 Grayburg and 3 San Andres. Dr. Buchwalter reports that he used production and injection data from 683 wells, including injection volumes from 23 saltwater disposal wells. From the results of his simulation, Dr. Buchwalter makes various conclusions regarding pressures and the movement of reservoir fluids in the past and into the future. The reliability of his conclusions and opinions are directly related to the input data and assumptions used in the model.

29. Except for modest variations in porosity in the Grayburg layers and specific vertical permeability changes in Layer 8 (discussed below), the model is quite homogenous. For example, there is no variation in horizontal permeability within any of the layers. Porosities are constant in Layers 1, 2, 8, 9 & 10. This depiction of EMSU geology is in conflict with the available published studies, public testimony of the previous operator Chevron, and Empire's witness Mr. West.



Buchwalter Exhibit E-2

30. The July 1939 Report of Investigation, United States Deptpartment of the Interior, Bureau of Mines paper entitled "Reservoir Characteristics of the Eunice Oil Field, Lea County, N. Mex." contains the following comments on the Eunice Field and its producing formations:

> *"In the Eunice field there are few easily recognizable geologic markers to indicate true structural conditions of the oil-productive section, due to horizontal and vertical gradation in chemical compositions and lithologic characteristics of the strata."*
>
> *"Many problems in well-completion and production practice have been met in the Eunice field because of erratic variations in porosity, permeability, in vertical distribution of "pays" and the apparent departure from ordinarily accepted relations in oil accumulation to structure."*

"In a field that produces from a uniform stratum, deposited as a parallel member of a geologic formation, the reservoir often may be defined readily from geologic information. The reservoir of the Eunice field however, cannot be interpreted so easily because it consists of a series of porous streaks or lenses that, upon casual inspection, are erratic in occurrence and have little or no relation to the attitude of the beds containing them."

"A study of these cross sections suggested the possibility of grouping the various oil and gas "pays" into three major zones, which are separated from each other by dolomitic beds through which there is little or no flow."

"The erratic character of the porosity and permeability of the major productive zones in the Eunice field has been mentioned. To illustrate some of the porosity and permeability characteristics of the reservoir, six photographs showing 12 core specimens, together with porosity and permeability data, are included in this report (figs. 11-13)."

Core 1 (porosity 19.7 percent, permeability 218 millidarcys) is a porous oolitic dolomite, at least half of the individual pore spaces of which are filled with cementing material. Although the pores are very small, this core is the most permeable of those shown.

Core 2 (porosity 23.6 percent, permeability 0.48 millidarcy) is dark-gray, flaky, sandy, and oolitic dolomite. The original pores were large and much secondary material had been deposited in them. Even though the pores appear large, the vertical permeability is low.

Core 3 (porosity 23.6 percent, permeability 35.9 millidarcys) is an example of fine-grained dolomitic sandstone. Its porosity is as high as that of any core shown.

Core 4 (porosity 10.9 percent, permeability 0.05 millidarcy) is dense white dolomite with local dark streaks, which dip at about 15° from the horizontal. Most of the original pore space is filled with secondary material.

Core 5 (porosity 8.5 percent, permeability 0.07 millidarcy) consists of gray and light buff-colored dolomitic sand with abundant inclusions of very angular dolomite fragments.

Core 6 (porosity 11.6 percent; no permeability test) contains cream-colored sandy dolomite and banded gray dolomitic sandstone. The pores in the sandstone are very small.

Core 7 (porosity 15.3 percent, permeability 5.84 millidarcys) is an example of oolites embedded in a dense flaky and sandy dolomite. The oolites are about four times as large as the grains of sandy dolomite and show hollow interiors when broken.

Core 8 (porosity 20.9 percent, permeability 18.6 millidarcys) consists of fine-grained, flaky, and partly oolitic dolomite with some very fine, irregularly spaced pores.

Core 9 (porosity 15.4 percent, permeability 0.50 millidarcy) is a uniform-gray dolomitic sandstone. Upon casual inspection, this specimen appears to have little porosity, but the test indicated more than 15 percent.

Core 10 (porosity 11.9 percent, permeability 2.97 millidarcys) is a flaky and microscopically sandy dolomite with a trace of open solution-channel porosity.

Core 11 (porosity 11.2 percent, permeability 1.95 millidarcys) is a very fine-grained, flaky, partly oolitic dolomite.

Core 12 (porosity 19.5 percent, permeability 0.95 millidarcy) is a dark-gray flaky and sandy oolitic dolomite with large pores partly filled with secondary material.

31. In Case No. 12320, a 2000 NMOCD hearing relating to the addition of five injection wells at EMSU, Chevron's petroleum engineering witness Mr. Tracy G. Love testified:

> *"This is a highly heterogeneous reservoir. Variability in porosity and permeability results in bypass reserves."*

32. Mr. Love was also one of the authors of an SPE paper entitled "Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood" SPE 49201 which identifies conformance issues at EMSU as a field wide problem.

33. Empire's witness Mr. William West testified in his corporate representative deposition:

Q. So is it not representative because the San Andres and Grayburg are heterogeneous across the unit?
A. Not heterogeneous. I mean, yes. I mean, it's not a – it is heterogenous across it that sands come and go and it is not a homogeneous environment.

34. Dr. Buchwalter's model construction does not incorporate geologic complexities or the known variations in porosity and permeability that influence production and injection at the EMSU. Therefore, conclusions or opinions based on model results or predictions are suspect.

35. Dr. Buchwalter provided no well-level pressure history matches. The field-wide pressure matches are based on very few pressure readings and, as discussed above regarding Mr. West's statement and exhibits, those pressure readings are subject to uncertainty.

30. Dr. Buchwalter testified that he did not attempt to incorporate actual well completion data in his model. From his December 13, 2024 deposition:

Q. So let me just be clear. You don't have – you weren't given completion intervals for any of the wells in your models?
A. No. Well, I did not integrate them. You have 600-something wells here. Logically, when you complete these wells historically, they would have been completed in the oil zone. And – and as needed to improve the match, we would move those completions up into the Penrose, as well, so …
Q. I'm not just talking about the Penrose here. I'm taking about any wells completed in any one of those layers, you don't have the completion intervals – the intervals that they actually were perf'd in in your model?
A. We don't have that, no. I don't have those details.

31. It was very common for wells that ultimately were included in the EMSU to be recompleted, plugged back or deepened over time. For example, after unitization approximately 270 workovers were performed including deepening and liner settings. (SPE Paper 17221) Dr. Buchwalter's model does not honor this data and therefore fluid withdrawals may occur from model depths or layers that differ from what actually occurred. This creates additional uncertainty with model results and predictions.

32. Dr. Buchwalter asserts that there is a connection between the Grayburg formation and the San Andres formation because model wells in the central portion of the field would not produce enough water to match the historical water production. Dr. Buchwalter modified the vertical permeability (KZ) in individual cells of the model to allow the San Andres formation to provide that water at specific well locations.[5] However, the lack of water production (in the model) was restricted from the Grayburg by both an usually high immovable water saturation (see Rebuttal Statement of Dr. Larry Lake) and the closing off (in the model) of the Grayburg formation on the western edge of the EMSU. In certain wells, Dr. Buchwalter's unmodified KZ history matches imply that the Grayburg would produce water free.[6] Dr. Buchwalter's truncation of the Grayburg formation[7] and the exclusion of its water source conflicts with Chevron's testimony and technical paper[8] regarding edge water encroachment, as well as Empire's own expert witness Dr. Lindsay. Dr. Buchwalter's model starves the Grayburg for mobile water through the use of a high immobile water saturation and isolation to the west, so it is not surprising that water can be made to move from the San Andres to the Grayburg via model-imposed connections by manipulating vertical permeability values in select model cells. In my opinion, Dr. Buchwalter effectively considered and modeled only one possible source of water production. As Dr. Lindsay opined in his deposition, any reservoir simulation that failed to include edge water encroachment will not accurately represent the fluid movement or production in the EMSU. **Exhibit Goodnight F-27**

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[5] Empire Base Case Model Simulation Input Grids IMPORTANT DATA.xlsx, tab KZ Layer 8.
[6] Only 6 wells in KZ modified blocks were included in Dr. Buckwalter's self-affirmed statement. Based on information provided by counsel, approximately 50 wells are in grid blocks with KZ modification.
[7] Empire Base Case Model Simulation Input Grids IMPORTANT DATA.xlsx, Layer 1-7 Net Thickness tabs, and Layer 1-7 Porosity tabs.
[8] SPE 49201 Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood, Love, McCarty, Miller and Semmelbeck.

33. Given these shortcomings, the conclusions Dr. Buchwalter draws based on his model simulations are not applicable to the actual wells and formations in the EMSU. In particular, his conclusion that San Andres water from Goodnight's disposal operations is currently communicating in large volumes through fracture pathways into the Grayburg, interfering with EMSU operations, is not substantiated by production field data. If that were the case, Empire would have had every incentive to present data from its offsetting wells showing changes in water production over time. The fact that it has not presented such data speaks volumes.

CONCLUSION

Based on my review of the available data and information as well as Empire's witnesses' opinions discussed above, I concluded that:

- Mr. West's economic calculations of assumed San Andres ROZ projects are based on unsupported and unreliable data and therefore they do not prove the economic viability of such plans.
- Mr. West's calculations and opinions regarding the connection between the Grayburg and San Andres formations are unfounded.
- Dr. Buchwalter's reservoir model does not incorporate known geologic complexities, sources of water influx or important historical well data and therefore his conclusions and opinions based on model results are unreliable.

I affirm under penalty of perjury under the laws of the State of New Mexico that the foregoing statements are true and correct. I understand that this self-affirmed statement will be used as written testimony in this case. This statement is made on the date next to my signature below.

John C. McBeath, P.E.
John C. McBeath, P.E.

Feb. 7, 2025
Date

 REBUTTAL EXHIBIT F-21

for lunch and get some -- get our blood sugar levels back up. Fair?
A. Uh-huh.
Q. Okay. The next section I want to discuss with you is more about -- is kind of more specific about how to define ROZ, because I think this is kind of the -- part of the heart of your testimony, okay, and I want to make sure -- because I want to take your definition, your understanding of what the parameters are of an ROZ, and I'm going to try to figure out how that applies to our case. All right?
A. Okay.
Q. Now, I think -- I think you've actually got a nice exhibit that kind of sets out what the parameters are, and I'm going to see if I can get to that in the testimony and share my screen. I'll just keep this up as we talk through this.
A. Okay.
Q. Now, I know earlier on you said, you know, ROZs are kind of, like, you know, you know it when you see it. But these are some -- you agree with me that these are some gui- -- at least guiding principles or guiding factors that help you evaluate or characterize whether a zone is an ROZ or not?
A. Yeah.

Q. Okay.
A. This is what an ROZ would -- we're making a comparison to a -- you know, an efficient mature waterflood versus what an ROZ looks like, because they do have similarities but they also have some differences.
Q. And I'm going to try to put this in the context now of a Brownfield ROZ, because as I understand now your testimony that needs to be corrected here is that San Andres -- or clarified -- is that the San Andres within the EMSU is a Brownfield ROZ?
A. Right. Because it exists below a main pay. Uh-huh.
Q. Okay. And that's helpful, I think, here because -- especially where we're looking at the parameters, because you have a main pay and you can evaluate the San Andres relative -- or, rather, the San Andres ROZ relative to the main pay; right?
A. Yeah.
Q. And the main pay in this case has been -- has undergone a man-made waterflood. So that -- so as I understand as I read your papers, the -- one characteristic of an ROZ is that you can look at a mature waterflood, and that's one way, and evaluate it based on the comparison to a mature waterflood; right?
A. Correct. Uh-huh.

Q. Okay. So -- so the first bullet here is you got a -- SO, as I understand it, is the oil saturation?
A. Yes. Uh-huh.
Q. So the residual oil saturation in an ROZ you expect to be 20 to 40 percent; right?
A. Right. And it's very often referred to the S- -- as SORW, saturation of water residual to waterflood.
Q. Okay. And that -- and that SORW is applied whether it's a Mother Nature Waterflood or a man-made waterflood?
A. Yeah, they're similar saturations. Except in the Mother Nature's, we say it's equivalent to what we see in the -- in the waterflood. So we wouldn't -- in a residual oil zone, we wouldn't call it SORW. So we just call it SO.
Q. But on -- in this parameter, though, I mean, you use 20 percent. And I've read through a lot of your papers, and it seems to me that 20 percent is sort of -- is your cutoff for what is deemed to be commercial ROZ?
A. It's going to go case to case, but that's a starting point, yeah.
Q. Are you aware -- have you identified any ROZ project where they're targeting an interval that's less than 20 percent oil saturation?
A. Not in areas where they don't have at least a good section of higher than 20 percent as well.

Q. Okay. I'm going to explore this a little bit with you. So you're aware of at least some ROZ projects where they have included some intervals that are maybe below 20 percent, but only where there is a -- intervals with higher than 20 percent?
A. Yeah, that -- specifically, that may be a question for Steve Melzer, because he talked about those lower oil saturations. So he's familiar -- he may be a little bit more familiar with the lower cutoff than I would be.
Q. Well, I've got some -- I have some papers that I'm going to walk through you, okay. But I just want to understand, I mean, so you're -- right now, as we sit here, you're saying that the 20 percent is a good guide. It's not necessarily -- you have to look at it case by case, okay?
A. Yeah. Uh-huh.
Q. Is that fair?
A. Yes.
Q. And then another parameter that you're looking at is that you expect it to be more homogenous?
A. Potentially, yes. Because in most -- in many of the San Andres reservoirs where we have a main pay and an ROZ, and it's going to be true here as well for another reason, as you're coming up through the San Andres section, overall the sea level is falling; therefore, the near shore or shore facies are moving out across the reservoir. So in

of a standard to demonstrate that point; that when you look at the core saturations of oil in the ROZ and you compare them to the main pay of a mature waterflood, that the oil saturations are comparable, they look very similar; is that right?
A. Yes.
Q. And that's -- that's the main takeaway from this graph, is that comparison of oil saturations between the two zones?
A. Yeah.
Q. And here, going back to that same point where you identified the range of the ROZ between 20 percent and 40 percent oil saturations, here the cutoff appears to be at approximately, you know, 20 percent. Agree?
A. Yes, about 20 percent. Uh-huh.
Q. And I -- and I, you know, was curious about this so I went back and looked at some other papers, and I know that you guys published some final reports about this field where you've identified on a ten-foot incremental basis the oil saturations for each of these zones, including down to these zones where you've identified these as being noncommercial. Do you recall doing that work?
A. Yes. Uh-huh.
Q. Okay. And here you've identified this as the commercial flood interval, at least for this field. In

other words, as I understand it, from the main pay or even the oil gas cap, down to approximately this blue line on the far line of this plot is identified as the commercial CO2 flood interval. Agree?
A. Yes.
Q. Okay. And as I understand now -- now, it's not in this -- this is -- this paper here, but one of the other papers, and I can -- I'll pull it up -- you discussed this same plot. And the feature here is that, I think, as I understand it, is partly one of the tools you used to identify the base of the ROZ, is where this dropoff occurs; is that right?
A. That's one of the tools, yeah.
Q. When I say "dropoff," I mean the transition of the shift from a higher oil saturation from 20 percent above, down to a lower oil saturation below approximately 20 percent. Agree?
A. In this field, that goes along with a change in lithology that the ROZ and the main pay are dolomite reservoirs, and the interval below the base of the ROZ is a limestone. So there's a change in facies as well, and it's -- it occurs over about a foot. So...
Q. So it's a sharp change between approximately where this 20 percent oil saturation occurs?
A. Yeah. And that goes along with the change in

lithology because there is very little porosity in the interval below the base of the main pay -- below the base of the ROZ, because you've got a change in lithology as well. So there's two things going on there.
Q. Now, so below this 20 percent interval, as I understand it in the Goldsmith, you agree that this interval below 20 percent oil saturation is not commercial. Agree?
A. Yes.
Q. And it's not commercial because of the oil saturations?
A. And the fact there's no porosity and you've a change in lithology from dolomite above to limestone below.
Q. Okay. Those two -- those two factors evaluated -- now, did you discuss the lithology change in your determination, in your papers, in your reports as being a characteristic of that zone not being commercial or not being a target? Do you recall?
A. We didn't talk specifically about a change in lithology indicating a change from commercial to noncommercial. We did mention -- we did talk about the fact that there was limestone below, but this is -- this is one case, and in this one case, if there's a transition from dolomite to limestone, we didn't see that in any of the other ROZ fields where we see the transition from ROZ to the interval below the original oil/water content.

Q. In any of the other ones that you're familiar with, you didn't see a corresponding change in the lithology from, like, dolomite to limestone?
A. Not that I -- not that I can recall. I don't think there was any one.
Q. Okay. So let me kind of drill down a little bit on the oil saturation question. Of the 19 or so projects in the 12 or so ROZ fields -- I'm sorry, Let me restate that. Of the 19 or so ROZ projects in the 12 dozen or so ROZ fields, are you aware of any pilot or commercial project that is targeting an ROZ interval with oil saturations below 20 percent?
A. They will include that interval in their ROZ, but not specifically targeting it.
Q. In other words, are you aware of any ROZ projects or zones that are targeting intervals that are below 20 percent oil saturation?
A. Not by themselves, no.
Q. Okay. So if there's a -- if there's a depth interval that -- where the oil saturation goes from 20 percent on average, okay -- say there's a ten-foot interval with an average oil saturation of 20 percent. And then every ten-foot increment below that is below 20 percent. Okay. Are you aware of any ROZ projects that are targeting those intervals below the lower most interval

main pay, or --
Q. Well, let me ask you this: If we have production data from production tests in what's proposed as an ROZ, and we have water supply wells producing from what is proposed as the ROZ, so we've got effectively production data, is that not an op- -- give us an opportunity to history match to the log analyses?
A. I don't see how that would be, because we know that the ROZs aren't productive in a main pay primary production example. So just the fact that if you're producing water from an interval and not producing oil, doesn't tell you that you have an ROZ. So I have a problem with that statement.
Q. Okay. Let me ask you this, then: If that's the case, okay, so you're saying it wouldn't work because you aren't producing the interval as an ROZ. You're not flooding it with CO2, so it's not going to be -- it's not going to be a history match -- a true history match; right?
A. That would be correct, yeah.
Q. Okay. So let's -- let's take it to ano- -- and apply it another way. So say we had a log and a petrophysical model, okay, that we applied to a series of logs. And we then took that model and we applied it to an analogue that is an ROZ in the same -- in the same formation. Okay. So, for example, if I took -- you know,

let me ask you this: The Seminole San Andres unit, the Hess Unit, that was a -- that's a -- that's a Brownfield ROZ; correct?
A. Right.
Q. So we have a main pay overlying an ROZ?
A. Uh-huh.
Q. Agree? Now that -- that ROZ was identified as an ROZ and was produced as an ROZ, right, with a CO2 flood?
A. Right.
Q. And if I were to take logs from a different zone in a different area and I were to come up with a petrophysical model that was able to history match the San Andres ROZ with its logs, would that be a fair -- would that give me some comfort that my logs are not lying if I'm able to history match against a Seminole San Andres log with the ROZ production?
A. Are you talking about another area where you have an ROZ production or where you are trying to establish ROZ production?
Q. We're trying to establish ROZ production. So you have logs --
A. Yeah, history match, to me, is, you know, you take the history of all the production up to today, and then you -- going forward you do a simulation. So a history match, yes, you've got a history -- you can do a history

match for Seminole San Andres, but that doesn't mean that same history match at Seminole would be -- if you don't have production somewhere else, you can't have a history match, is I guess what I'm saying.
Q. Okay. Well, let me -- let me -- I'm going to put that conversation aside for now, because -- I may come back to it at the end. I don't want to get bogged down on it because I have other things I want to touch on. But I think I may -- I may come back to it. So let's put a pin on it, so to speak, and I may come back and see if I can get my terminology more aligned with how I think you're thinking about it in the interim.
Let's see. Now, and I don't want to, like, get stuck on this 20 percent, but it is a point I want to just make sure I understand. In your testimony that's marked as Exhibit D-2 that you filed in the case here, the parameters that you give throughout is that the ROZ is -- is identified as having an oil saturation be 20 percent and 40 percent.
And based on our discussion, I'm not aware of, and I personally haven't identified any other ROZ projects or developments, pilot or commercial, that -- where the -- and I think you told me, yes, that there's no -- none that you're aware of where the averaged ROZ interval of the entire ROZ interval is below 20 percent; right?
A. That's correct.

Q. Okay. All right. That's where I got off on my tangent, so I'll try to pick back up there.
A. There's one qualifier I will add. Also in my testimony, I talked about what Hess did in Seminole was they -- they ran pressure cores, sponge core and conventional core, and the difference is, besides pricing and the engineering, they noticed the difference in the oil saturation from the conventional to the sponge to the pressure core. But in the conventional core, you're just -- had the core bit and the care barrel and you're just going ahead and you're making no special rationale for changing anything other than the flui- -- the fluids you've got, you've got, and so you're not going to do anything different.
The sponge core, there's a lining in the core barrel of literally a sponge separated from the core by a -- kind of a steel cage. And because when you're coring and when you're bringing the core to the surface, you're likely to lose some of the oil saturation in the core.
You're going to kind of flush it a little bit when you're -- with the fluids that you're coring with. And as you're bringing it to the surface, you're dropping pressure so you're going to expel a little bit of the oil.
So conventional core loses some of the oil saturation that you have by the time -- by the time you've done the

Q. Do you have an understanding whether that's -- Empire's going to do that?
A. Well, that's up to them. 11:57
Q. You have no indication from them that they're going to do that?
A. They say they will, but that's all I've heard.
Q. Who said that they will? Do you remember who said that?
A. Pardon?
Q. Do you remember who it was that said they will?
A. Will what?
Q. They will take a core of the Lower San Andres.
A. Oh, you'd have to talk to Darrell Davis about that. 11:58
Q. Was that Darrell Davis who told you that they plan to or they will?
A. Uh, yes.
Q. We've talked about this term residual oil zone, the ROZ, but we really haven't talked about how you define it. What is your definition of a residual oil zone? 11:58
A. Anything that has an oil saturation greater than 20 percent, up to at least maybe 40 percent, 50 percent, until you get to the point where you finally have mobile oil in a core. 11:58
Q. Just to confirm that, my understanding is that

aligns with the definition in the literature adopted by Mr. Melzer -- or Dr. -- Mr. Melzer and Dr. Trentham. Agree?

A. Yes, that's correct.

Q. And are you aware of any ROZ Co2 projects that 11:59 have pursued ROZ zones with oil saturations below 20 percent?

A. No.

Q. In addition to those oil saturations is it your understanding that oil within an ROZ would be immobile, correct?

A. You know, people -- excuse me. People talk about residual oil zones being just nothing but residual, 12:00 but in reality when you look at residual oil zones, from top to bottom you go from higher oil saturation to lower. And in the upper part some of that what is called residual is actually mobile or you could never produce it to begin with if you do a residual oil zone now when you drill a 12:00 well for a residual oil zone.

Q. I'm not sure I quite -- I may have been distracted. I wasn't quite following that last bit.

MR. PADILLA: Your calendar's up again.

A. When you look at a residual oil zone from top to bottom, the oil saturations go from higher to lower. In 12:00 the top of the residual oil zone some of that oil is

 REBUTTAL EXHIBIT F-22

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Estimates of Potential CO_2 Demand for CO_2 EOR in Wyoming Basins

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Abstract

A database of Wyoming oil reservoirs is developed to identify candidate reservoirs suitable for miscible or immiscible CO_2 flooding, a method that has already proven to be a viable enhanced oil recovery process at Lost Soldier, Wertz, and Salt Creek fields in Wyoming. Based on the CO_2 usage of existing CO_2-EOR projects in Wyoming and other regions, the initial and total CO_2 demands are estimated for the identified reservoirs and grouped by basins. The simple formulas presented in this paper provide a quick estimation of the required initial and total CO_2 volumes with specified reservoir parameters. Wyoming has produced about seven billion barrels of oil from more than 1200 oil producing fields. 98% of the oil was produced from the top 400 fields, evaluated in this study, each with a cumulative production exceeding one million barrels of oil. More than 500 oil reservoirs, by passing either miscible or immiscible screening criteria, are identified as potential CO_2-EOR candidates. Large fields often have multiple oil producing reservoirs suitable for CO_2 flooding. It is estimated that 1.2 to 1.8 billion barrels of additional oil might be recovered by CO_2 flooding and up to 20 trillion cubic feet of CO_2 could be sequestrated after CO_2 EOR in Wyoming's oil basins.

Introduction

CO_2 flooding has already proven to be a viable enhanced oil recovery process in many geographic locations. Wyoming has significant natural sources of CO_2 in several of its existing gas reservoirs that have relatively high CO_2 concentration in their natural gases (De Bruin, 2001; Nummdeal et al., 2003). ExxonMobil operates one of the world's largest CO_2-producing fields at the La Barge anticline in southwestern Wyoming. Five Wyoming fields are currently under CO_2 flooding using the CO_2 supplied by a CO_2 pipeline network that originates at ExxonMobile's gas plant at Shute Creek (Figure 1). Amoco initiated Lost Soldier and Wertz CO_2 miscible floods in late 1980s. The two fields were purchased by Merit Energy Company in 1999 and are still under CO_2 Injection. In 2003, Anadarko constructed a 125-mile pipeline to transport La Barge CO_2 for its EOR project at the Salt Creek field in the Powder River basin and, in the same year, completed another 33-mile pipeline spur to supply CO_2 to flood the Monell Unit at the Patrick Draw field in the Greater Green River basin. The Beaver Creek CO_2 flood, operated by DevonEnergy Corp, is the newest addition to Wyoming's CO_2-EOR portfolio. The field is located on the west flank of the Wind River basin and has been under CO_2 injection since July 2008. A newly constructed 45-mile pipeline brings the CO_2 from the Bairoil station near Jeffrey City to the Beaver Creek field. The increment oil produced from those CO_2 floods has been substantial. The cumulative oil by CO_2 EOR from the Tensleep reservoir at Lost Soldier alone is more than 22 million barrels of oil (MMBO), or 11% of the estimated original oil-in-place (OOIP). By May 2008, CO_2 flooding has already produced 5.5 MMBO at Salt Creek and 3 MMBO at Monell Unit (Gaines, 2008).

The success of the CO_2 floods has drawn a special interest in Wyoming. Many CO_2-EOR projects are currently under evaluation or in planning. However, the biggest challenge for many small producers is access to CO_2 at an affordable price. With Wyoming's vast coal reserves and an increasing concern over climate change, new coal-fired power plants and coal-to-liquids plants are being designed to have CO_2 capture capability. The captured CO_2 will provide Wyoming oil producers additional CO_2 sources for their CO_2-EOR projects. The purpose of this study is two-fold: first, to screen for Wyoming oil reservoirs that are technically suitable for CO_2 flooding and second, to provide a method that quickly estimates the potential CO_2 demand for CO_2-EOR candidate reservoirs. The resulting database and CO_2 demand estimation should be useful for CO_2 suppliers to foresee the market volume for CO_2 EOR in Wyoming basins.

CO_2 EOR has been tested and developed for more than four decades. It becomes a mature technology as demonstrated by more than 80 projects worldwide. Sequestration of CO_2 in partially depleted oil reservoirs is an attractive option, not only because of the economic benefit from EOR, but also because of the availability of reservoir data and infrastructure that can be utilized to facilitate CO_2 storage projects.

Screening of CO_2-EOR Candidate Reservoirs

The primary objective of CO_2 EOR is to remobilize and dramatically reduce the post waterflooding residual oil saturation in reservoir pore space. Miscibility between reservoir oils and injected CO_2 usually develops through a dynamic process of mixing, with component exchange controlled by phase equilibria and local compositional variation along the path of displacement. CO_2 is not miscible on the first contact with reservoir oils. However, with a sufficient high pressure, CO_2 could achieve dynamic miscibility with reservoir oils in a multiple contact process. During this multiple contact process, CO_2 will vaporize the lighter oil fractions into the injected CO_2 phase and CO_2 will condense into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, a mobile fluid and low interfacial tension (Stalk, 1984). As long as a minimum miscibility pressure (MMP) can be achieved in a reservoir, CO_2 flooding should result in an oil recovery greater than 90% OOIP in the swept region (Taber et al., 1997). The slim tube test has been used for decades as a common method for determining MMP. Where no measured MMP is available, MMP is often estimated from empirical correlations, such as the Cronquist correlation, based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil.

When reservoir pressure is insufficient or reservoir oil composition is less favorable (heavier), the injected CO_2 is immiscible with reservoir oil. However, the interactions between injected CO_2 and reservoir oil can still remobilize some of the residual oil from waterflooding. The main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and, (4) fluid drive plus pressure (Mungan, 1981; Jarrel, 2002). This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced. In general, immiscible CO_2 EOR is less efficient than miscible CO_2 EOR in recovering the remaining oil after waterflooding.

By the end of 2008, Wyoming had produced more than 7.1 billion barrels of oil from 1,237 oil producing fields. However, production from many of the fields is small with a few oil producing wells. About 98% of the total oil was produced from the top 400 fields that have a cumulative production exceeding one million barrels of oil (MMBO). For identifying candidate reservoirs suitable for miscible or immiscible CO_2 flooding, a database of Wyoming oil reservoirs was developed, which includes the production data from Wyoming Oil and Gas Conservation Commission (WOGCC), measurements of 901 Wyoming oil samples from the DOE_coa database and other reservoir parameters digitized from the Wyoming Geological Association (WGA) publications.

A number of screening criteria to identify candidate reservoirs for CO_2 EOR can be found in publications such as Stalkup (1984), Diaz et al. (1996) and Taber et al. (1997). Oil viscosity and API gravity as well as reservoir depth and temperature are commonly used as the key screening parameters. In addition, a good waterflood response, and sufficient porosity (> 7%) and permeability (> 10 md) are also required for a successful CO_2 flood. Because the purpose of this study is to assess the potential CO_2 demand for reservoirs that are technically suitable for CO_2 flooding, economic factors such as oil price and distance to CO_2 source are not included in the screening. Only the top 400 fields were evaluated in this study to exclude fields with a cumulative oil production less than one MMBO. There are 1,368 reservoirs from the top 400 fields generated as the initial pool for screening. 528 reservoirs pass the minimum depth cut off (>1,800 ft), oil gravity cut off (>13 ^oAPI), and cumulative production cut off (> 1 MMBO) as CO_2-EOR candidate reservoirs. Figure 2 shows the number of candidate reservoirs, in the inserted table, and their cumulative oil productions grouped by basins. Lost Soldier and Wertz fields are already in their final phase of CO_2 flooding operation and, therefore, are not included in the screening. The candidate reservoirs are further screened into two groups: miscible and immiscible, based on the following screening criteria.

Screening criteria for miscible CO_2 flooding

- Sandstone or carbonate reservoir only
- Porosity porosity > 7% and permeability > 10 md
- Oil gravity > 22 ^oAPI
- Reservoir depth > 2,500 ft
- Oil viscosity < 10 cp, at reservoir condition
- Cumulative oil production > 1 MMBO

Screening criteria for immiscible CO_2 flooding

- Sandstone or carbonate reservoir only
- Porosity porosity > 7% and permeability > 10 md
- 13 $^oAPI \leq$ oil gravity $\leq$ 22 ^oAPI
- 1,800 ft $\leq$ reservoir depth $\leq$ 2,500 ft
- 10 cp $\leq$ oil viscosity < 600 cp, at reservoir condition
- Cumulative oil production > 1 MMBO

The miscibility between reservoir oil and injected CO_2 is a complex process as discussed above. Because of higher reservoir temperature or unfavorable oil composition, a miscible flooding may not be achieved in a reservoir even thought it passes the miscible flooding criteria. Thus, the proposed criteria for miscible CO_2 flooding should be regarded as potentially miscible criteria. As shown in Figures 2 and 3, most of the candidate reservoirs are located within Wyoming's four large oil producing basins: Power River, Bighorn, Wind River and Greater Green River basins. More than half of the total candidate reservoirs are in the Power River basin, which consists of 124 relatively small Minnelusa reservoirs. Large candidate reservoirs are more concentrated in the Bighorn basin, mostly Tensleep, Phosphoria and Madison reservoirs. Tables 1 and 2 list the major reservoirs identified from screening as potentially miscible and immiscible CO_2-EOR candidates, respectively.

Estimation of Total and Initial CO_2 Demand

In many CO_2 flooding projects, CO_2 is injected alternately with water, such as the Lost Soldier and Wertz CO_2 miscible floods in Wyoming. The concept of using CO_2-WAG (water alternating gas) injection technique is to improve injection profile and reduce gas channeling. The performance of CO_2-WAG floods from a similar formation may likely be scaled into one dimensionless curve of incremental oil, as a percentage of hydrocarbon pore volume (HCPV), versus injected WAG volume in HCPV. The dimensionless curve obtained from the CO_2-WAG flood in the Tensleep reservoir of Lost Soldier is shown in Figure 4 and is compared with the typical dimensionless curve from the CO_2-WAG floods in the San Andres reservoirs of west Texas. For similar type of reservoirs using a same CO_2 flood scheme, the dimensionless curve method could provide a quick assessment of potential oil recovery as well as required CO_2 injection volume. In this study, estimation of CO_2 demand is based on the performance of existing CO_2-WAG floods. For reservoirs with large dip angles or high concentration of vertical fractures, gravity stable CO_2 injection could be a more effective flood scheme, which is discussed in the next section.

Estimation of total CO_2 demand for a CO_2-WAG flood

The duration of a CO_2 flood project usually lasts for a few decades and the majority of the injected CO_2 is produced and re-injected. As given in Eq. 1, the estimated total CO_2 demand only takes account of the net CO_2 volume that needs to be purchased.

$$T_{CO2} = \frac{(1-\omega_{CO2}) \times C_{WAG} \times H_{WAG} \times B_o \times OOIP}{B_{CO2}} \qquad (1)$$

where B_o and B_{CO2} are the oil and CO_2 formation factors, respectively. ω_{CO2} represents the average fraction of the injected CO_2 that is produced and re-injected. The CO_2 volume fraction in WAG, C_{WAG}, is calculated at reservoir condition. H_{WAG} is the injected total WAG volume in HCPV and T_{CO2} is the estimated total CO_2 volume in MCF. For the CO_2-EOR candidate reservoirs in Wyoming basins, a 70% CO_2 re-injection rate, 1:1 WAG ratio and a total WAG injection of 2.5 HCPV are assumed in this evaluation. Consequently, Eq. 1 is further simplified as

$$T_{CO2} = \frac{0.3 \times 0.5 \times 2.5 \times B_o \times OOIP}{B_{CO2}} \qquad (2)$$

Trustworthy OOIP data of Wyoming oil reservoirs are rarely available. Traditionally, volumetric calculation or decline curve analysis is used in the estimation of OOIP but it is difficult to verify the consistency of the methods used in previous estimations, especially if a large number of reservoirs are concerned. In this evaluation, OOIP is estimated from reservoir cumulative production and recovery factor. Most of Wyoming oil reservoirs have been under water-drive production for decades. Many of the reservoirs are naturally fractured and their recovery efficiency can vary substantially depending on reservoir properties and engineering practice. Therefore, instead of assuming one average recovery factor, a low recovery factor of 30% and a high recovery factor of 45% are both used to provide a range of estimated OOIP.

CO_2 formation factor, B_{CO2}, is determined by reservoir pressure and temperature according to the data table provided by Jarrell et al. (2002). For reservoir pressure or temperature that is not included in the table, B_{CO2} is estimated by linear interpolation from the four nearest formation factors that are available in the table. The estimated CO_2 demands for miscible and immiscible CO_2 EOR in Wyoming basins are summarized in Figures 5 and 6, respectively. In combination, the estimated total CO_2 demand ranges from 6.1 to 9.2 TCF in Power River, 4.8 to 7.2 TCF in Bighorn, 1.2 to 1.8 TCF in Wind River, 1 to 1.4 TCF in Greater Green River, 0.68 to 1.02 TCF in Overthrust Belt, 0.09 to 0.13 TCF in Laramie, and 0.08 to 0.12 TCF in Denver-Cheyenne basins.

Estimation of initial CO_2 demand for a CO_2-WAG flood

Reservoir injectivity is another key factor for a successful CO_2 flood. An annual WAG injection between 5% and 10% HCPV is typically required in the design of a field flood project. Higher volume injections, 10-15% HCPV per year, have been observed in projects with good flooding performance. A CO_2 flood project may be economically unviable under very low annual injection volume, i.e. less than 4% HCPV per year. In the initial phase of a WAG flood, no CO_2 will be produced until the breakthrough of CO_2 at the production wells and the injected CO_2 needs to be fully supplied from external sources. The initial CO_2 demand can be estimated from Eq. 3.

$$I_{CO2} = \frac{C_{WAG} \times I_{WAG} \times B_o \times OOIP}{365 \times B_{CO2}} \tag{3}$$

where I_{WAG} is the annual WAG injection volume in HCPV and I_{CO2} is the estimated daily CO_2 injection rate in MCF/day. In this evaluation, a 1:1 WAG ratio and an annual WAG injection of 10% HCPV are used in the estimation of initial CO_2 demand (Eq. 4).

$$I_{CO2} = \frac{0.5 \times 0.1 \times B_o \times OOIP}{365 \times B_{CO2}} \tag{4}$$

The estimated CO_2 demand for the top 100 reservoirs identified as miscible CO_2-EOR candidates is given in Table 1, along with reservoir depth and oil API gravity. A similar table of the top 20 reservoirs of immiscible CO_2-EOR candidates is given in Table 2.

Results and Discussion

Large fields usually have multiple oil producing reservoirs that are suitable for CO_2 flooding. Because the CO_2 demand is ranked by reservoir, not by field, the estimated volumes in Tables 1 and 2 may not reflect the total CO_2 demand of a field if some of its small reservoirs are not included in the tables. Many existing CO_2-EOR projects have been developed by phases, often starting with small scale patterns of pilot flooding. Notice that the estimation of initial CO_2 demand in this study is calculated under the assumption of a full reservoir flooding.

As indicated from the dimensionless curves (Figure 4), the miscible CO_2 flooding has recovered about 11% of OOIP from the Tensleep reservoir at the Lost Soldier field and much higher recoverys have been observed from the CO_2 floods in the San Andres reservoirs of west Texas. The recovery factor from immiscible CO_2 floods is generally lower than miscible floods depending on actual oil and reservoir conditions. By assuming an average recovery factor of 10% OOIP for miscible CO_2 floods and 6.5% for immiscible CO_2 floods, it is estimated that 1.21 to 1.81 billion barrels of additional oil might be recovered from CO_2 EOR in Wyoming, in which the recovery from miscible floods accounts for 79% of the total incremental oil.

The estimation of total and initial CO_2 demand, i.e. Eq. 1 and Eq. 3, is essentially based on the CO_2 usage of existing CO_2-WAG floods. However, for reservoirs with large dip angles or high concentration of vertical fractures, gravity segregation of injected CO_2 and water might leave a large volume of remaining oil uncontacted with injected CO_2 and, consequently, reduce the overall WAG flooding efficiency. For such reservoirs, continuous CO_2 injection at the top of reservoir structure, i.e. gravity stable CO_2 injection, could be more effective than WAG flooding, especially for projects designed for the dual-purpose of CO_2 EOR and CO_2 storage (Wood et al., 2006). Gravity stable CO_2 injection usually requires considerably more CO_2 than WAG injection. For example, the estimated total CO_2 demand for a WAG flood in the Muddy reservoir of Grieve field is between 77 and 116 BCF of CO_2. By comparison, the CO_2 required for gravity stable CO_2 flooding in the same reservoir is estimated to be in the 119 to 188 BCF range depending on the operation duration and CO_2 injection rate (Wo et al., 2008).

Conclusions

Wyoming has a large number of oil reservoirs in the Powder River, Bighorn, Wind River, and Greater Green River basins where CO_2-based EOR is technically feasible. The state is in a unique position to couple the environmental benefits of CO_2 sequestration in mature oil reservoirs with the economic offset through enhanced oil recovery. The main outcomes from this study are listed below:

1. A database of Wyoming oil reservoirs is developed to screen candidate reservoirs suitable for miscible or immiscible CO_2 flooding. 379 reservoirs pass the screening criteria for miscible CO2 flooding, while 138 reservoirs are identified as potential candidates for immiscible CO2 flooding.
2. Based on the CO_2 usage of existing CO_2-EOR projects in Wyoming and other regions, simple formulas are provided for allowing a quick estimation of the required initial and total CO_2 volumes for a candidate reservoir.
3. The estimated total CO_2 demand for CO_2 EOR ranges from 6.1 to 9.2 TCF in Power River, 4.8 to 7.2 TCF in Bighorn, 1.2 to 1.8 TCF in Wind River, 1 to 1.4 TCF in Greater Green River, 0.68 to 1.02 TCF in Overthrust Belt, 0.09 to 0.13 TCF in Laramie, and 0.08 to 0.12 TCF in Denver-Cheyenne basins.
4. It is estimated that 1.2 to1.8 billion barrels of additional oil could be recovered by CO_2 flooding and up to 20 trillion

cubic feet of CO_2 could be sequestrated after CO_2 EOR in Wyoming's oil basins.

Acknowledgements
We thank Wyoming Oil and Gas Conservation Commission for providing field and reservoir production data, Kera Presenkowski and Matthew Johnson for help on data editing. This work was supported by the Enhanced Oil Recovery Institute of the University of Wyoming.

Nomenclature
B_{CO2} = CO_2 formation factor
BO = barrel of oil
B_o = oil formation factor
C_{WAG} = fraction of CO_2 volume in total WAG volume
BCF = billion standard cubic feet
EOR = enhance oil recovery
HCPV = hydrocarbon pore volume
H_{WAG} = total WAG injection volume, HCPV
I_{CO2} = initial daily CO_2 demand, MCF/day
I_{WAG} = annual WAG injection volume, HCPV/year
MMP = minimum miscibility pressure
MMBO = million barrels of oil
MCF = thousand standard cubic feet
OOIP = original oil in place
TCF = trillion standard cubic feet
T_{CO2} = total CO_2 demand, MCF
WAG = water alternating gas
WGA = Wyoming Geological Association
WOGCC = Wyoming Oil and Gas Conservation Commission
ω_{CO2} = fraction of recycled CO_2 in total injected CO_2

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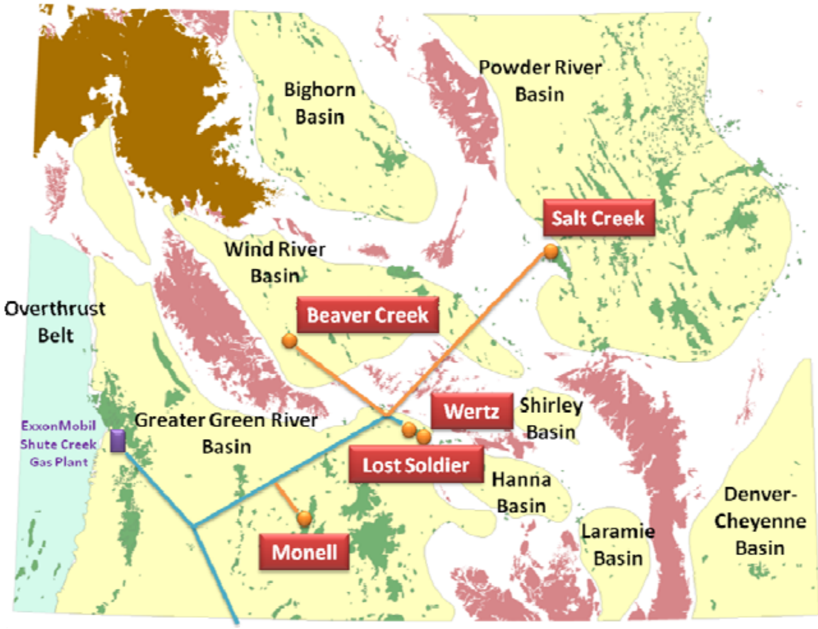


Figure 1. Wyoming basin map with existing CO_2 pipelines and CO_2 flooding fields

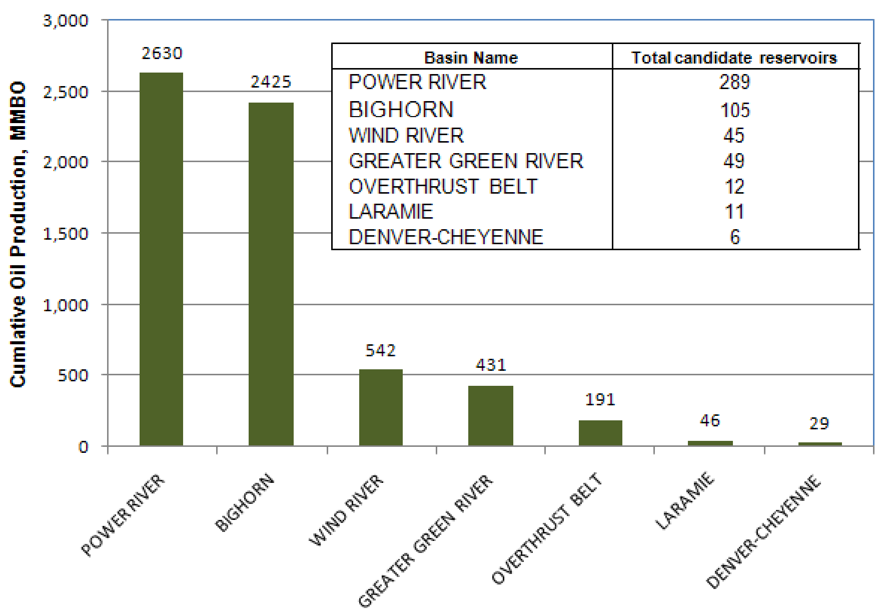


Figure 2. Number of CO_2-EOR candidate reservoirs and their cumulative oil productions by Wyoming basins

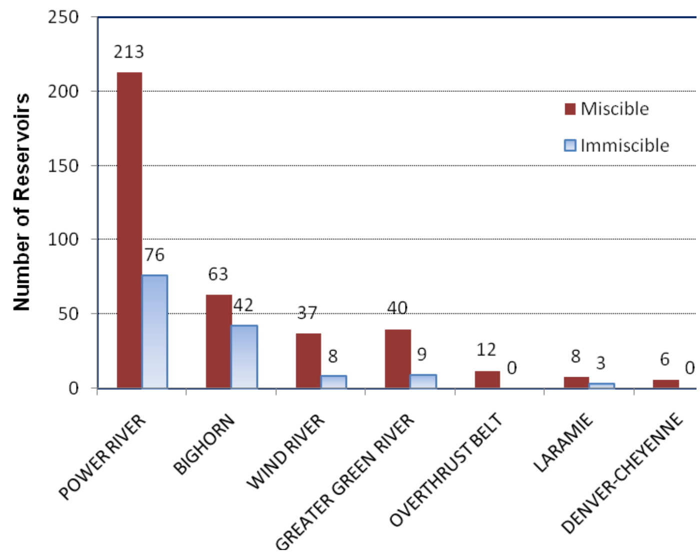


Figure 3. Number of miscible and immiscible CO_2-EOR candidate reservoirs by Wyoming basins

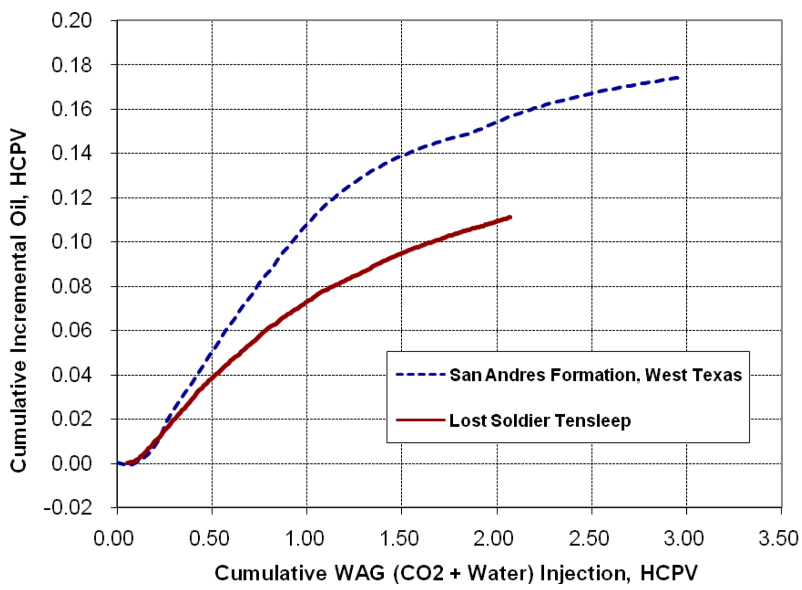


Figure 4. Dimensionless curves of incremental oil versus total WAG injection

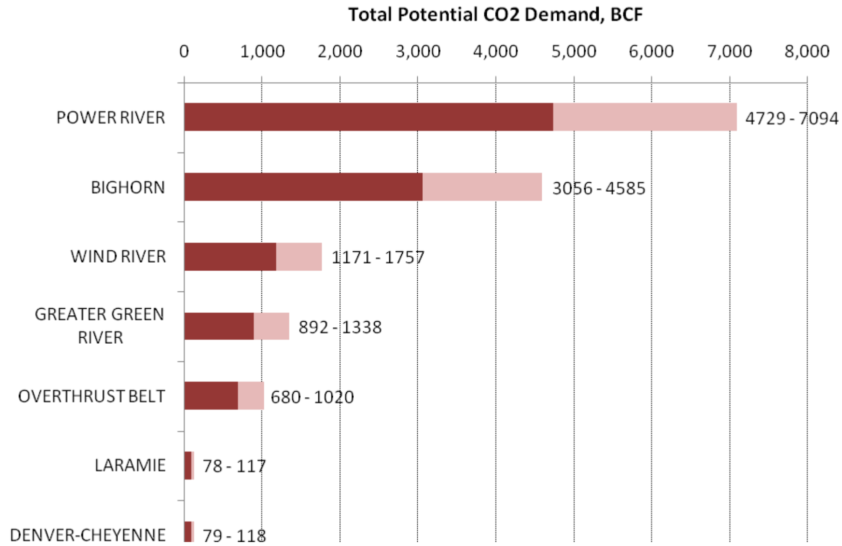


Figure 5. Estimated potential CO_2 demand for miscible CO_2 floods in Wyoming basins

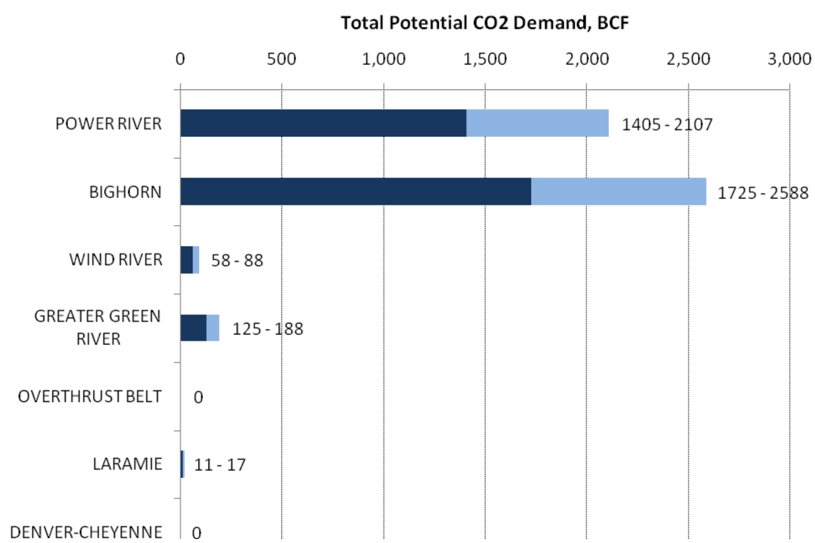


Figure 6. Estimated potential CO_2 demand for immiscible CO_2 floods in Wyoming basins

Table 1. Top 100 ranked reservoires for potentially miscible CO_2 flooding in Wyoming

Rank	Field name	Reservoir Name	Reservoir Depth ft	Oil Gravity API	Est. Total CO2 BCF	Est. Initial CO2 MMCF/D	Basin Name
1	HARTZOG DRAW	SHANNON	9485	36	564 - 846	206 - 309	POWDER RIVER
2	ELK BASIN	MADISON	5156	27.3	520 - 780	190 - 285	BIGHORN
3	ELK BASIN	EMBAR-TENSLEEP	4490	30	403 - 605	147 - 221	BIGHORN
4	PAINTER RESERVOIR EAST	NUGGET	10774	55	269 - 404	98 - 147	OVERTHRUST BELT
5	HILIGHT	MUDDY	9680	41.3	248 - 373	90 - 136	POWDER RIVER
6	BYRON	TENSLEEP	5425	25.2	244 - 366	89 - 133	BIGHORN
7	HAMILTON DOME	TENSLEEP	2863	23.8	233 - 350	85 - 128	BIGHORN
8	LANCE CREEK	LEO	5557	44.1	226 - 339	82 - 124	POWDER RIVER
9	STEAMBOAT BUTTE	TENSLEEP	6830	28.7	219 - 329	80 - 120	WIND RIVER
10	FRANNIE	PHOSPHORIA-TENSLEEP	2574	28.3	209 - 314	76 - 115	BIGHORN
11	GRASS CREEK	PHOSPHORIA-TENSLEEP	3632	24.5	192 - 288	70 - 105	BIGHORN
12	ARCH	ALMOND	5067	43.4	168 - 252	61 - 92	GREATER GREEN RIVER
13	OREGON BASIN	TENSLEEP	3850	23	159 - 238	58 - 87	BIGHORN
14	BRADY	WEBER	12082	54.7	155 - 232	56 - 85	GREATER GREEN RIVER
15	COTTONWOOD CREEK	PHOSPHORIA	7270	28.6	152 - 228	55 - 83	BIGHORN
16	PAINTER RESERVOIR	NUGGET	9958	46	147 - 221	53 - 80	OVERTHRUST BELT
17	GLENROCK SOUTH	DAKOTA	6090	34.4	136 - 204	49 - 74	POWDER RIVER
18	HOUSE CREEK	SUSSEX	8238	48.8	123 - 185	45 - 67	POWDER RIVER
19	BRADY	NUGGET	9876	50.5	122 - 183	44 - 67	GREATER GREEN RIVER
20	SUSSEX	TENSLEEP-AMSDEN	5894	33	120 - 181	44 - 66	POWDER RIVER
21	BEAVER CREEK	MADISON	10666	40.5	117 - 176	42 - 64	WIND RIVER
22	BIG SAND DRAW	TENSLEEP	6606	33.6	116 - 174	42 - 63	WIND RIVER
23	SALT CREEK	TENSLEEP	3908	28.2	100 - 150	36 - 54	POWDER RIVER
24	WELL DRAW	TEAPOT	7048	42.5	91 - 137	33 - 50	POWDER RIVER
25	STEAMBOAT BUTTE	PHOSPHORIA-TENSLEEP	6000	28.2	91 - 136	33 - 49	WIND RIVER
26	WINKLEMAN	TENSLEEP	2915	25	83 - 124	30 - 45	WIND RIVER
27	POWELL	FRONTIER	11943	48.2	79 - 119	29 - 43	POWDER RIVER
28	BYRON	EMBAR-TENSLEEP	5238	24.5	79 - 119	29 - 43	BIGHORN
29	GRIEVE	MUDDY	6723	38.2	77 - 116	28 - 42	WIND RIVER
30	WINKLEMAN	PHOSPHORIA	2600	25.7	74 - 111	27 - 40	WIND RIVER
31	GAS DRAW	MUDDY	7191	37.39	71 - 107	26 - 39	POWDER RIVER
32	BIG MUDDY	DAKOTA	4298	36.8	70 - 106	25 - 38	POWDER RIVER
33	GRASS CREEK	PHOSPHORIA	3632	24.5	68 - 102	24 - 37	BIGHORN
34	KITTY	MUDDY	9201	42	68 - 102	24 - 37	POWDER RIVER
35	GRASS CREEK	CURTIS	3717	24.3	66 - 100	24 - 36	BIGHORN

Table 1 (continued). Top 100 ranked reservoires for potentially miscible CO_2 flooding in Wyoming

Rank	Field name	Reservoir Name	Reservoir Depth ft	Oil Gravity API	Est. Total CO2 BCF	Est. Initial CO2 MMCF/D	Basin Name
36	SAND DUNES	MUDDY	12600	42	65 - 97	23 - 35	POWDER RIVER
37	STEAMBOAT BUTTE	NUGGET	4164	38.5	61 - 92	22 - 33	WIND RIVER
38	DRY PINEY	NUGGET	10988	52	59 - 89	21 - 32	OVERTHRUST BELT
39	BEAVER CREEK	TENSLEEP	10442	45	59 - 89	21 - 32	WIND RIVER
40	WHITNEY CANYON-CARTER CREEK	MADISON	11790	49.4	59 - 88	21 - 32	OVERTHRUST BELT
41	COYOTE CREEK	DAKOTA	6400	41	55 - 83	20 - 30	POWDER RIVER
42	GARLAND	TENSLEEP	4267	23	54 - 81	19 - 29	BIGHORN
43	RYCKMAN CREEK	NUGGET	5800	47.2	52 - 78	19 - 28	OVERTHRUST BELT
44	ROZET	MINNELUSA	8156	34	50 - 75	18 - 27	POWDER RIVER
45	SALT CREEK	SUNDANCE-3	3000	35	49 - 73	17 - 26	POWDER RIVER
46	STEAMBOAT BUTTE	PHOSPHORIA	6732	31.1	48 - 72	17 - 26	WIND RIVER
47	RENO	MINNELUSA	15006	36.5	48 - 72	17 - 26	POWDER RIVER
48	TIMBER CREEK	MINNELUSA	9360	25	47 - 71	17 - 25	POWDER RIVER
49	MEADOW CREEK	TENSLEEP	9060	29.7	46 - 70	17 - 25	POWDER RIVER
50	BIRCH CREEK	BEAR RIVER 7500	7512	46	44 - 67	16 - 24	GREATER GREEN RIVER
51	SCOTT	PARKMAN	6102	37	44 - 66	16 - 24	POWDER RIVER
52	LANCE CREEK	CONVERSE	4394	41.5	42 - 64	15 - 23	POWDER RIVER
53	DILLINGER RANCH	MINNELUSA	9132	37	42 - 63	15 - 23	POWDER RIVER
54	SUSSEX WEST	SHANNON	2914	39.6	41 - 61	15 - 22	POWDER RIVER
55	LUCKEY DITCH	DAKOTA	14400	43	41 - 61	14 - 22	GREATER GREEN RIVER
56	BLACK MOUNTAIN	TENSLEEP	3125	24.9	39 - 59	14 - 21	BIGHORN
57	RAVEN CREEK	MINNELUSA	8354	33.4	39 - 58	14 - 21	POWDER RIVER
58	BIG MUDDY	WALL CREEK	3069	35.6	39 - 58	14 - 21	POWDER RIVER
59	COLE CREEK	DAKOTA	7947	37	37 - 56	13 - 20	POWDER RIVER
60	MIKES DRAW	TEAPOT	7264	39	37 - 56	13 - 20	POWDER RIVER
61	WHITNEY CANYON-CARTER CREEK	MISSION CANYON	14226	49.4	35 - 53	13 - 19	OVERTHRUST BELT
62	HALVERSON	MINNELUSA	8489	24	35 - 53	12 - 19	POWDER RIVER
63	FINN-SHURLEY	TURNER	4886	38	35 - 52	12 - 19	POWDER RIVER
64	RECLUSE	MUDDY	7530	42.1	35 - 52	12 - 19	POWDER RIVER
65	STEWART	MINNELUSA	8024	22.5	34 - 52	12 - 19	POWDER RIVER
66	GEBO	EMBAR-TENSLEEP	4735	24.9	34 - 51	12 - 18	BIGHORN
67	SAGE SPRING CREEK	DAKOTA	7590	39.4	34 - 51	12 - 18	POWDER RIVER
68	ELK BASIN SOUTH	EMBAR-TENSLEEP	6846	28	33 - 50	12 - 18	BIGHORN
69	GARLAND	PHOSPHORIA	3060	24.3	33 - 49	12 - 18	BIGHORN
70	COLE CREEK SOUTH	DAKOTA	8309	35.4	32 - 49	11 - 17	POWDER RIVER

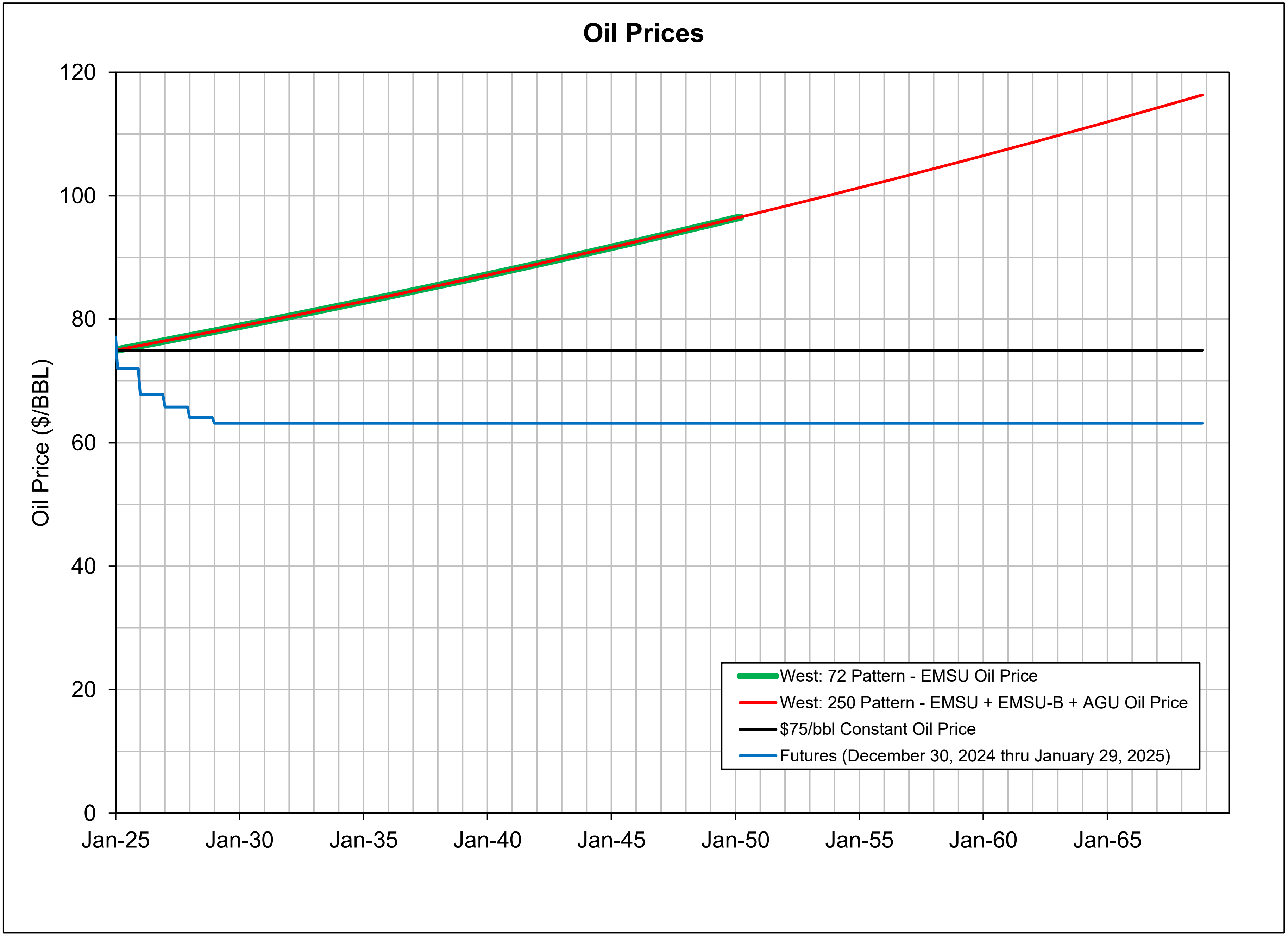
Table 1 (continued). Top 100 ranked reservoires for potentially miscible CO_2 flooding in Wyoming

Rank	Field name	Reservoir Name	Reservoir Depth ft	Oil Gravity API	Est. Total CO2 BCF	Est. Initial CO2 MMCF/D	Basin Name
71	PINE TREE	SHANNON	11720	38	31 - 47	11 - 17	POWDER RIVER
72	SLATTERY	MINNELUSA	6242	30	30 - 45	11 - 16	POWDER RIVER
73	SPRINGEN RANCH	MUDDY	7671	40.4	29 - 43	10 - 16	POWDER RIVER
74	WORLAND	TENSLEEP	9650	24.2	28 - 43	10 - 15	BIGHORN
75	ELK BASIN	BIG HORN	5460	23.3	28 - 42	10 - 15	BIGHORN
76	PATRICK DRAW	ALMOND	5067	43.4	27 - 41	10 - 15	GREATER GREEN RIVER
77	STANDARD DRAW	MESAVERDE	8968	59	27 - 40	9 - 14	GREATER GREEN RIVER
78	SANDBAR EAST	MINNELUSA	7034	23	27 - 40	9 - 14	POWDER RIVER
79	REEL	MINNELUSA	8429	33	26 - 40	9 - 14	POWDER RIVER
80	NOTCHES	TENSLEEP	2865	22.5	26 - 39	9 - 14	WIND RIVER
81	GARLAND	EMBAR	3060	24	26 - 39	9 - 14	BIGHORN
82	SILO	NIOBRARA	8402	35	26 - 39	9 - 14	DENVER-CHEYENNE
83	POWELL	DAKOTA	12955	46	25 - 38	9 - 14	POWDER RIVER
84	GOLDEN EAGLE	PHOSPHORIA	8890	48.8	25 - 38	9 - 14	BIGHORN
85	SKULL CREEK	NEWCASTLE	3170	34	25 - 37	9 - 13	POWDER RIVER
86	POWNALL RANCH	MINNELUSA	6222	259	24 - 37	9 - 13	POWDER RIVER
87	ROCK RIVER	MUDDY-DAKOTA-LAKOTA	2581	37	24 - 36	8 - 13	LARAMIE
88	POISON SPIDER WEST	CODY	10145	45	24 - 36	8 - 13	WIND RIVER
89	LITTLE MITCHELL CREEK	MINNELUSA	7330	26	24 - 36	8 - 13	POWDER RIVER
90	UTE	MUDDY	6382	41.1	23 - 35	8 - 13	POWDER RIVER
91	HENRY	DAKOTA	13393	52	23 - 35	8 - 12	GREATER GREEN RIVER
92	BONE PILE	MINNELUSA	8528	31.5	22 - 34	8 - 12	POWDER RIVER
93	ROZET	MUDDY	6935	35.4	22 - 33	8 - 12	POWDER RIVER
94	BIG SAND DRAW	PHOSPHORIA	6850	62.1	22 - 33	8 - 12	WIND RIVER
95	DONKEY CREEK	MINNELUSA	7845	27.7	22 - 33	8 - 12	POWDER RIVER
96	KAYE	TEAPOT	5512	39	22 - 33	8 - 12	POWDER RIVER
97	SUSSEX	TENSLEEP	9140	30.2	22 - 33	8 - 12	POWDER RIVER
98	GLENROCK SOUTH	MUDDY	6300	38.6	22 - 33	8 - 12	POWDER RIVER
99	GOOSEBERRY	PHOSPHORIA-TENSLEEP	5668	22.6	22 - 33	8 - 12	BIGHORN
100	HELDT DRAW	SHANNON	9400	35.6	22 - 33	8 - 12	POWDER RIVER

Table 2. Top 20 ranked reservoires for immiscible CO_2 flooding in Wyoming

Rank	Field Name	Reservoir Name	Reservoir Depth ft	Oil Gravity API	Est. Total CO2 BCF	Est. Initial CO2 MMCF/D	Basin Name
1	SALT CREEK	WALL CREEK-2	2200	37	852 - 1278	311 - 467	POWDER RIVER
2	OREGON BASIN	EMBAR	3525	21.6	677 - 1016	247 - 371	BIGHORN
3	GARLAND	MADISON	4424	20.5	230 - 345	84 - 126	BIGHORN
4	LITTLE BUFFALO BASIN	TENSLEEP	3348	19.6	137 - 206	50 - 75	BIGHORN
5	LITTLE BUFFALO BASIN	EMBAR	4781	19.6	99 - 149	36 - 54	BIGHORN
6	OREGON BASIN	MADISON	4465	22	93 - 140	34 - 51	BIGHORN
7	HAMILTON DOME	PHOSPHORIA	2400	26	82 - 123	30 - 45	BIGHORN
8	BYRON	EMBAR	5252	19.5	64 - 96	23 - 35	BIGHORN
9	PITCHFORK	TENSLEEP	3463	18.2	57 - 86	20 - 31	BIGHORN
10	NORTH FORK	TENSLEEP	6484	21.5	48 - 72	17 - 26	POWDER RIVER
11	BIRCH CREEK	MESAVERDE-3	1874	46	46 - 69	16 - 25	GREATER GREEN RIVER
12	SALT CREEK	WALL CREEK 1-2	2235	37	29 - 44	10 - 16	POWDER RIVER
13	TORCHLIGHT	MADISON	3550	20.5	28 - 42	10 - 15	BIGHORN
14	SPRING CREEK SOUTH	TENSLEEP	3796	15.3	27 - 40	9 - 14	BIGHORN
15	LITTLE BUFFALO BASIN	EMBAR-TENSLEEP	4781	19.6	26 - 39	9 - 14	BIGHORN
16	ROCKY POINT	MINNELUSA	5592	16.8	25 - 38	9 - 13	POWDER RIVER
17	FOURBEAR	DINWOODY-PHOSPH-TENSLEEP-DARWIN-MADISON	2900	13.5	24 - 37	9 - 13	BIGHORN
18	KUMMERFELD	MINNELUSA	5962	19	22 - 33	8 - 12	POWDER RIVER
19	ROZET WEST	MINNELUSA	8692	21	20 - 30	7 - 11	POWDER RIVER
20	LABARGE	MESAVERDE	1960	45.6	18 - 27	6 - 10	GREATER GREEN RIVER

REBUTTAL EXHIBIT F-23



REBUTTAL EXHIBIT F-24

	72 Pattern EMSU		250 Pattern EMSU + EMSU-B + AGU	
	PV-10 ($M)	PV-10 ($M)	PV-10 ($M)	PV-10 ($M)
West's Value	262,518		585,565	
	Porosity = 9.35% Oil Saturation = 10.39%	Porosity = 9.35% Oil Saturation = 10.39% CO2 Purchase = 1.5 $/MCF	Porosity = 9.35% Oil Saturation = 10.39%	Porosity = 9.35% Oil Saturation = 10.39% CO2 Purchase = 1.5 $/MCF
$75/bbl Constant Oil Price	-24,036	-66,562	-86,475	-175,852
Futures (December 30, 2024 thru January 29, 2025)	-84,277	-127,486	-214,962	-307,007

72 Pattern - EMSU

	PV-10 ($M)	PV-10 ($M)
West's Value	262,518	
	Porosity = 9.35% Oil Saturation = 10.39%	Porosity = 9.35% Oil Saturation = 10.39% CO2 Purchase = 1.5 $/MCF
$75/bbl Constant Oil Price	-24,036	-66,562
Futures (December 30, 2024 thru January 29, 2025)	-84,277	-127,486

EMSU
EMPIRE PETROLEUM CORPORATION

PROBABLE RESERVES 1/1/2025

$75/bbl Constant Oil Price

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 182,500	$ (182,500)	$ (182,500)	$ (158,862)
2027	540	540	459	$ 75.0	$ 34,409	1,186	16,416	$ 860	$ 178	$ 16,420	$ 3,899	$ 13,052	$ 20,497	$ 7,500	$ 5,552	$ (176,948)	$ (154,733)
2028	760	760	646	$ 75.0	$ 48,419	6,777	12,375	$ 1,210	$ 1,017	$ 12,415	$ 4,998	$ 28,779	$ 18,429	$ 75,000	$ (46,221)	$ (223,169)	$ (187,953)
2029	1,292	1,292	1,098	$ 75.0	$ 82,376	16,262	23,775	$ 2,059	$ 2,439	$ 23,779	$ 7,661	$ 46,438	$ 33,879	$ 15,000	$ 31,438	$ (191,731)	$ (167,866)
2030	1,417	1,417	1,205	$ 75.0	$ 90,361	26,140	18,456	$ 2,259	$ 3,921	$ 18,461	$ 8,287	$ 57,433	$ 30,669	$ 47,500	$ 9,933	$ (181,798)	$ (162,365)
2031	1,894	1,894	1,609	$ 75.0	$ 120,711	38,491	30,913	$ 3,018	$ 5,774	$ 30,919	$ 10,668	$ 70,333	$ 47,360	$ 22,500	$ 47,833	$ (133,965)	$ (137,471)
2032	2,042	2,042	1,735	$ 75.0	$ 130,152	51,704	25,907	$ 3,254	$ 7,756	$ 26,009	$ 11,408	$ 81,725	$ 45,173	$ -	$ 81,725	$ (52,239)	$ (98,582)
2033	1,736	1,736	1,476	$ 75.0	$ 110,664	65,944	12,853	$ 3,560	$ 9,892	$ 12,839	$ 9,880	$ 74,495	$ 32,610	$ -	$ 74,495	$ 22,255	$ (66,430)
2034	1,263	1,263	1,074	$ 75.0	$ 80,534	73,444	5,353	$ 4,550	$ 11,017	$ 5,355	$ 7,516	$ 52,096	$ 23,888	$ -	$ 52,096	$ 74,351	$ (46,038)
2035	776	776	660	$ 75.0	$ 49,483	63,835	3,288	$ 2,796	$ 9,575	$ 3,280	$ 5,081	$ 28,751	$ 17,936	$ -	$ 28,751	$ 103,102	$ (35,842)
2036	559	559	475	$ 75.0	$ 35,616	57,334	2,949	$ 2,012	$ 8,600	$ 2,987	$ 3,993	$ 18,023	$ 15,580	$ -	$ 18,023	$ 121,125	$ (30,062)
2037	372	372	317	$ 75.0	$ 23,739	43,716	2,249	$ 1,341	$ 6,557	$ 2,236	$ 3,062	$ 10,542	$ 11,856	$ -	$ 10,542	$ 131,667	$ (27,008)
2038	319	319	271	$ 75.0	$ 20,361	34,175	1,758	$ 1,150	$ 5,126	$ 1,760	$ 2,797	$ 9,527	$ 9,684	$ -	$ 9,527	$ 141,195	$ (24,506)
2039	125	125	106	$ 75.0	$ 7,986	17,087	879	$ 451	$ 2,563	$ 862	$ 1,826	$ 2,283	$ 5,251	$ -	$ 2,283	$ 143,478	$ (23,955)
2040	19	19	16	$ 75.0	$ 1,218	3,123	161	$ 69	$ 468	$ 162	$ 896	$ (376)	$ 1,525	$ -	$ (376)	$ 143,101	$ (24,036)
2041	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2042	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2043	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2044	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2045	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2046	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2047	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2048	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2049	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
2050	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,101	$ (24,036)
TOTAL	13,114	13,114	11,147		836,029	499,219	157,330	28,590	$ 74,883	$ 157,484	$ 81,971	$ 493,101	$ 314,338	$ 350,000	$ 143,101		

DISCOUNT FACTOR	10.0
GWI	100.00
NRI	85.00

NPV-10 (M$) $ (24,036)

DEVELOPMENT COST ($/BO)	$	31.40
LIFTING COST ($/BO)	$	28.20
NON-CO2 LIFTING COST ($/BO)	$	7.35

GROSS UTILIZATION (MCF/BO)	50.06
NET UTILIZATION (MCF/BO)	12.00

EMSU
EMPIRE PETROLEUM CORPORATION

PROBABLE RESERVES 1/1/2025

Futures (December 30, 2024 thru January 29, 2025)

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 182,500	$ (182,500)	$ (182,500)	$ (158,862)
2027	540	540	459	$ 65.8	$ 30,184	1,186	16,416	$ 755	$ 178	$ 16,420	$ 3,899	$ 8,932	$ 20,497	$ 7,500	$ 1,432	$ (181,068)	$ (157,939)
2028	760	760	646	$ 64.1	$ 41,356	6,777	12,375	$ 1,034	$ 1,017	$ 12,415	$ 4,998	$ 21,893	$ 18,429	$ 75,000	$ (53,107)	$ (234,175)	$ (196,037)
2029	1,292	1,292	1,098	$ 63.2	$ 69,394	16,262	23,775	$ 1,735	$ 2,439	$ 23,779	$ 7,661	$ 33,780	$ 33,879	$ 15,000	$ 18,780	$ (215,395)	$ (184,053)
2030	1,417	1,417	1,205	$ 63.2	$ 76,120	26,140	18,456	$ 1,903	$ 3,921	$ 18,461	$ 8,287	$ 43,548	$ 30,669	$ 47,500	$ (3,952)	$ (219,347)	$ (186,618)
2031	1,894	1,894	1,609	$ 63.2	$ 101,687	38,491	30,913	$ 2,542	$ 5,774	$ 30,919	$ 10,668	$ 51,785	$ 47,360	$ 22,500	$ 29,285	$ (190,062)	$ (171,461)
2032	2,042	2,042	1,735	$ 63.2	$ 109,640	51,704	25,907	$ 2,741	$ 7,756	$ 26,009	$ 11,408	$ 61,726	$ 45,173	$ -	$ 61,726	$ (128,336)	$ (142,094)
2033	1,736	1,736	1,476	$ 63.2	$ 93,223	65,944	12,853	$ 2,331	$ 9,892	$ 12,839	$ 9,880	$ 58,283	$ 32,610	$ -	$ 58,283	$ (70,053)	$ (116,953)
2034	1,263	1,263	1,074	$ 63.2	$ 67,842	73,444	5,353	$ 1,696	$ 11,017	$ 5,355	$ 7,516	$ 42,258	$ 23,888	$ -	$ 42,258	$ (27,795)	$ (100,411)
2035	776	776	660	$ 63.2	$ 41,684	63,835	3,288	$ 1,042	$ 9,575	$ 3,280	$ 5,081	$ 22,706	$ 17,936	$ -	$ 22,706	$ (5,089)	$ (92,357)
2036	559	559	475	$ 63.2	$ 30,003	57,334	2,949	$ 1,355	$ 8,600	$ 2,987	$ 3,993	$ 13,068	$ 15,580	$ -	$ 13,068	$ 7,978	$ (88,160)
2037	372	372	317	$ 63.2	$ 19,998	43,716	2,249	$ 1,130	$ 6,557	$ 2,236	$ 3,062	$ 7,013	$ 11,856	$ -	$ 7,013	$ 14,991	$ (86,130)
2038	319	319	271	$ 63.2	$ 17,152	34,175	1,758	$ 969	$ 5,126	$ 1,760	$ 2,797	$ 6,500	$ 9,684	$ -	$ 6,500	$ 21,491	$ (84,423)
2039	125	125	106	$ 63.2	$ 6,727	17,087	879	$ 380	$ 2,563	$ 862	$ 1,826	$ 1,096	$ 5,251	$ -	$ 1,096	$ 22,586	$ (84,157)
2040	19	19	16	$ 63.2	$ 1,026	3,123	161	$ 58	$ 468	$ 162	$ 896	$ (558)	$ 1,525	$ -	$ (558)	$ 22,029	$ (84,277)
2041	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2042	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2043	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2044	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2045	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2046	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2047	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2048	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2049	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
2050	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,029	$ (84,277)
TOTAL	13,114	13,114	11,147		706,037	499,219	157,330	19,670	$ 74,883	$ 157,484	$ 81,971	$ 372,029	$ 314,338	$ 350,000	$ 22,029		

DISCOUNT FACTOR	10.0						
GWI	100.00	NPV-10 (M$)	$ (84,277)	DEVELOPMENT COST ($/BO)	$ 31.40	GROSS UTILIZATION (MCF/BO)	50.06
NRI	85.00						
				LIFTING COST ($/BO)	$ 28.20	NET UTILIZATION (MCF/BO)	12.00
				NON-CO2 LIFTING COST ($/BO)	$ 7.35		

EMSU
EMPIRE PETROLEUM CORPORATION — **PROBABLE RESERVES 1/1/2025**

$75/bbl Constant Oil Price
CO2 Purchase = 1.5 $/MCF

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 182,500	$ (182,500)	$ (182,500)	$ (158,862)
2027	540	540	459	$ 75.0	$ 34,409	1,186	16,416	$ 860	$ 178	$ 24,630	$ 3,899	$ 4,842	$ 28,706	$ 7,500	$ (2,658)	$ (185,158)	$ (161,171)
2028	760	760	646	$ 75.0	$ 48,419	6,777	12,375	$ 1,210	$ 1,017	$ 18,621	$ 4,998	$ 22,574	$ 24,635	$ 75,000	$ (52,426)	$ (237,584)	$ (198,806)
2029	1,292	1,292	1,098	$ 75.0	$ 82,376	16,262	23,775	$ 2,059	$ 2,439	$ 35,665	$ 7,661	$ 34,551	$ 45,766	$ 15,000	$ 19,551	$ (218,033)	$ (186,368)
2030	1,417	1,417	1,205	$ 75.0	$ 90,361	26,140	18,456	$ 2,259	$ 3,921	$ 27,688	$ 8,287	$ 48,205	$ 39,897	$ 47,500	$ 705	$ (217,328)	$ (186,236)
2031	1,894	1,894	1,609	$ 75.0	$ 120,711	38,491	30,913	$ 3,018	$ 5,774	$ 46,375	$ 10,668	$ 54,878	$ 62,816	$ 22,500	$ 32,378	$ (184,950)	$ (169,483)
2032	2,042	2,042	1,735	$ 75.0	$ 130,152	51,704	25,907	$ 3,254	$ 7,756	$ 39,000	$ 11,408	$ 68,735	$ 58,164	$ -	$ 68,735	$ (116,215)	$ (136,793)
2033	1,736	1,736	1,476	$ 75.0	$ 110,664	65,944	12,853	$ 2,767	$ 9,892	$ 19,253	$ 9,880	$ 68,873	$ 39,024	$ -	$ 68,873	$ (47,342)	$ (107,100)
2034	1,263	1,263	1,074	$ 75.0	$ 80,534	73,444	5,353	$ 2,191	$ 11,017	$ 8,029	$ 7,516	$ 51,781	$ 26,562	$ -	$ 51,781	$ 4,439	$ (86,831)
2035	776	776	660	$ 75.0	$ 49,483	63,835	3,288	$ 2,796	$ 9,575	$ 4,923	$ 5,081	$ 27,107	$ 19,579	$ -	$ 27,107	$ 31,547	$ (77,216)
2036	559	559	475	$ 75.0	$ 35,616	57,334	2,949	$ 2,012	$ 8,600	$ 4,466	$ 3,993	$ 16,544	$ 17,060	$ -	$ 16,544	$ 48,090	$ (71,909)
2037	372	372	317	$ 75.0	$ 23,739	43,716	2,249	$ 1,341	$ 6,557	$ 3,359	$ 3,062	$ 9,420	$ 12,978	$ -	$ 9,420	$ 57,510	$ (69,181)
2038	319	319	271	$ 75.0	$ 20,361	34,175	1,758	$ 1,150	$ 5,126	$ 2,640	$ 2,797	$ 8,648	$ 10,563	$ -	$ 8,648	$ 66,158	$ (66,910)
2039	125	125	106	$ 75.0	$ 7,986	17,087	879	$ 451	$ 2,563	$ 1,299	$ 1,826	$ 1,846	$ 5,689	$ -	$ 1,846	$ 68,004	$ (66,464)
2040	19	19	16	$ 75.0	$ 1,218	3,123	161	$ 69	$ 468	$ 242	$ 896	$ (457)	$ 1,606	$ -	$ (457)	$ 67,547	$ (66,562)
2041	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2042	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2043	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2044	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2045	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2046	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2047	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2048	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2049	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
2050	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,547	$ (66,562)
TOTAL	13,114	13,114	11,147		836,029	499,219	157,330	25,438	$ 74,883	$ 236,190	$ 81,971	$ 417,547	$ 393,044	$ 350,000	$ 67,547		

DISCOUNT FACTOR	10.0						
GWI	100.00	NPV-10 (M$)	$ (66,562)	DEVELOPMENT COST ($/BO)	$ 31.40	GROSS UTILIZATION (MCF/BO)	50.06
NRI	85.00						
				LIFTING COST ($/BO)	$ 35.26	NET UTILIZATION (MCF/BO)	12.00
				NON-CO2 LIFTING COST ($/BO)	$ 7.35		

EMSU

EMPIRE PETROLEUM CORPORATION

PROBABLE RESERVES 1/1/2025

Futures (December 30, 2024 thru January 29, 2025)

CO_2 Purchase = 1.5 $/MCF

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 182,500	$ (182,500)	$ (182,500)	$ (158,862)
2027	540	540	459	$ 65.8	$ 30,184	1,186	16,416	$ 755	$ 178	$ 24,630	$ 3,899	$ 723	$ 28,706	$ 7,500	$ (6,777)	$ (189,277)	$ (164,377)
2028	760	760	646	$ 64.1	$ 41,356	6,777	12,375	$ 1,034	$ 1,017	$ 18,621	$ 4,998	$ 15,687	$ 24,635	$ 75,000	$ (59,313)	$ (248,590)	$ (206,890)
2029	1,292	1,292	1,098	$ 63.2	$ 69,394	16,262	23,775	$ 1,735	$ 2,439	$ 35,665	$ 7,661	$ 21,893	$ 45,766	$ 15,000	$ 6,893	$ (241,696)	$ (202,555)
2030	1,417	1,417	1,205	$ 63.2	$ 76,120	26,140	18,456	$ 1,903	$ 3,921	$ 27,688	$ 8,287	$ 34,320	$ 39,897	$ 47,500	$ (13,180)	$ (254,876)	$ (210,489)
2031	1,894	1,894	1,609	$ 63.2	$ 101,687	38,491	30,913	$ 2,542	$ 5,774	$ 46,375	$ 10,668	$ 36,329	$ 62,816	$ 22,500	$ 13,829	$ (241,047)	$ (203,473)
2032	2,042	2,042	1,735	$ 63.2	$ 109,640	51,704	25,907	$ 2,741	$ 7,756	$ 39,000	$ 11,408	$ 48,735	$ 58,164	$ -	$ 48,735	$ (192,311)	$ (180,305)
2033	1,736	1,736	1,476	$ 63.2	$ 93,223	65,944	12,853	$ 2,331	$ 9,892	$ 19,253	$ 9,880	$ 51,869	$ 39,024	$ -	$ 51,869	$ (140,443)	$ (157,953)
2034	1,263	1,263	1,074	$ 63.2	$ 67,842	73,444	5,353	$ 1,696	$ 11,017	$ 8,029	$ 7,516	$ 39,584	$ 26,562	$ -	$ 39,584	$ (100,859)	$ (142,458)
2035	776	776	660	$ 63.2	$ 41,684	63,835	3,288	$ 1,042	$ 9,575	$ 4,923	$ 5,081	$ 21,063	$ 19,579	$ -	$ 21,063	$ (79,796)	$ (134,986)
2036	559	559	475	$ 63.2	$ 30,003	57,334	2,949	$ 750	$ 8,600	$ 4,466	$ 3,993	$ 12,193	$ 17,060	$ -	$ 12,193	$ (67,603)	$ (131,072)
2037	372	372	317	$ 63.2	$ 19,998	43,716	2,249	$ 500	$ 6,557	$ 3,359	$ 3,062	$ 6,520	$ 12,978	$ -	$ 6,520	$ (61,084)	$ (129,186)
2038	319	319	271	$ 63.2	$ 17,152	34,175	1,758	$ 429	$ 5,126	$ 2,640	$ 2,797	$ 6,161	$ 10,563	$ -	$ 6,161	$ (54,923)	$ (127,567)
2039	125	125	106	$ 63.2	$ 6,727	17,087	879	$ 168	$ 2,563	$ 1,299	$ 1,826	$ 870	$ 5,689	$ -	$ 870	$ (54,052)	$ (127,355)
2040	19	19	16	$ 63.2	$ 1,026	3,123	161	$ 26	$ 468	$ 242	$ 896	$ (606)	$ 1,606	$ -	$ (606)	$ (54,658)	$ (127,486)
2041	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2042	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2043	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2044	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2045	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2046	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2047	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2048	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2049	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
2050	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,658)	$ (127,486)
TOTAL	13,114	13,114	11,147		706,037	499,219	157,330	17,651	$ 74,883	$ 236,190	$ 81,971	$ 295,342	$ 393,044	$ 350,000	$ (54,658)		

DISCOUNT FACTOR 10.0

GWI 100.00

NRI 85.00

NPV-10 (M$) $ (127,486)

DEVELOPMENT COST ($/BO) $ 31.40

LIFTING COST ($/BO) $ 35.26

NON-CO2 LIFTING COST ($/BO) $ 7.35

GROSS UTILIZATION (MCF/BO) 50.06

NET UTILIZATION (MCF/BO) 12.00

250 Pattern - EMSU + EMSU-B + AGU

	PV-10 ($M)	PV-10 ($M)
West's Value	585,565	
	Porosity = 9.35% Oil Saturation = 10.39%	Porosity = 9.35% Oil Saturation = 10.39% CO2 Purchase = 1.5 $/MCF
$75/bbl Constant Oil Price	-86,475	-175,852
Futures (December 30, 2024 thru January 29, 2025)	-214,962	-307,007

250 Pattern - EMSU + EMSU-B + AGU
EMPIRE PETROLEUM CORPORATION

PROBABLE RESERVES 1/1/2025

$75/bbl Constant Oil Price

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 166,375	$ (166,375)	$ (166,375)	$ (142,924)
2027	538	538	457	$ 75	$ 34,307	1,186	16,324	$ 858	$ 178	$ 16,327	$ 8,691	$ 8,253	$ 25,196	$ 4,125	$ 4,128	$ (162,247)	$ (139,820)
2028	740	740	629	$ 75	$ 47,180	6,733	11,781	$ 1,179	$ 1,010	$ 11,815	$ 9,700	$ 23,475	$ 22,525	$ 61,875	$ (38,400)	$ (200,647)	$ (166,812)
2029	1,233	1,233	1,048	$ 75	$ 78,599	15,950	22,354	$ 1,965	$ 2,393	$ 22,352	$ 12,165	$ 39,725	$ 36,909	$ 8,250	$ 31,475	$ (169,172)	$ (146,752)
2030	1,297	1,297	1,102	$ 75	$ 82,663	25,108	15,932	$ 2,067	$ 3,766	$ 15,937	$ 12,483	$ 48,410	$ 32,187	$ 184,250	$ (135,840)	$ (305,012)	$ (224,952)
2031	1,694	1,694	1,440	$ 75	$ 107,989	36,171	27,122	$ 2,700	$ 5,426	$ 27,126	$ 14,470	$ 58,268	$ 47,021	$ 20,625	$ 37,643	$ (267,369)	$ (205,137)
2032	1,754	1,754	1,491	$ 75	$ 111,812	47,420	21,527	$ 2,795	$ 7,113	$ 21,617	$ 14,770	$ 65,517	$ 43,499	$ 82,500	$ (16,983)	$ (284,352)	$ (213,047)
2033	2,224	2,224	1,890	$ 75	$ 141,771	60,929	33,554	$ 3,544	$ 9,139	$ 33,560	$ 17,119	$ 78,408	$ 59,819	$ 37,125	$ 41,283	$ (243,069)	$ (195,274)
2034	2,363	2,363	2,009	$ 75	$ 150,655	75,018	29,041	$ 3,766	$ 11,253	$ 29,063	$ 17,816	$ 88,757	$ 58,132	$ 202,125	$ (113,368)	$ (356,437)	$ (238,982)
2035	2,792	2,792	2,373	$ 75	$ 177,972	80,788	41,511	$ 4,449	$ 12,118	$ 41,515	$ 19,959	$ 99,931	$ 73,592	$ 30,250	$ 69,681	$ (286,756)	$ (214,476)
2036	2,933	2,933	2,493	$ 75	$ 186,975	92,474	35,662	$ 4,674	$ 13,871	$ 35,823	$ 20,665	$ 111,942	$ 70,359	$ 210,375	$ (98,433)	$ (385,189)	$ (245,580)
2037	3,333	3,333	2,833	$ 75	$ 212,468	100,234	47,419	$ 5,312	$ 15,035	$ 47,422	$ 22,664	$ 122,035	$ 85,121	$ 31,625	$ 90,410	$ (294,779)	$ (219,469)
2038	3,446	3,446	2,929	$ 75	$ 219,695	112,816	41,585	$ 5,492	$ 16,922	$ 41,618	$ 23,231	$ 132,431	$ 81,771	$ 45,375	$ 87,056	$ (207,723)	$ (196,614)
2039	3,285	3,285	2,792	$ 75	$ 209,404	119,829	36,397	$ 5,235	$ 17,974	$ 36,410	$ 22,424	$ 127,361	$ 76,808	$ 33,000	$ 94,361	$ (113,362)	$ (174,257)
2040	3,199	3,199	2,719	$ 75	$ 203,929	127,011	35,325	$ 5,098	$ 19,052	$ 35,507	$ 21,994	$ 122,278	$ 76,553	$ 41,250	$ 81,028	$ (32,334)	$ (156,878)
2041	3,100	3,100	2,635	$ 75	$ 197,615	125,487	37,122	$ 8,077	$ 18,823	$ 37,149	$ 21,499	$ 112,066	$ 77,472	$ 41,250	$ 70,816	$ 38,483	$ (143,096)
2042	3,161	3,161	2,687	$ 75	$ 201,521	128,455	37,803	$ 11,386	$ 19,268	$ 37,843	$ 21,806	$ 111,218	$ 78,917	$ 12,375	$ 98,843	$ 137,326	$ (125,797)
2043	2,796	2,796	2,377	$ 75	$ 178,271	123,616	26,134	$ 10,072	$ 18,542	$ 26,108	$ 19,982	$ 103,566	$ 64,632	$ -	$ 103,566	$ 240,892	$ (109,295)
2044	2,126	2,126	1,807	$ 75	$ 135,510	119,417	12,185	$ 7,656	$ 17,913	$ 12,272	$ 16,628	$ 81,041	$ 46,812	$ -	$ 81,041	$ 321,934	$ (97,584)
2045	1,331	1,331	1,131	$ 75	$ 84,834	100,083	5,435	$ 4,793	$ 15,012	$ 5,421	$ 12,654	$ 46,953	$ 33,087	$ -	$ 46,953	$ 368,887	$ (91,429)
2046	847	847	720	$ 75	$ 54,024	80,407	4,136	$ 3,052	$ 12,061	$ 4,139	$ 10,237	$ 24,534	$ 26,438	$ -	$ 24,534	$ 393,421	$ (88,518)
2047	576	576	490	$ 75	$ 36,750	64,100	3,297	$ 2,076	$ 9,615	$ 3,297	$ 8,882	$ 12,879	$ 21,795	$ -	$ 12,879	$ 406,300	$ (87,135)
2048	422	422	359	$ 75	$ 26,912	47,880	2,463	$ 1,521	$ 7,182	$ 2,490	$ 8,111	$ 7,609	$ 17,783	$ -	$ 7,609	$ 413,908	$ (86,396)
2049	262	262	223	$ 75	$ 16,710	30,098	1,548	$ 944	$ 4,515	$ 1,543	$ 7,311	$ 2,398	$ 13,368	$ -	$ 2,398	$ 416,307	$ (86,182)
2050	86	86	73	$ 75	$ 5,462	12,317	634	$ 309	$ 1,848	$ 628	$ 6,428	$ (3,750)	$ 8,904	$ -	$ (3,750)	$ 412,556	$ (86,475)
2051	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2052	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2053	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2054	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2055	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2056	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2057	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2058	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2059	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2060	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2061	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2062	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2063	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2064	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2065	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2066	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2067	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
2068	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,556	$ (86,475)
TOTAL	45,538	45,538	38,707		2,903,028	1,733,526	546,292	99,022	$ 260,029	$ 546,982	$ 371,688	$ 1,625,306	$ 1,178,700	$ 1,212,750	$ 412,556		

DISCOUNT FACTOR 10.0
GWI 100.00
NRI 85.00

NPV-10 (M$) $ (86,475)

DEVELOPMENT COST ($/BO) $ 31.33
LIFTING COST ($/BO) $ 30.45
NON-CO2 LIFTING COST ($/BO) $ 9.60

GROSS UTILIZATION (MCF/BO) 50.06
NET UTILIZATION (MCF/BO) 12.00

250 Pattern - EMSU + EMSU-B + AGU
EMPIRE PETROLEUM CORPORATION

PROBABLE RESERVES 1/1/2025

FUTURES (DECEMBER 30, 2024 THRU JANUARY 29, 2025)

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 166,375	$ (166,375)	$ (166,375)	$ (142,924)
2027	538	538	457	$ 65.79	$ 30,094	1,186	16,324	$ 752	$ 178	$ 16,327	$ 8,691	$ 4,146	$ 25,196	$ 4,125	$ 21	$ (166,354)	$ (143,017)
2028	740	740	629	$ 64.06	$ 40,298	6,733	11,781	$ 1,007	$ 1,010	$ 11,815	$ 9,700	$ 16,765	$ 22,525	$ 61,875	$ (45,110)	$ (211,464)	$ (174,764)
2029	1,233	1,233	1,048	$ 63.18	$ 66,211	15,950	22,354	$ 1,655	$ 2,393	$ 22,352	$ 12,165	$ 27,647	$ 36,909	$ 8,250	$ 19,397	$ (192,067)	$ (162,437)
2030	1,297	1,297	1,102	$ 63.18	$ 69,635	25,108	15,932	$ 1,741	$ 3,766	$ 15,937	$ 12,483	$ 35,708	$ 32,187	$ 184,250	$ (148,542)	$ (340,609)	$ (248,019)
2031	1,694	1,694	1,440	$ 63.18	$ 90,970	36,171	27,122	$ 2,274	$ 5,426	$ 27,126	$ 14,470	$ 41,675	$ 47,021	$ 20,625	$ 21,050	$ (319,559)	$ (236,918)
2032	1,754	1,754	1,491	$ 63.18	$ 94,190	47,420	21,527	$ 2,355	$ 7,113	$ 21,617	$ 14,770	$ 48,336	$ 43,499	$ 82,500	$ (34,164)	$ (353,723)	$ (253,008)
2033	2,224	2,224	1,890	$ 63.18	$ 119,428	60,929	33,554	$ 2,986	$ 9,139	$ 33,560	$ 17,119	$ 56,624	$ 59,819	$ 37,125	$ 19,499	$ (334,225)	$ (244,608)
2034	2,363	2,363	2,009	$ 63.18	$ 126,912	75,018	29,041	$ 3,173	$ 11,253	$ 29,063	$ 17,816	$ 65,607	$ 58,132	$ 202,125	$ (136,518)	$ (470,743)	$ (297,343)
2035	2,792	2,792	2,373	$ 63.18	$ 149,924	80,788	41,511	$ 3,748	$ 12,118	$ 41,515	$ 19,959	$ 72,584	$ 73,592	$ 30,250	$ 42,334	$ (428,409)	$ (282,483)
2036	2,933	2,933	2,493	$ 63.18	$ 157,508	92,474	35,662	$ 3,938	$ 13,871	$ 35,823	$ 20,665	$ 83,211	$ 70,359	$ 210,375	$ (127,164)	$ (555,573)	$ (322,768)
2037	3,333	3,333	2,833	$ 63.18	$ 178,983	100,234	47,419	$ 4,475	$ 15,035	$ 47,422	$ 22,664	$ 89,387	$ 85,121	$ 31,625	$ 57,762	$ (497,811)	$ (306,094)
2038	3,446	3,446	2,929	$ 63.18	$ 185,071	112,816	41,585	$ 4,627	$ 16,922	$ 41,618	$ 23,231	$ 98,673	$ 81,771	$ 45,375	$ 53,298	$ (444,513)	$ (292,080)
2039	3,285	3,285	2,792	$ 63.18	$ 176,402	119,829	36,397	$ 4,410	$ 17,974	$ 36,410	$ 22,424	$ 95,184	$ 76,808	$ 33,000	$ 62,184	$ (382,329)	$ (277,352)
2040	3,199	3,199	2,719	$ 63.18	$ 171,790	127,011	35,325	$ 4,295	$ 19,052	$ 35,507	$ 21,994	$ 90,943	$ 76,553	$ 41,250	$ 49,693	$ (332,636)	$ (266,698)
2041	3,100	3,100	2,635	$ 63.18	$ 166,471	125,487	37,122	$ 4,162	$ 18,823	$ 37,149	$ 21,499	$ 84,838	$ 77,472	$ 41,250	$ 43,588	$ (289,049)	$ (258,220)
2042	3,161	3,161	2,687	$ 63.18	$ 169,761	128,455	37,803	$ 4,244	$ 19,268	$ 37,843	$ 21,806	$ 86,600	$ 78,917	$ 12,375	$ 74,225	$ (214,823)	$ (245,247)
2043	2,796	2,796	2,377	$ 63.18	$ 150,175	123,616	26,134	$ 3,754	$ 18,542	$ 26,108	$ 19,982	$ 81,789	$ 64,632	$ -	$ 81,789	$ (133,035)	$ (232,218)
2044	2,126	2,126	1,807	$ 63.18	$ 114,154	119,417	12,185	$ 2,854	$ 17,913	$ 12,272	$ 16,628	$ 64,488	$ 46,812	$ -	$ 64,488	$ (68,547)	$ (222,898)
2045	1,331	1,331	1,131	$ 63.18	$ 71,464	100,083	5,435	$ 1,787	$ 15,012	$ 5,421	$ 12,654	$ 36,590	$ 33,087	$ -	$ 36,590	$ (31,957)	$ (218,101)
2046	847	847	720	$ 63.18	$ 45,510	80,407	4,136	$ 1,138	$ 12,061	$ 4,139	$ 10,237	$ 17,935	$ 26,438	$ -	$ 17,935	$ (14,023)	$ (215,971)
2047	576	576	490	$ 63.18	$ 30,958	64,100	3,297	$ 774	$ 9,615	$ 3,297	$ 8,882	$ 8,390	$ 21,795	$ -	$ 8,390	$ (5,633)	$ (215,070)
2048	422	422	359	$ 63.18	$ 22,671	47,880	2,463	$ 567	$ 7,182	$ 2,490	$ 8,111	$ 4,321	$ 17,783	$ -	$ 4,321	$ (1,312)	$ (214,649)
2049	262	262	223	$ 63.18	$ 14,077	30,098	1,548	$ 352	$ 4,515	$ 1,543	$ 7,311	$ 357	$ 13,368	$ -	$ 357	$ (955)	$ (214,615)
2050	86	86	73	$ 63.18	$ 4,601	12,317	634	$ 115	$ 1,848	$ 628	$ 6,428	$ (4,418)	$ 8,904	$ -	$ (4,418)	$ (5,373)	$ (214,962)
2051	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2052	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2053	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2054	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2055	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2056	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2057	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2058	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2059	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2060	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2061	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2062	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2063	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2064	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2065	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2066	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2067	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
2068	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,373)	$ (214,962)
TOTAL	45,538	45,538	38,707		2,447,259	1,733,526	546,292	61,181	$ 260,029	$ 546,982	$ 371,688	$ 1,207,377	$ 1,178,700	$ 1,212,750	$ (5,373)		

DISCOUNT FACTOR	10.0					
GWI	100.00	NPV-10 (M$)	$ (214,962)	DEVELOPMENT COST ($/BO)	$ 31.33	GROSS UTILIZATION (MCF/BO) 50.06
NRI	85.00					
				LIFTING COST ($/BO)	$ 30.45	NET UTILIZATION (MCF/BO) 12.00
				NON-CO2 LIFTING COST ($/BO)	$ 9.60	

250 Pattern - EMSU + EMSU-B + AGU
EMPIRE PETROLEUM CORPORATION

PROBABLE RESERVES 1/1/2025

$75/bbl Constant Oil Price
CO2 Purchase = 1.5 $/MCF

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 166,375	$ (166,375)	$ (166,375)	$ (142,924)
2027	538	538	457	$ 75.0	$ 34,307	1,186	16,324	$ 858	$ 178	$ 24,490	$ 8,691	$ 90	$ 33,359	$ 4,125	$ (4,035)	$ (170,410)	$ (146,223)
2028	740	740	629	$ 75.0	$ 47,180	6,733	11,781	$ 1,179	$ 1,010	$ 17,720	$ 9,700	$ 17,570	$ 28,430	$ 61,875	$ (44,305)	$ (214,715)	$ (177,420)
2029	1,233	1,233	1,048	$ 75.0	$ 78,599	15,950	22,354	$ 1,965	$ 2,393	$ 33,525	$ 12,165	$ 28,551	$ 48,082	$ 8,250	$ 20,301	$ (194,413)	$ (164,553)
2030	1,297	1,297	1,102	$ 75.0	$ 82,663	25,108	15,932	$ 2,067	$ 3,766	$ 23,903	$ 12,483	$ 40,443	$ 40,153	$ 184,250	$ (143,807)	$ (338,220)	$ (247,392)
2031	1,694	1,694	1,440	$ 75.0	$ 107,989	36,171	27,122	$ 2,700	$ 5,426	$ 40,685	$ 14,470	$ 44,709	$ 60,580	$ 20,625	$ 24,084	$ (314,135)	$ (234,727)
2032	1,754	1,754	1,491	$ 75.0	$ 111,812	47,420	21,527	$ 2,795	$ 7,113	$ 32,413	$ 14,770	$ 54,721	$ 54,295	$ 82,500	$ (27,779)	$ (341,914)	$ (247,783)
2033	2,224	2,224	1,890	$ 75.0	$ 141,771	60,929	33,554	$ 3,544	$ 9,139	$ 50,335	$ 17,119	$ 61,633	$ 76,594	$ 37,125	$ 24,508	$ (317,406)	$ (237,251)
2034	2,363	2,363	2,009	$ 75.0	$ 150,655	75,018	29,041	$ 3,766	$ 11,253	$ 43,590	$ 17,816	$ 74,230	$ 72,659	$ 202,125	$ (127,895)	$ (445,301)	$ (286,628)
2035	2,792	2,792	2,373	$ 75.0	$ 177,972	80,788	41,511	$ 4,449	$ 12,118	$ 62,272	$ 19,959	$ 79,174	$ 94,349	$ 30,250	$ 48,924	$ (396,377)	$ (269,462)
2036	2,933	2,933	2,493	$ 75.0	$ 186,975	92,474	35,662	$ 4,674	$ 13,871	$ 53,710	$ 20,665	$ 94,055	$ 88,246	$ 210,375	$ (116,320)	$ (512,697)	$ (306,287)
2037	3,333	3,333	2,833	$ 75.0	$ 212,468	100,234	47,419	$ 5,312	$ 15,035	$ 71,132	$ 22,664	$ 98,326	$ 108,831	$ 31,625	$ 66,701	$ (445,996)	$ (287,045)
2038	3,446	3,446	2,929	$ 75.0	$ 219,695	112,816	41,585	$ 5,492	$ 16,922	$ 62,419	$ 23,231	$ 111,630	$ 102,572	$ 45,375	$ 66,255	$ (379,741)	$ (269,641)
2039	3,285	3,285	2,792	$ 75.0	$ 209,404	119,829	36,397	$ 5,235	$ 17,974	$ 54,613	$ 22,424	$ 109,157	$ 95,011	$ 33,000	$ 76,157	$ (303,584)	$ (251,605)
2040	3,199	3,199	2,719	$ 75.0	$ 203,929	127,011	35,325	$ 5,098	$ 19,052	$ 53,228	$ 21,994	$ 104,557	$ 94,274	$ 41,250	$ 63,307	$ (240,277)	$ (238,026)
2041	3,100	3,100	2,635	$ 75.0	$ 197,615	125,487	37,122	$ 4,940	$ 18,823	$ 55,723	$ 21,499	$ 96,629	$ 96,045	$ 41,250	$ 55,379	$ (184,897)	$ (227,257)
2042	3,161	3,161	2,687	$ 75.0	$ 201,521	128,455	37,803	$ 5,038	$ 19,268	$ 56,758	$ 21,806	$ 98,651	$ 97,831	$ 12,375	$ 86,276	$ (98,621)	$ (212,167)
2043	2,796	2,796	2,377	$ 75.0	$ 178,271	123,616	26,134	$ 4,457	$ 18,542	$ 39,161	$ 19,982	$ 96,128	$ 77,686	$ -	$ 96,128	$ (2,493)	$ (196,859)
2044	2,126	2,126	1,807	$ 75.0	$ 135,510	119,417	12,185	$ 7,238	$ 17,913	$ 18,378	$ 16,628	$ 75,353	$ 52,919	$ -	$ 75,353	$ 72,860	$ (185,970)
2045	1,331	1,331	1,131	$ 75.0	$ 84,834	100,083	5,435	$ 4,793	$ 15,012	$ 8,136	$ 12,654	$ 44,238	$ 35,802	$ -	$ 44,238	$ 117,098	$ (180,172)
2046	847	847	720	$ 75.0	$ 54,024	80,407	4,136	$ 3,052	$ 12,061	$ 6,208	$ 10,237	$ 22,466	$ 28,506	$ -	$ 22,466	$ 139,564	$ (177,505)
2047	576	576	490	$ 75.0	$ 36,750	64,100	3,297	$ 2,076	$ 9,615	$ 4,946	$ 8,882	$ 11,230	$ 23,443	$ -	$ 11,230	$ 150,795	$ (176,299)
2048	422	422	359	$ 75.0	$ 26,912	47,880	2,463	$ 1,521	$ 7,182	$ 3,725	$ 8,111	$ 6,374	$ 19,018	$ -	$ 6,374	$ 157,168	$ (175,679)
2049	262	262	223	$ 75.0	$ 16,710	30,098	1,548	$ 944	$ 4,515	$ 2,316	$ 7,311	$ 1,625	$ 14,141	$ -	$ 1,625	$ 158,793	$ (175,533)
2050	86	86	73	$ 75.0	$ 5,462	12,317	634	$ 309	$ 1,848	$ 944	$ 6,428	$ (4,066)	$ 9,220	$ -	$ (4,066)	$ 154,727	$ (175,852)
2051	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2052	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2053	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2054	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2055	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2056	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2057	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2058	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2059	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2060	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2061	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2062	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2063	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2064	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2065	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2066	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2067	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
2068	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154,727	$ (175,852)
TOTAL	45,538	45,538	38,707		2,903,028	1,733,526	546,292	83,504	$ 260,029	$ 820,330	$ 371,688	$ 1,367,477	$ 1,452,047	$ 1,212,750	$ 154,727		

DISCOUNT FACTOR	10.0
GWI	100.00
NRI	85.00
NPV-10 (M$)	$ (175,852)
DEVELOPMENT COST ($/BO)	$ 31.33
LIFTING COST ($/BO)	$ 37.51
NON-CO2 LIFTING COST ($/BO)	$ 9.60
GROSS UTILIZATION (MCF/BO)	50.06
NET UTILIZATION (MCF/BO)	12.00

250 Pattern - EMSU + EMSU-B + AGU
EMPIRE PETROLEUM CORPORATION

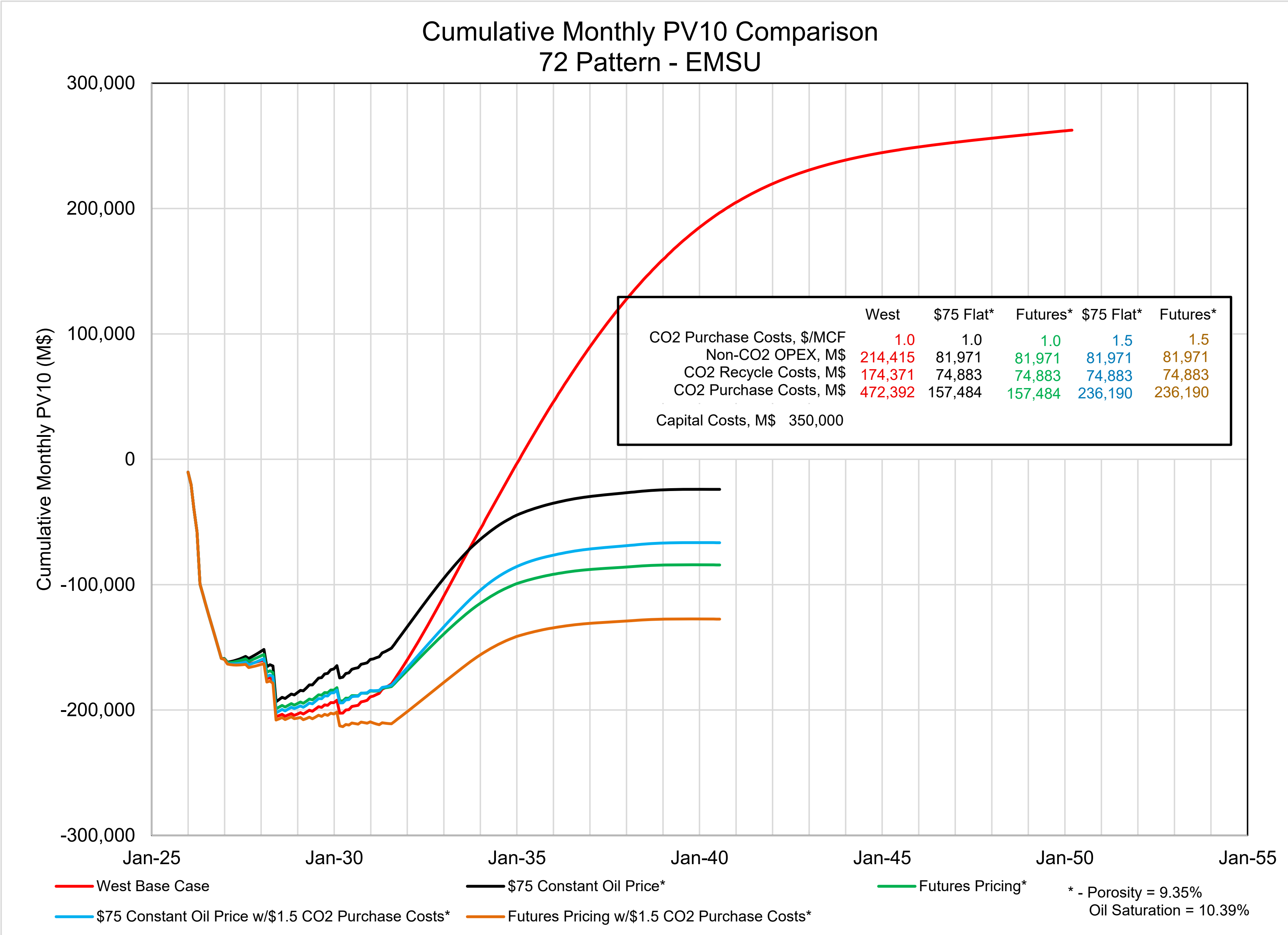
PROBABLE RESERVES 1/1/2025

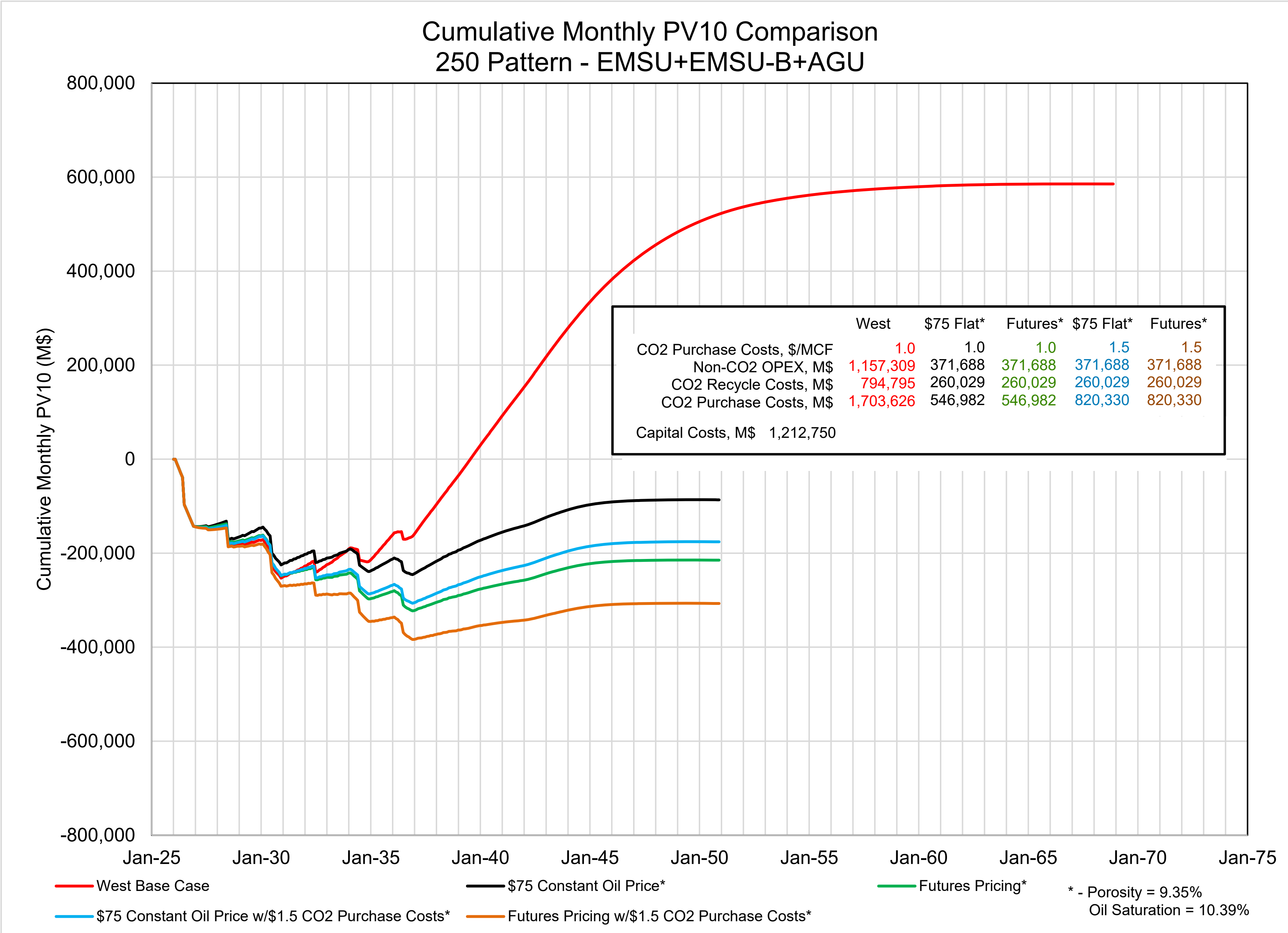
Futures (December 30, 2024 thru January 29, 2025)
CO2 Purchase = 1.5 $/MCF

YEAR	100% OIL (MBBL)	GROSS OIL (MBBL)	NET OIL (MBBL)	OIL PRICE ($/BBL)	TOTAL NET SALES (M$)	GROSS CO2 PROD (MMCF)	GROSS CO2 PURCHASED (MMCF)	TAXES (M$)	CO2 REC COST (M$)	CO2 PURCH COST (M$)	NON-CO2 LOE (M$)	OPERATING CASHFLOW (M$)	TOTAL GWI OPEX (M$)	NET CAPITAL (M$)	CASH FLOW BTAX (M$)	CUMULATIVE CASH FLOW (M$)	CUM PV DISC BTAX (M$)
2025	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 166,375	$ (166,375)	$ (166,375)	$ (142,924)
2027	538	538	457	$ 65.79	$ 30,094	1,186	16,324	$ 752	$ 178	$ 24,490	$ 8,691	$ (4,017)	$ 33,359	$ 4,125	$ (8,142)	$ (174,517)	$ (149,420)
2028	740	740	629	$ 64.06	$ 40,298	6,733	11,781	$ 1,007	$ 1,010	$ 17,720	$ 9,700	$ 10,860	$ 28,430	$ 61,875	$ (51,015)	$ (225,532)	$ (185,372)
2029	1,233	1,233	1,048	$ 63.18	$ 66,211	15,950	22,354	$ 1,655	$ 2,393	$ 33,525	$ 12,165	$ 16,474	$ 48,082	$ 8,250	$ 8,224	$ (217,308)	$ (180,238)
2030	1,297	1,297	1,102	$ 63.18	$ 69,635	25,108	15,932	$ 1,741	$ 3,766	$ 23,903	$ 12,483	$ 27,741	$ 40,153	$ 184,250	$ (156,509)	$ (373,817)	$ (270,459)
2031	1,694	1,694	1,440	$ 63.18	$ 90,970	36,171	27,122	$ 2,274	$ 5,426	$ 40,685	$ 14,470	$ 28,116	$ 60,580	$ 20,625	$ 7,491	$ (366,326)	$ (266,507)
2032	1,754	1,754	1,491	$ 63.18	$ 94,190	47,420	21,527	$ 2,355	$ 7,113	$ 32,413	$ 14,770	$ 37,540	$ 54,295	$ 82,500	$ (44,960)	$ (411,286)	$ (287,743)
2033	2,224	2,224	1,890	$ 63.18	$ 119,428	60,929	33,554	$ 2,986	$ 9,139	$ 50,335	$ 17,119	$ 39,849	$ 76,594	$ 37,125	$ 2,724	$ (408,562)	$ (286,585)
2034	2,363	2,363	2,009	$ 63.18	$ 126,912	75,018	29,041	$ 3,173	$ 11,253	$ 43,590	$ 17,816	$ 51,081	$ 72,659	$ 202,125	$ (151,044)	$ (559,607)	$ (344,989)
2035	2,792	2,792	2,373	$ 63.18	$ 149,924	80,788	41,511	$ 3,748	$ 12,118	$ 62,272	$ 19,959	$ 51,827	$ 94,349	$ 30,250	$ 21,577	$ (538,030)	$ (337,468)
2036	2,933	2,933	2,493	$ 63.18	$ 157,508	92,474	35,662	$ 3,938	$ 13,871	$ 53,710	$ 20,665	$ 65,324	$ 88,246	$ 210,375	$ (145,051)	$ (683,080)	$ (383,475)
2037	3,333	3,333	2,833	$ 63.18	$ 178,983	100,234	47,419	$ 4,475	$ 15,035	$ 71,132	$ 22,664	$ 65,678	$ 108,831	$ 31,625	$ 34,053	$ (649,028)	$ (373,671)
2038	3,446	3,446	2,929	$ 63.18	$ 185,071	112,816	41,585	$ 4,627	$ 16,922	$ 62,419	$ 23,231	$ 77,872	$ 102,572	$ 45,375	$ 32,497	$ (616,531)	$ (365,106)
2039	3,285	3,285	2,792	$ 63.18	$ 176,402	119,829	36,397	$ 4,410	$ 17,974	$ 54,613	$ 22,424	$ 76,980	$ 95,011	$ 33,000	$ 43,980	$ (572,550)	$ (354,700)
2040	3,199	3,199	2,719	$ 63.18	$ 171,790	127,011	35,325	$ 4,295	$ 19,052	$ 53,228	$ 21,994	$ 73,221	$ 94,274	$ 41,250	$ 31,971	$ (540,579)	$ (347,846)
2041	3,100	3,100	2,635	$ 63.18	$ 166,471	125,487	37,122	$ 4,162	$ 18,823	$ 55,723	$ 21,499	$ 66,264	$ 96,045	$ 41,250	$ 25,014	$ (515,565)	$ (342,975)
2042	3,161	3,161	2,687	$ 63.18	$ 169,761	128,455	37,803	$ 4,244	$ 19,268	$ 56,758	$ 21,806	$ 67,686	$ 97,831	$ 12,375	$ 55,311	$ (460,255)	$ (333,327)
2043	2,796	2,796	2,377	$ 63.18	$ 150,175	123,616	26,134	$ 3,754	$ 18,542	$ 39,161	$ 19,982	$ 68,735	$ 77,686	$ -	$ 68,735	$ (391,520)	$ (322,387)
2044	2,126	2,126	1,807	$ 63.18	$ 114,154	119,417	12,185	$ 2,854	$ 17,913	$ 18,378	$ 16,628	$ 58,381	$ 52,919	$ -	$ 58,381	$ (333,139)	$ (313,953)
2045	1,331	1,331	1,131	$ 63.18	$ 71,464	100,083	5,435	$ 1,787	$ 15,012	$ 8,136	$ 12,654	$ 33,875	$ 35,802	$ -	$ 33,875	$ (299,263)	$ (309,512)
2046	847	847	720	$ 63.18	$ 45,510	80,407	4,136	$ 1,138	$ 12,061	$ 6,208	$ 10,237	$ 15,866	$ 28,506	$ -	$ 15,866	$ (283,397)	$ (307,626)
2047	576	576	490	$ 63.18	$ 30,958	64,100	3,297	$ 774	$ 9,615	$ 4,946	$ 8,882	$ 6,741	$ 23,443	$ -	$ 6,741	$ (276,656)	$ (306,901)
2048	422	422	359	$ 63.18	$ 22,671	47,880	2,463	$ 567	$ 7,182	$ 3,725	$ 8,111	$ 3,086	$ 19,018	$ -	$ 3,086	$ (273,570)	$ (306,601)
2049	262	262	223	$ 63.18	$ 14,077	30,098	1,548	$ 352	$ 4,515	$ 2,316	$ 7,311	$ (416)	$ 14,141	$ -	$ (416)	$ (273,986)	$ (306,634)
2050	86	86	73	$ 63.18	$ 4,601	12,317	634	$ 115	$ 1,848	$ 944	$ 6,428	$ (4,734)	$ 9,220	$ -	$ (4,734)	$ (278,720)	$ (307,007)
2051	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2052	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2053	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2054	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2055	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2056	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2057	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2058	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2059	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2060	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2061	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2062	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2063	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2064	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2065	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2066	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2067	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
2068	-	-	-	$ -	$ -	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (278,720)	$ (307,007)
TOTAL	45,538	45,538	38,707		2,447,259	1,733,526	546,292	61,181	$ 260,029	$ 820,330	$ 371,688	$ 934,030	$ 1,452,047	$ 1,212,750	$ (278,720)		

DISCOUNT FACTOR	10.0						
GWI	100.00	NPV-10 (M$)	$ (307,007)	DEVELOPMENT COST ($/BO)	$ 31.33	GROSS UTILIZATION (MCF/BO)	50.06
NRI	85.00						
				LIFTING COST ($/BO)	$ 37.51	NET UTILIZATION (MCF/BO)	12.00
				NON-CO2 LIFTING COST ($/BO)	$ 9.60		

REBUTTAL EXHIBIT F-25




Cumulative Monthly PV10 Comparison
250 Pattern - EMSU+EMSU-B+AGU
Cumulative Monthly PV10 (M$)
800,000
600,000
400,000
200,000
0
-200,000
-400,000
-600,000
-800,000
Jan-25
Jan-30
Jan-35
Jan-40
Jan-45
Jan-50
Jan-55
Jan-60
Jan-65
Jan-70
Jan-75
West
$75 Flat*
Futures*
$75 Flat*
Futures*
CO2 Purchase Costs, $/MCF 1.0 1.0 1.0 1.5 1.5
Non-CO2 OPEX, M$ 1,157,309 371,688 371,688 371,688 371,688
CO2 Recycle Costs, M$ 794,795 260,029 260,029 260,029 260,029
CO2 Purchase Costs, M$ 1,703,626 546,982 546,982 820,330 820,330
Capital Costs, M$ 1,212,750
West Base Case
$75 Constant Oil Price*
Futures Pricing*
$75 Constant Oil Price w/$1.5 CO2 Purchase Costs*
Futures Pricing w/$1.5 CO2 Purchase Costs*
* - Porosity = 9.35%
Oil Saturation = 10.39%

FIELD DEVELOPMENT

The proposed unit includes virtually all wells which have current or historical production from the southern portion of the Eunice Monument pool, which was formerly designated the Eunice (Penrose, Grayburg, San Andres) pool. The Eunice pool was discovered March 21, 1929, upon completion of the #1 Continental Lockhart 'B-31' in Section 31, Township 21 South, Range 36 East, Lea County. This well is located approximately two miles South of the proposed unit. Records from the State of New Mexico show the following initial reservoir data for the Eunice (Penrose, Grayburg, San Andres) pool:

Initial Reservoir Pressure at 250' S.S.	1450 PSI
Reservoir Temperature at 250' S.S.	90° F
Solution Gas-Oil Ratio	432 FT^3/BBL
Saturation Pressure	1372 PSI
API Oil Gravity	32°

Following discovery, the field was developed on 40-acre spacing with the majority of wells being drilled and completed during the three year period from 1934 through 1937. Peak oil production rate for the unit wells occurred in May, 1937, when the monthly production was 791,800 barrels.

All oil wells within the unit area were classified as Eunice oil wells until 1953, when the New Mexico Oil Conservation Commission created the Eumont Gas pool overlying the Eunice and Monument oil pools. In defining the Eumont Gas pool vertical limits to include the Yates, Seven Rivers, and Queen formations, the Commission contracted the vertical limits of the Eunice and Monument oil pools to contain only the Grayburg

TABLE 1

PROPOSED ARROWHEAD GRAYBURG UNIT
PERTINENT RESERVOIR DATA

Pool Discovery Well:	Continental State J-2 No. 1
Discovery Date:	5-24-38
Producing Formation:	Grayburg
Lithology:	Dolomite
Average Porosity:	8%
Average Net Thickness:	85 ft
Swi:	25%
Initial Reservoir Pressure (250 S.S.):	1460 psi
Reservoir Temperature:	90° F
Oil Gravity (API):	34°
Cumulative Oil Recovery (12-31-88):	30.8 MMSTBO
Predicted Ultimate Primary Recovery:	36.1 MMSTBO
OOIP:	175.4 MMSTBO

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

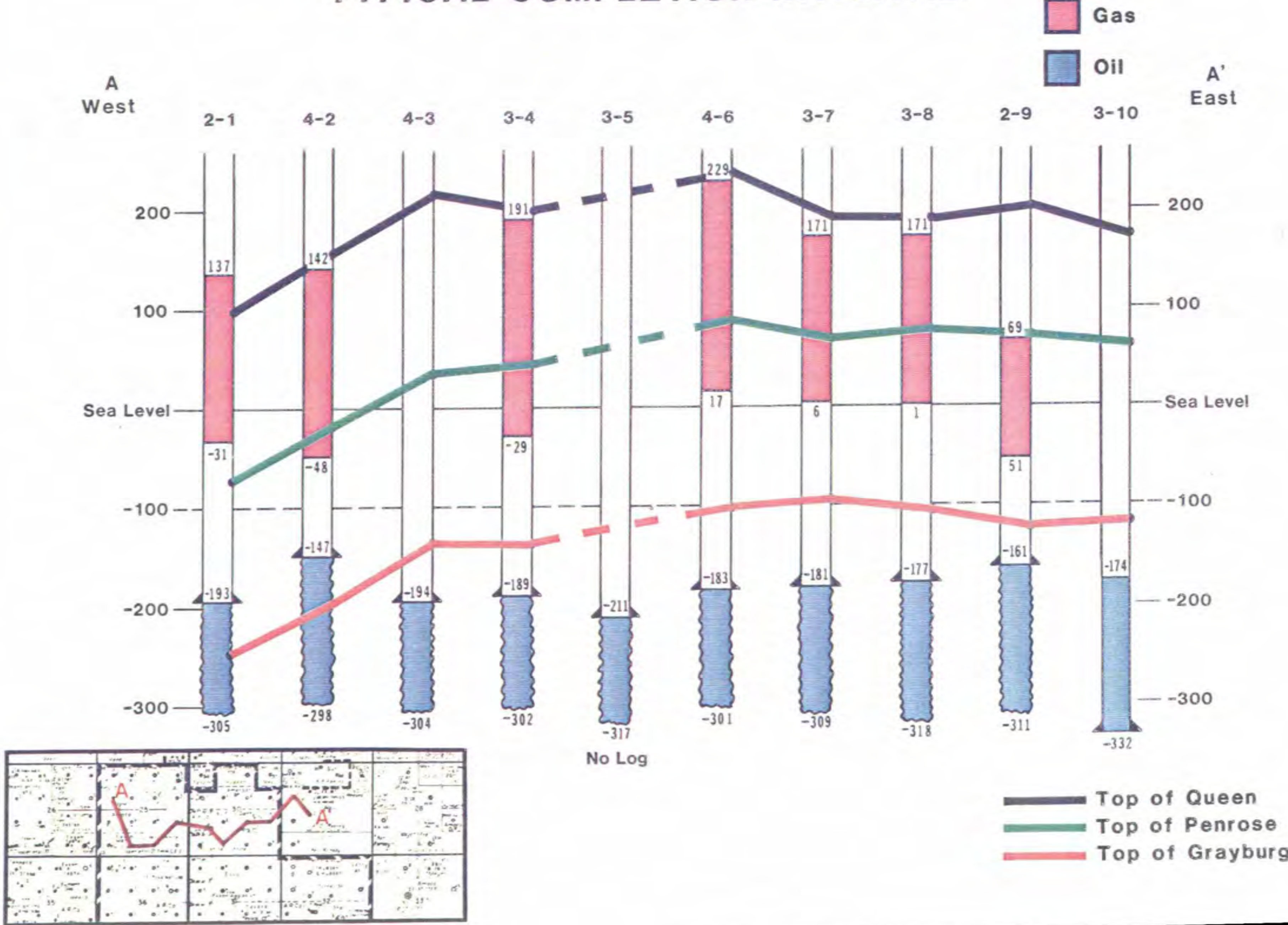


Figure 98

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

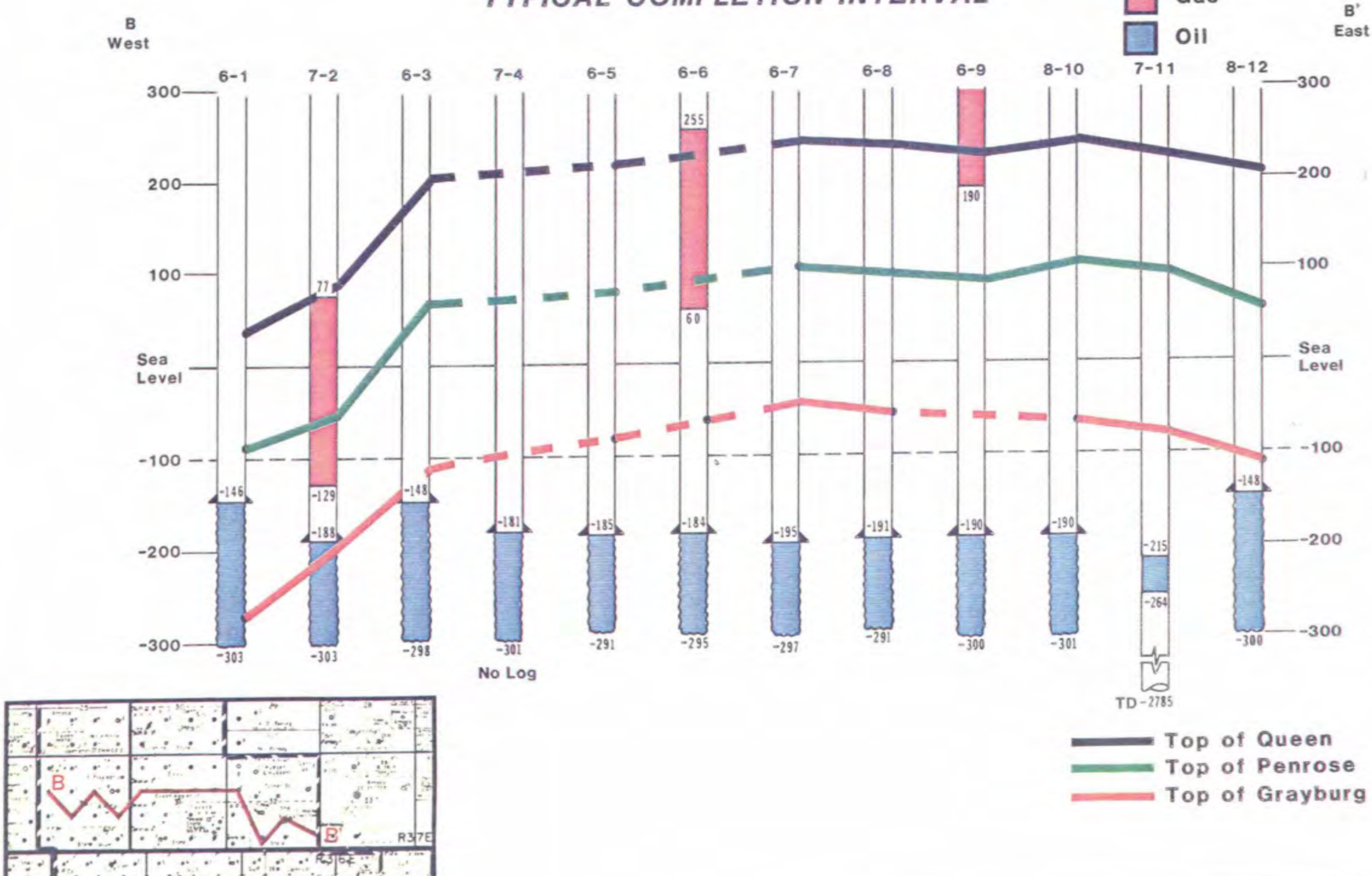
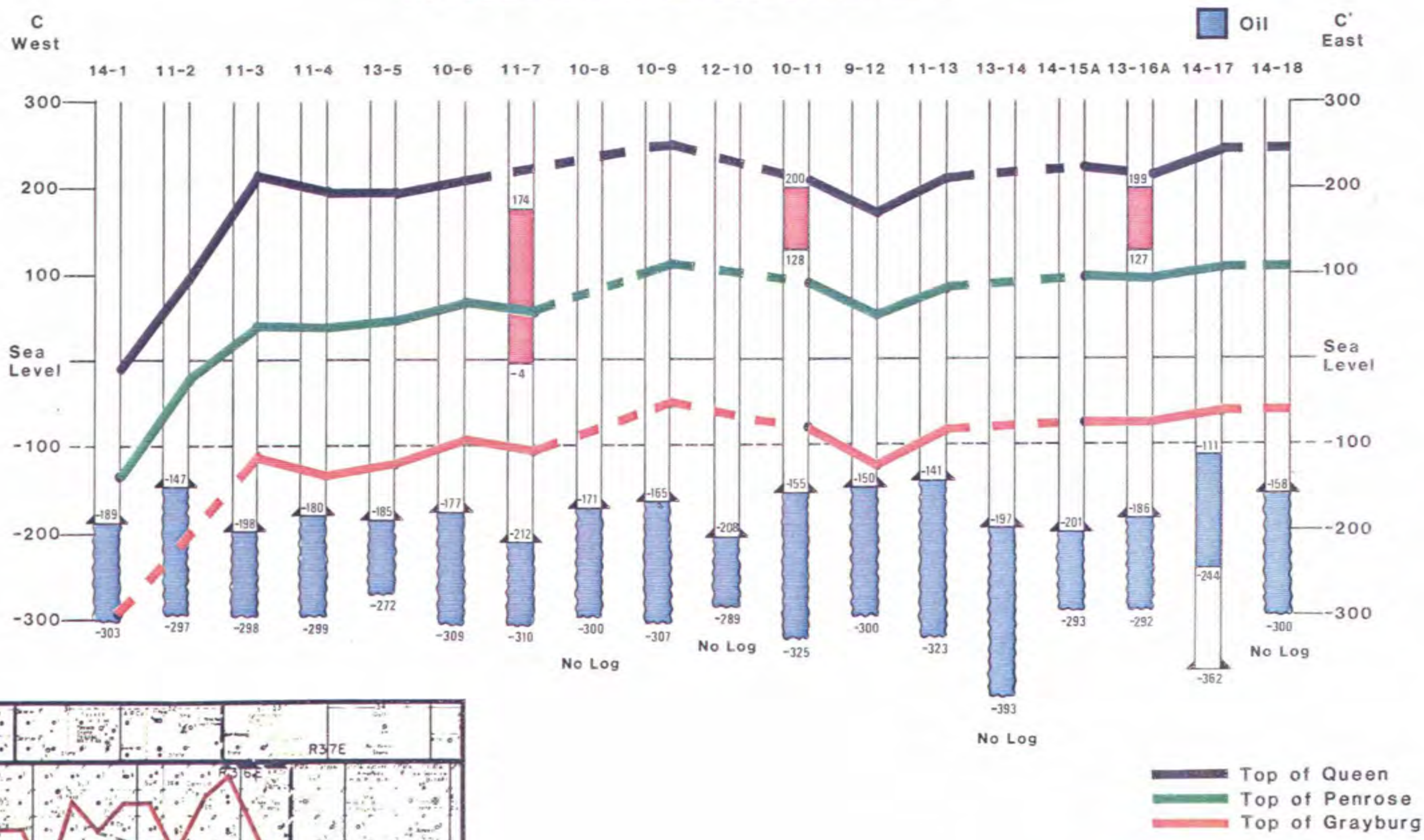


Figure 9

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL



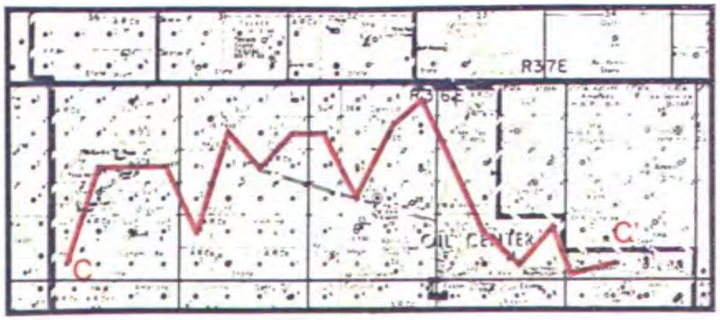


Figure 10

PROPOSED EUNICE MONUMENT SOUTH UNIT
TYPICAL COMPLETION INTERVAL

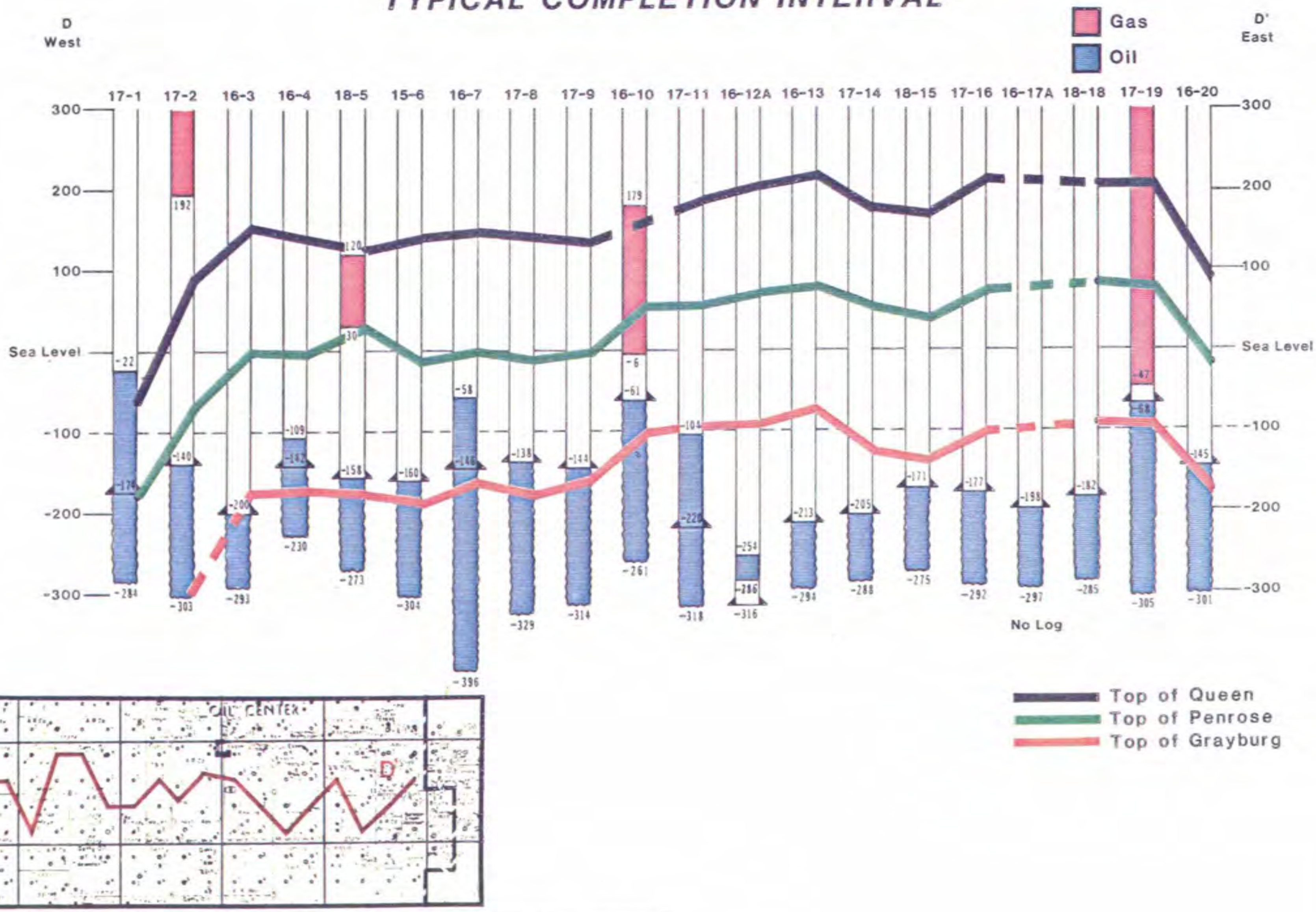
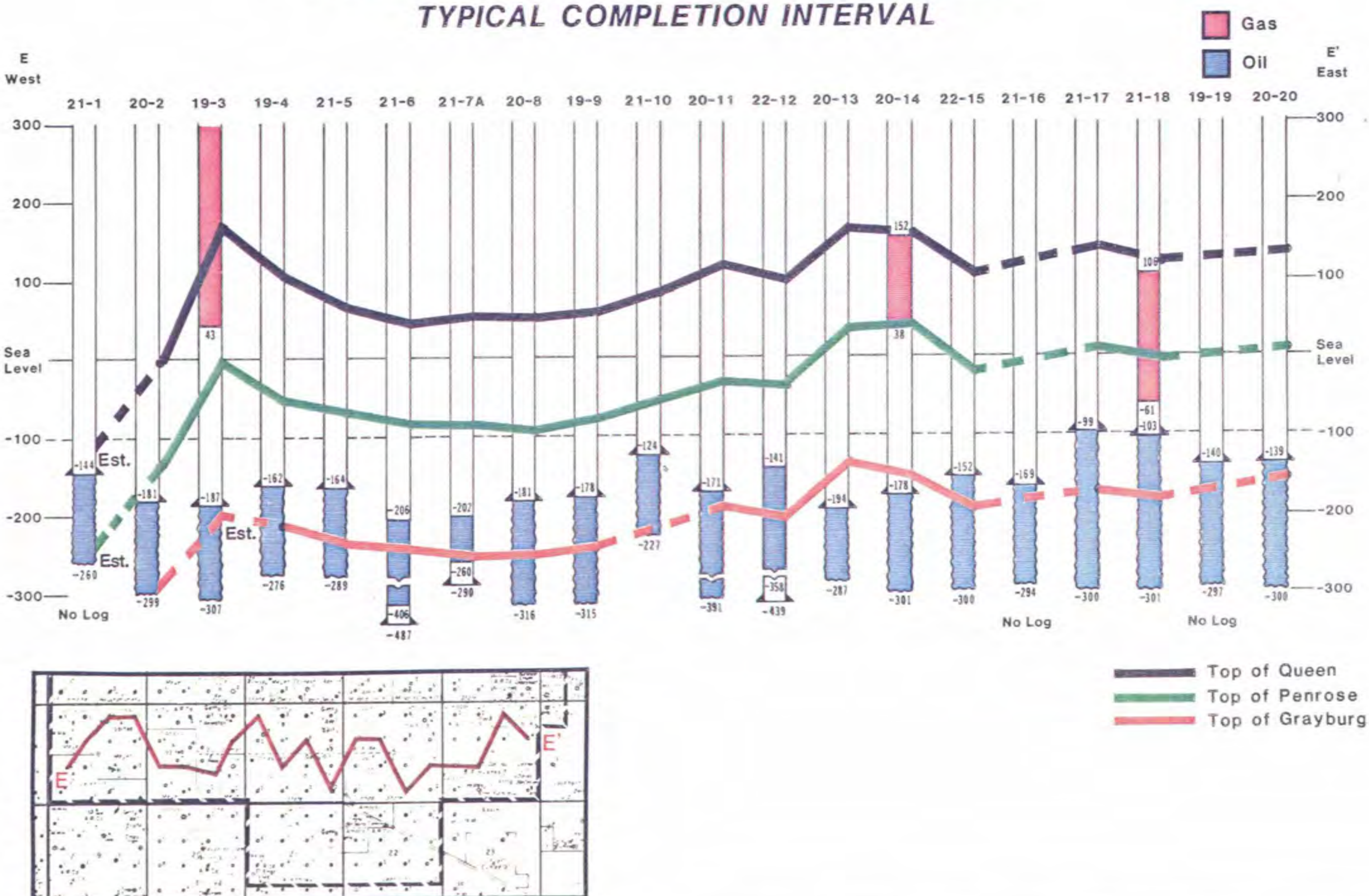


Figure 10

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL



PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

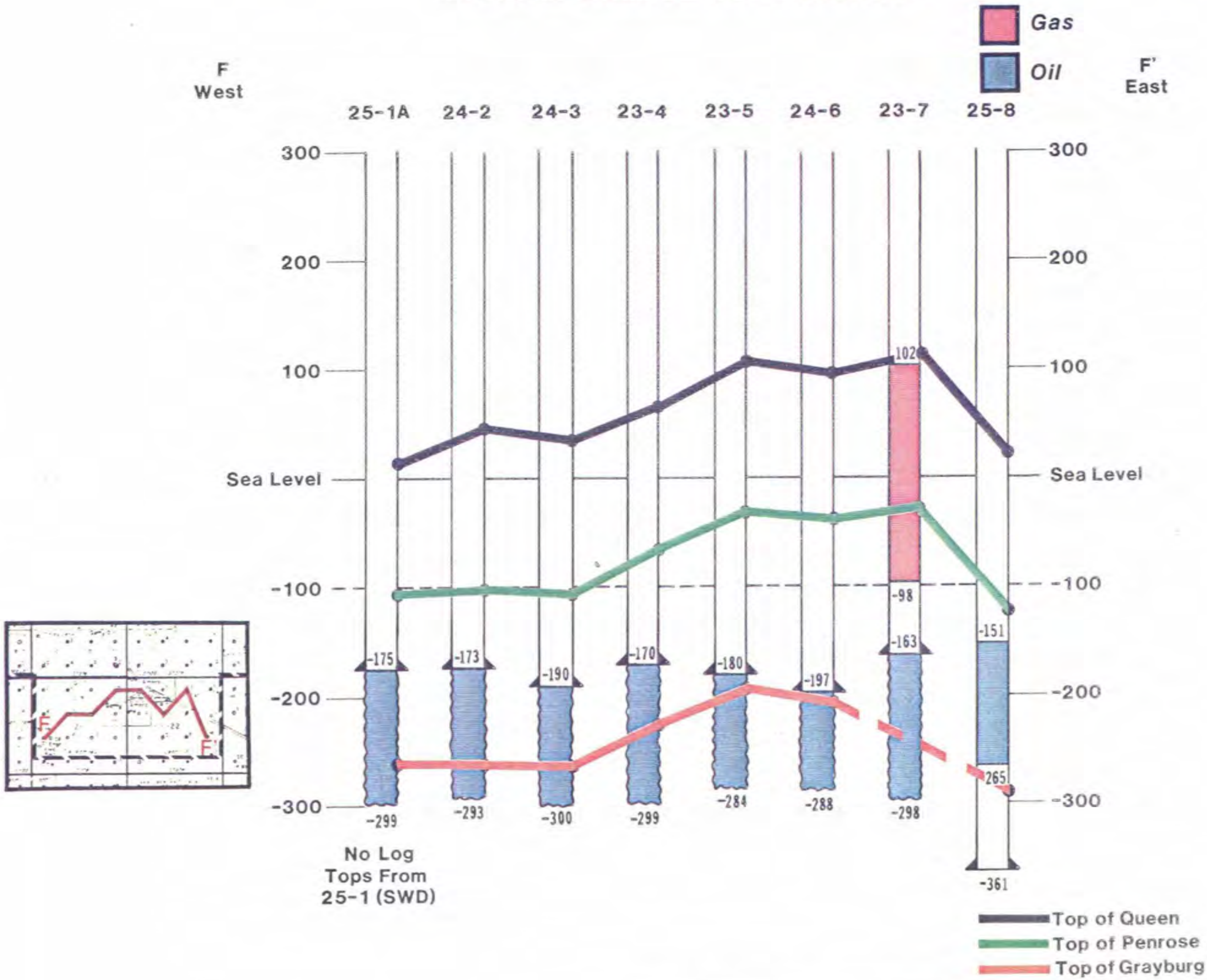


Figure 3

PROPOSED EUNICE MONUMENT SOUTH UNIT
TYPICAL COMPLETION INTERVAL

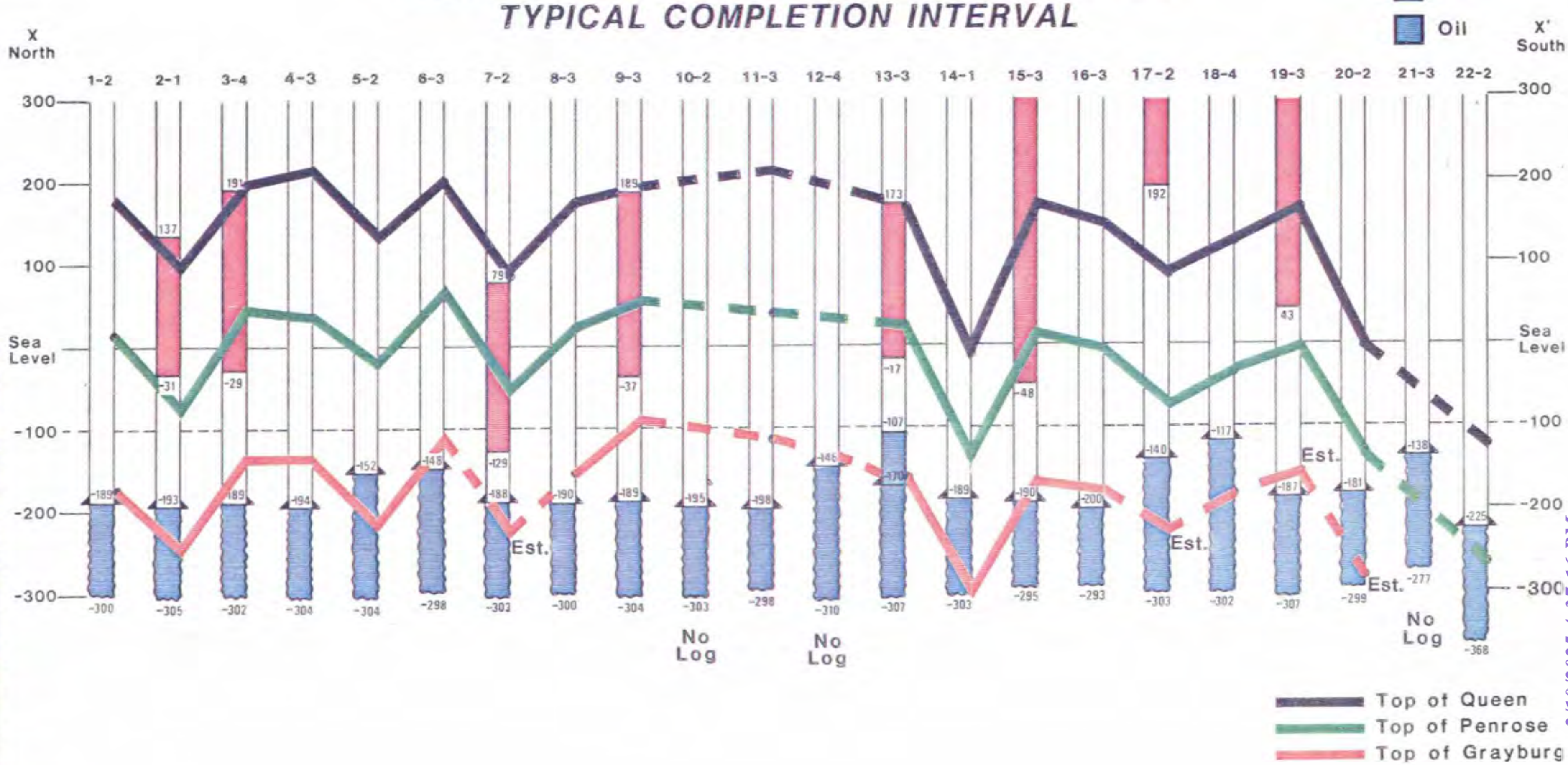


Figure 104

PROPOSED EUNICE MONUMENT SOUTH UNIT
TYPICAL COMPLETION INTERVAL

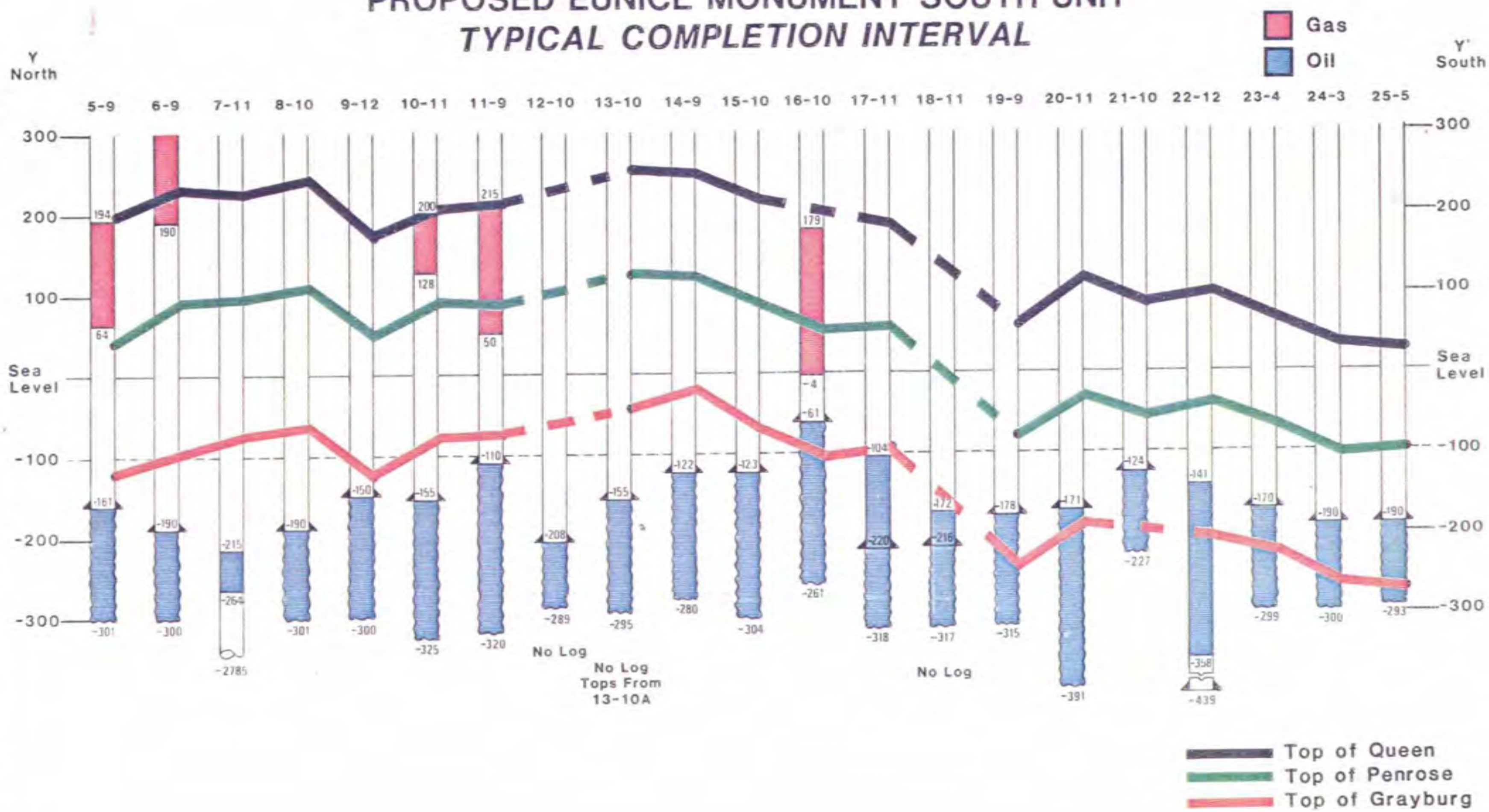


Figure 105

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

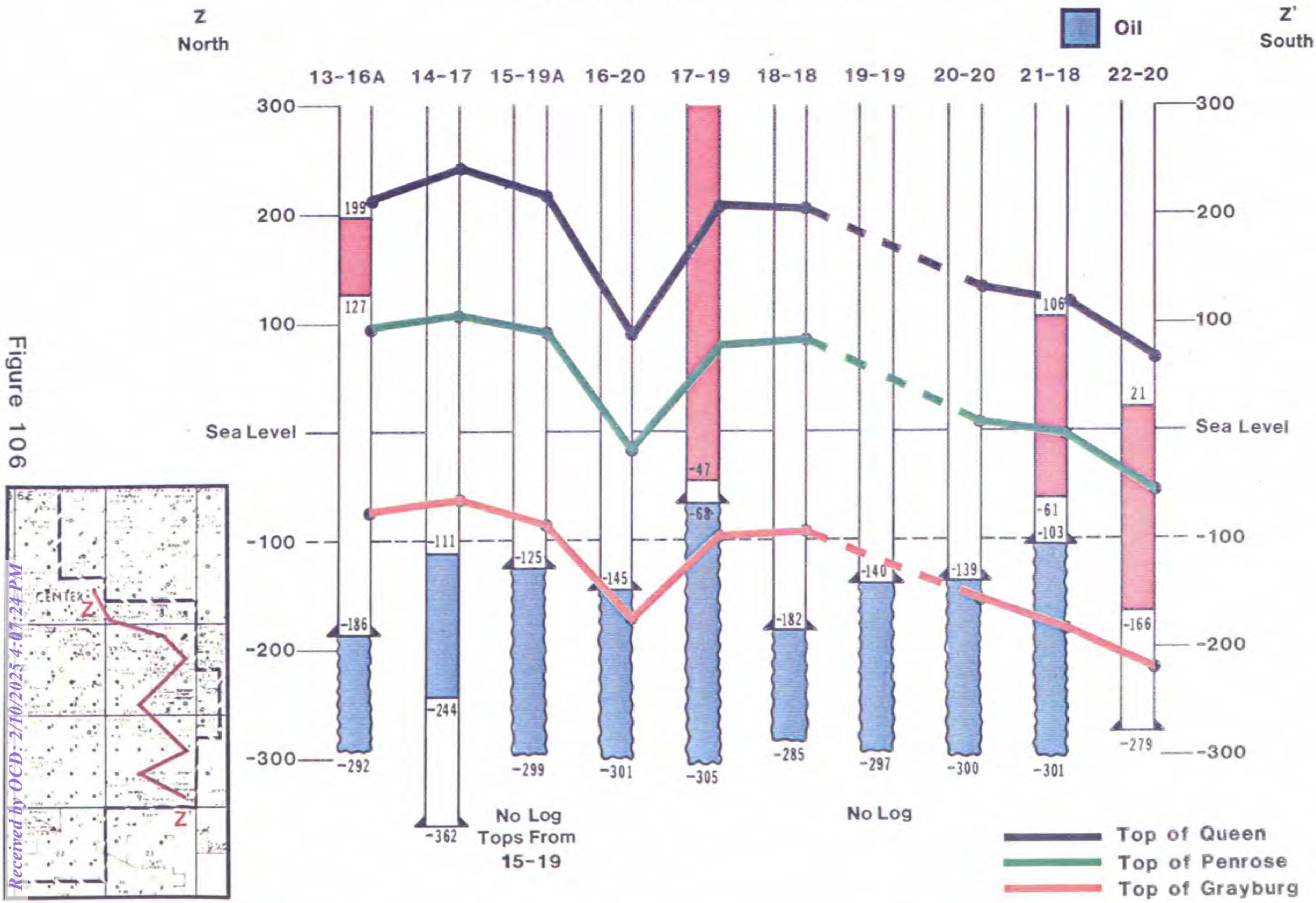


Figure 106

REBUTTAL EXHIBIT F-27

A. No. No, not at all.
Q. But based on what you know about the different fluids and how they interact within the EMSU, would you agree that any reservoir simulation list that's intended to model the EMSU should include entry of Goat Seep edge water as part of that model?
A. Oh, absolutely. Absolutely. Yes. You have to 15:52 account for all the water movement within the reservoir. bottom water coming up, edge water coming in.
Q. You mean -- it wouldn't have -- that's a big part of the EMSU story, is that edge water.
A. Yes. Yes, through time. Gee, it started way back in 1934 through 1937 is when the first edge water 15:52 started to be sucked into the reservoir.
Q. And if a reservoir simulation of the EMSU did not include Goat Seep edge water encroaching in or moving into the EMSU, it couldn't accurately represent the fluid movement or production in the EMSU. Would you agree?
A. No, probably not.
MR. RANKIN: Dr. Lindsay, I'm going to take 10 15:53 minutes, until 4:00 o'clock, just to make sure I've got everything that I want or need, that I covered all my topics.
THE DEPONENT: Okay.
MR. RANKIN: I know that Mr. Moander is going to

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

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO

CASE NOS. 23614-23617

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO.

CASE NO. 23775

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO

CASE NOS. 24018-24020, 24025

APPLICATION OF GOODNIGHT PERMIAN MIDSTREAM, LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.

DIVISION CASE NO. 22626
ORDER NO. R-22869-A
COMMISSION CASE NO. 24123

SELF-AFFIRMED REBUTTAL STATEMENT OF DR. LARRY W. LAKE, P.E.

1. My name is Dr. Larry W. Lake, P.E. I am a professor at The University of Texas at Austin where I have taught since 1978. I am engaged as a consulting petroleum engineer with Austin Consulting Petroleum Engineers Inc. for this case.

2. I previously provided direct written testimony in these cases that were filed with the Commission on August 26, 2024, on behalf of Goodnight Midstream Permian, LLC ("Goodnight"). In my direct written testimony, I reviewed the available data and information

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Rebuttal Exhibit No. G
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: February 24, 2025
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

relating to the applications filed by Goodnight Midstream and Empire in these cases. In particular, I analyzed (1) Empire's proposal to develop the San Andres as a ROZ enhanced recovery project; (2) Empire's claims that Goodnight's disposal injection into the San Andres impairs Empire's EMSU operations; and (3) provided my opinions regarding the suitability of the San Andres formation within the EMSU as a zone for produced water disposal. I have conducted a study of this information and this, along with my experience, forms the basis of my opinions expressed in that testimony.

3. I have now been asked to prepare rebuttal testimony addressing certain of the opinions and conclusions offered by Empire's witnesses Mr. William West and Dr. James Buchwalter.

4. I understand that Empire's witnesses will file rebuttal testimony concurrent with the filing of my rebuttal testimony and the rebuttal testimony of Goodnight's other witnesses. I have made a good faith effort to address Empire's testimony based on the information I have, but I reserve the right to revise or expand my rebuttal testimony or to respond to new assertions, allegations, or testimony of Empire or its witnesses. I also reserve the right to amend or supplement this statement, if necessary, should additional information become available to me, and to further rebut any related opinions reached by experts related to these cases.

Summary of Rebuttal Opinions

- Mr. West's economic analysis that he presents through a 72-pattern and 250-pattern forecast is driven by his use of dimensionless curves that estimate oil production and CO2 recovery. Dimensionless curves can be a useful engineering tool for enhanced oil recovery projects to estimate expected (1) oil recovery for a given volume of CO2 injected and (2) CO2 recovery following injection. These estimates are useful to assess the potential economics of a proposed project, which depend on oil recovery to offset costs and generate revenue and CO2, which is generally the largest operating cost. However, because dimensionless curves are deterministic, meaning they generate a set oil recovery for a given volume of CO2 injected and a set volume of CO2 recovered for a given volume of CO2 injected, it is important to only use dimensionless curves that are appropriate for the system being evaluated.

- Mr. West uses dimensionless curves from a 2009 SPE paper that addresses CO2 demand, not oil recovery, in Wyoming fields without showing the curves are appropriate for application in a San Andres residual oil zone project in the EMSU. This is unlikely to be true in this application.
- Mr. West's reliance on RFT measurements to show that the Grayburg and San Andres formations are in communication tends to support the opposite conclusion. The absence of a straight line between his RFT measurements and depth indicates poor vertical communication.
- Dr. Buchwalter's testimony is based on a numerical simulation study that is the result of a trial-and-error approach following more than 500 simulation attempts. Many expected simulation details are missing, the source of the data is not clear, and the geologic model is not provided, which is a substantial omission given the complexity of this carbonate system. The source of the porosity and permeability values are not initially provided and the values adopted do not match the literature. There is also no comparison to measured pressure.
- The lateral boundaries of the simulated Penrose and Grayburg units appear to be sealed in Dr. Buchwalter's model eliminating the possibility of water production from any source

other than the San Andres. This imposed simulation condition is exacerbated by assigning an aquifer to the western edge of the San Andres rather than the Grayburg where there is known aquifer to the west that provides a documented edge water drive within the EMSU.

- Dr. Buchwalter's model does not appear to recognize that Goodnight's San Andres disposal zone is separated from the Grayburg productive formation by at least 200 feet, which includes impermeable zones and anhydrite layers.
- The source of the relative permeability curves used is not supplied and appear to conflict with literature values. This would overestimate the irreducible water saturation for the Penrose and Grayburg, resulting in limited water movement in the Grayburg.
- The details of the simulation, many of which are guessed at, appear to be designed to emphasize water production from the San Andres formation.

Response to William West

The following is a rebuttal to the testimony of Mr. William West.

- The appropriate use of dimensionless curves has a long history in engineering and is in common use in recent oilfield practice.
- However, strictly speaking, using dimensionless curves to estimate the behavior of one system from that of another, a process known as *scaling*, is valid only if the two systems are geometrically similar. This is unlikely to be true in this application. Mr. West does not mention this.
- **Exhibit G-6** is a slide that I prepared showing the source of the dimensionless curve Mr. West relies on is SPE 122921, which was published in 2009. It shows the dimensionless

oil recovery curve presented in the paper and the same curve used in Mr. West's analysis along with the CO2 recovery curve that was taken from the same paper.

- The paper from which the procedure is taken relates to CO2 demand, not oil recovery. And it is intended for application in Wyoming reservoirs.
- It is not clear why the San Andres curve is added or where it came from. Its provenance is not present in the SPE paper, nor is the source of the data used to generate the curve documented.
- The given curve is identified to be for WAG (water-alternating-gas) injection into conventional (not ROZ) reservoirs. Its application to non-WAG injection in ROZ reservoirs is questionable or at least unsubstantiated.
- The shape of the CO2 recovery curves is substantially different from that observed in field data. **Exhibit G-7** is a slide I prepared showing Mr. West's CO2 recovery curve on the right side of the slide and recovery curves based on 50 years of experience analyzing CO2 retention efficiency for non-ROZ reservoirs on the bottom-left of the slide.
- Mr. West's curves seem to imply nearly 100% recovery of CO2 given enough time. Field data suggest that this is not true; CO2 retained in a reservoir is approximately equal to the residual oil saturation. This comment applies to non-ROZ reservoirs but it is difficult to see how ROZ performance can be much different for this parameter.
- **Exhibit G-8** is a plot of measured pressure vs. depth that was prepared by Mr. West. I am used to seeing this plot with the axis swapped. Nevertheless, the plot of pressure vs. depth is not a straight line, as would be required by theory, if there was good vertical communication in the reservoir. Without addressing whether the 1245 psi RFT

measurement is in Goodnight's San Andres disposal zone, and contrary to Mr. West's conclusion, the absence of a straight line indicates poor vertical communication with and above the indicated San Andres zone. Mr. West's reliance on this data and his analysis does not support his conclusion.

Response to Dr. James Buchwalter

The following is a rebuttal to the testimony of Dr. James Buchwalter.

- Dr. Buchwalter's testimony is mainly showing the results of a numerical simulation study that is based on trial and error with more than 500 different model attempts. The simulator appears to be a standard grid-based representation of fluid flow through a reservoir.
- Many of the details of the simulation study are missing. The source of the data is not clear. The constraints on the wells are not given. The source of the geologic model is not given, among other details.
- What appears to have been done is that the oil production rate was specified for several wells and the water rate calculated by the simulator. The cumulative production matches are good but the details of the simulation, many of which are guessed at, appear to be designed to emphasize water production from the San Andres formation. **Exhibit G-9** is a slide I prepared showing a sample of the history matches presented for Dr. Buchwalter's model results, pointing out that no measured pressure matches were provided for full field or on a well basis. As implied above, the behavior of pressure is conclusive to the issue of connection.
- Most importantly, there is no comparison to measured pressure.

- The source of the permeability and porosity is not given. It is odd to have a spatially varying permeability with a constant porosity. **Exhibit G-10** shows Dr. Buchwalter's Exhibit E-2 with my annotations. The values given for permeability are much larger than those in the literature for these types of formations.

- Based on the figure, **Exhibit G-11**, the Grayburg unit is sitting immediately on top of the San Andres. In reality, there is a couple hundred-foot gap of non-reservoir rock. The absence of a gap does not account for or reflect the sequence boundary/permeability barrier that is known to separate the Grayburg and San Andres formations.

- The lateral boundaries of the Penrose and Grayburg units in the model appear to be sealed thus eliminating the possibility of any water production from any source other than the San Andres. This is exacerbated by the assignment of an aquifer to the edge of the San Andres and the exclusion of a known aquifer to the west that is connected to and in communication with the Grayburg in the EMSU.

- The source of the relative permeability data is not given. **Exhibit G-12** is a slide I prepared showing the relative permeability curves used in Dr. Buchwalter's model for the Penrose/Grayburg and San Andres. As noted, Dr. Buchwalter's relative permeability curves overstate the irreducible water saturation for these zones, restricting water movement in the Grayburg in the model.

- There are many Grayburg curves in the literature. They usually show residual water saturations in the 15-25% range. Exhibit 7 shows the range of relative permeability curves found in the literature. The value 35% used in Dr. Buchwalter's model will suppress water movement in the Grayburg unit, again focusing the source of the produced water to be the San Andres unit.

- To repeat, the large residual water saturation, the presumed proximity to the San Andres model layer, the (evidently) lack of communication on the edges of the simulated Grayburg unit, and the absence of external water sources makes it appear the express purpose of the simulation is to direct flow from the San Andres to Grayburg unit.

Conclusions

1. I've reviewed Mr. West's testimony and Dr. Buchwalter's testimony and their related materials and data. Nothing I have seen or reviewed causes me to change my opinions or conclusions stated in my direct written testimony submitted in August 2024.

2 The Grayburg and San Andres formations show pressure differences between the producing reservoir and the disposal aquifer. Consistent and significant pressure differences like this are conclusive evidence of lack of communication.

3. Separation between the Grayburg productive formation and the San Andres disposal zone means the San Andres aquifer in the EMSU is not a ROZ according to the standard model of a residual oil zone underlying a main pay zone.

4. Because of the large injection rate and small pressure increase from Goodnight's disposal, the San Andres aquifer is likely fractured and/or heavily karsted. Such reservoir properties imply that were CO2 to be injected it is likely to have poor volumetric sweep in this interval. Mr. West's economic analysis and use of unsubstantiated dimensionless curves fails to take this known heterogeneity into account.

5. With a poor volumetric sweep and small concentration of oil, the San Andres aquifer is not reasonable target for any type of recovery.

6. I affirm under penalty of perjury under the laws of the State of New Mexico that the foregoing statements are true and correct. I understand that this self-affirmed statement will be used as written testimony in this case. This statement is made on the date next to my signature below.

Larry W. Lake

____
Dr. Larry W. Lake, P.E.

2/7/2025
Date

34181831_v1

Lake Rebuttal Materials

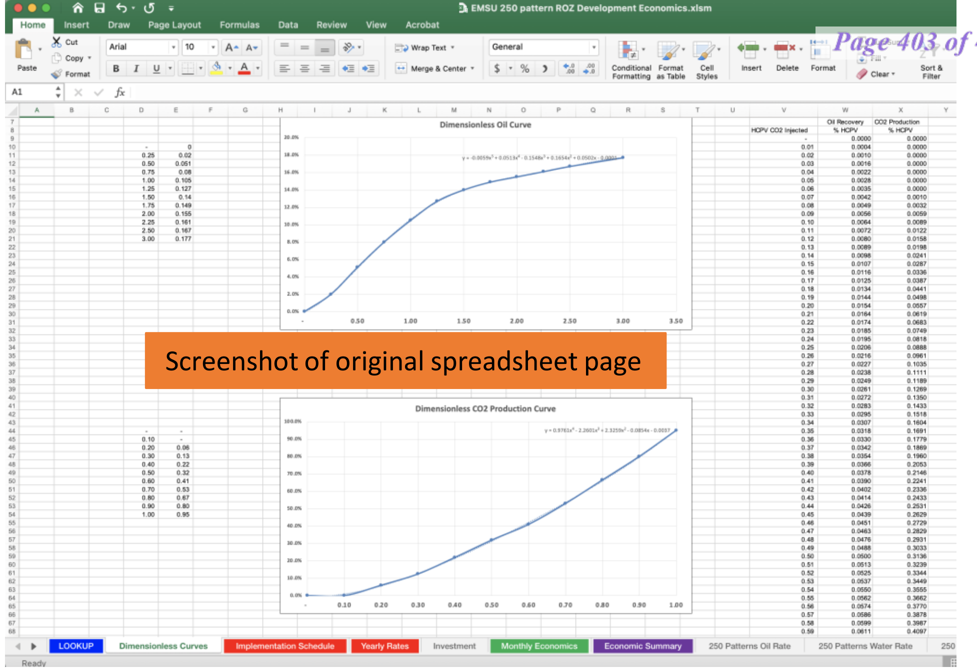
Goodnight Exhibits G-6 through G-12

Exhibit G-6.

Rebuttal of William West testimony

From EMSU 250 pattern ROZ Development Economics.xlsm and EMSU 72 pattern ROZ Development Economics.xlsm provided by West

- Dimensionless Oil Curve
  - West uses as basis for CO_2 economics
  - From paper relating to CO_2 demand in Wyoming (SPE 122921, Figure 4)
  - San Andres curve is included as a throw away and source data not documented in the paper
  - This is a WAG curve not continuous CO_2 injection (as proposed by Empire)



Screenshot of original spreadsheet page

SPE 122921

Estimates of Potential CO_2 Demand for CO_2 EOR in Wyoming Basins

S. Wo, SPE, L.D. Whitman, SPE, and J.R. Steidtmann, Enhanced Oil Recovery Institute, University of Wyoming

This paper was prepared for presentation at the 2009 SPE Rocky Mountain Petroleum Technology Conference held in Denver, Colorado, USA, 14–16 April 2009.

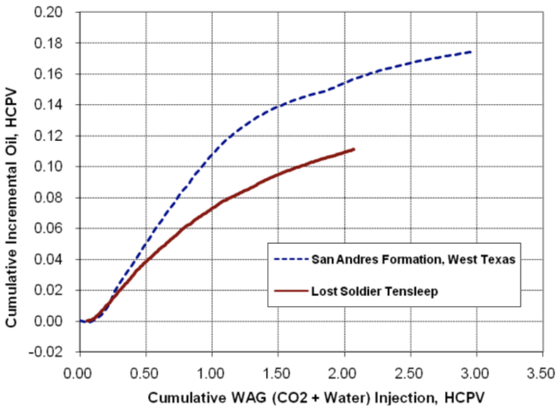
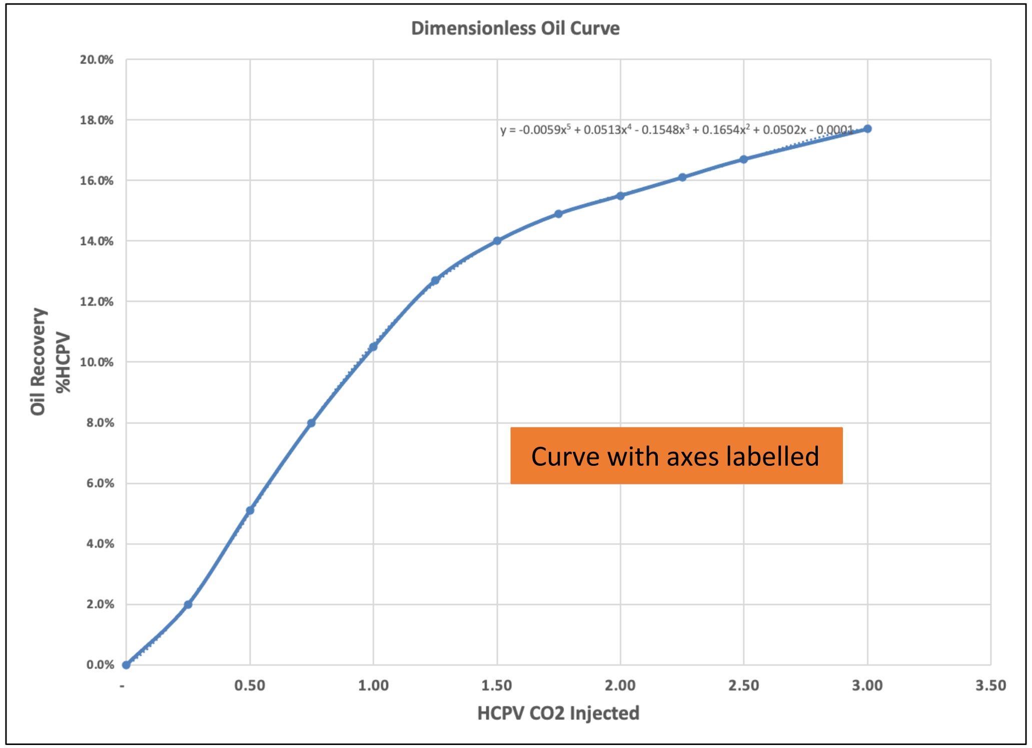


Figure 4. Dimensionless curves of incremental oil versus total WAG injection



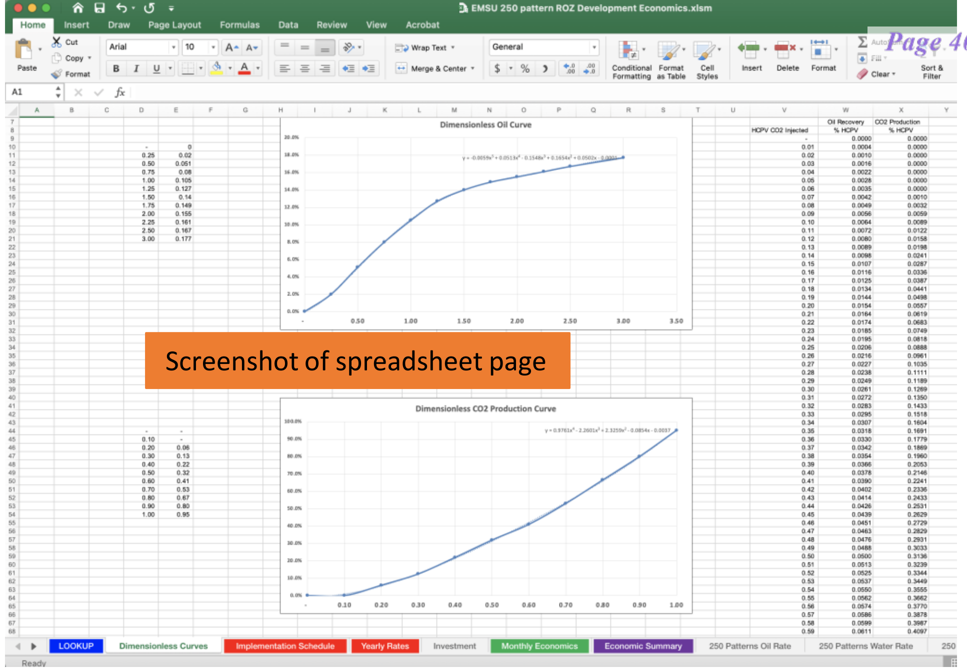
Curve with axes labelled

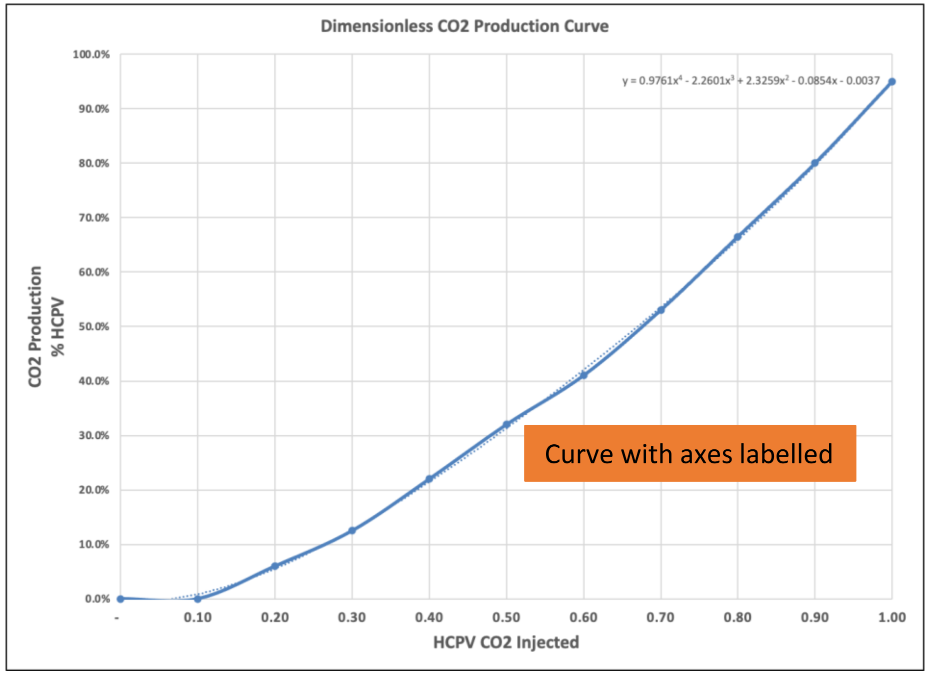
Exhibit G-7.

Rebuttal of William West testimony

From EMSU 250 pattern ROZ Development Economics.xlsm and EMSU 72 pattern ROZ Development Economics.xlsm provided by West

- Dimensionless CO2 Production Curve
  - West shows CO2 recovery >95%
  - CO2 retained is approximately equal to residual oil saturation





14th International Conference on Greenhouse Gas Control Technologies, GHGT-14

21st -25th October 2018, Melbourne, Australia

Fifty years of field observations: Lessons for CO_2 storage from CO_2 enhanced oil recovery

Larry W. Lake[a], Mohammad Lotfollahi[a], Steven L. Bryant[a,b]

[a]The University of Texas at Austin, 200 E. Dean Keeton - STOP C0304, Austin, TX 78712, USA
[b]University of Calgary, EEEL 267E, 2500 University Drive NW, Calgary, AB T2N 1N4, CANADA

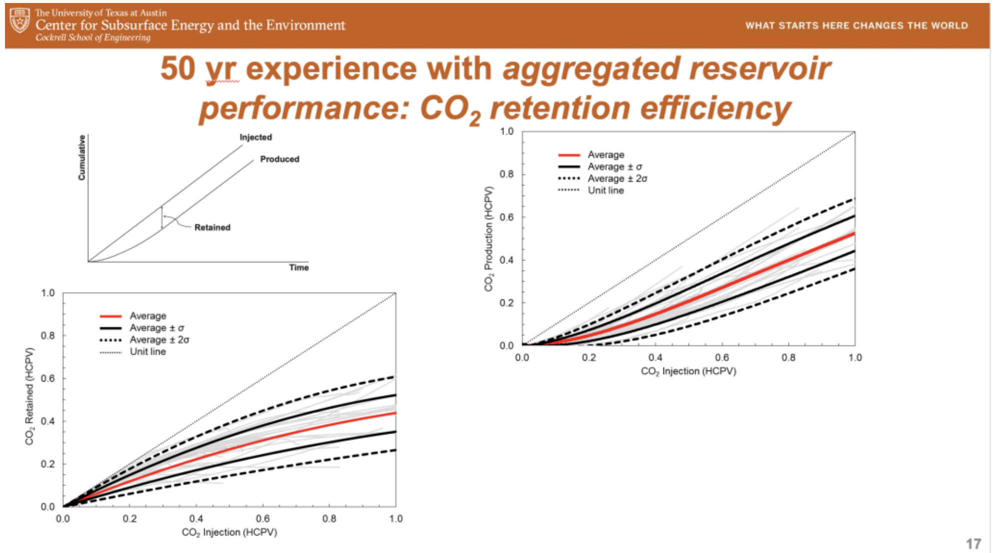


Exhibit G-8:

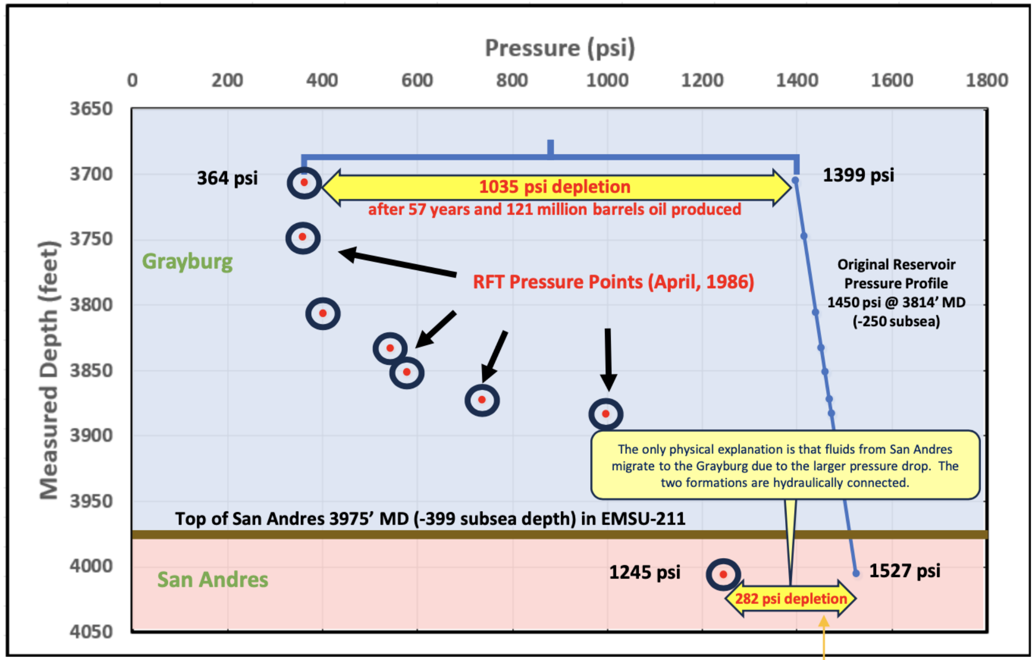
Rebuttal of William West testimony Exhibit G-4

West's pressure measurements at EMSU-211 as shown in Exhibit G-4

With communication between zones, this should be a straight line (with a water gradient at this depth).

Pressure Depletion Prior To Water Injection
(Pressure Measured in EMSU-211 April, 1986)

Exhibit G-4



Elevation for EMSU-211 is 3576' above sea level

after no fluids production from San Andres

KEY POINTS

- This is a graphical presentation of Exhibit F-3 showing pressures measured with depth in the EMSU-211 well during April, 1986.
- Seven pressure points in the Grayburg interval indicated 400 psi to 1035 psi depletion due to production of 121 million barrels oil.
- Although no production was made from the San Andres interval, pressure measurement indicated 282 psi depletion.
- This indicates that the Grayburg and San Andres are in pressure communication.

4

Exhibit G-9.

Rebuttal of Dr. James Buchwalter testimony

- No pressure matches provided for the full field or by well.

Exhibit E-3: Simulation History Match and Prediction

Water Disposal Rates Decline starting in 2027 Due To San Andres Pressuring Up (No Spillover)

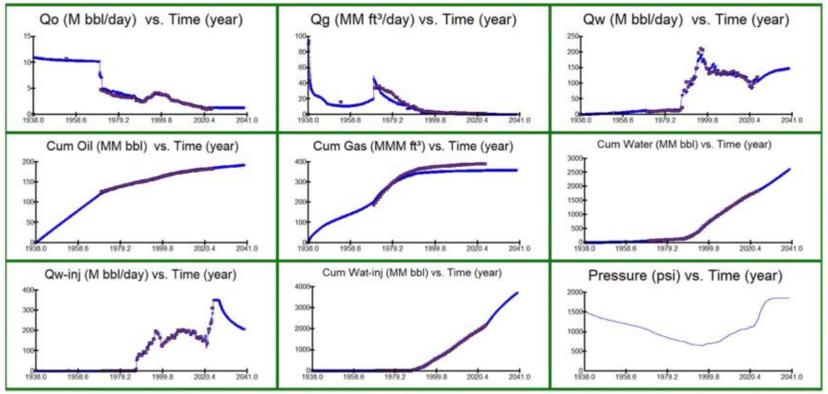


Exhibit E-7: Simulation Model Average Reservoir Pressure

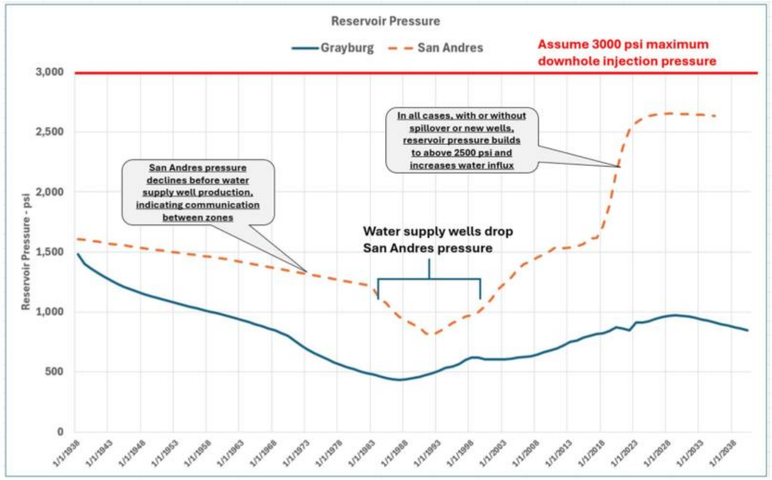


Exhibit E-10: EMSU, EMSU-B, and AGU History Match Base Case (220,000 BWPD Spillover)

The water production rate increases 1/1/2024 by 220,000 BWPD from the 11 spillover wells located in the aquifer. This allows for the increased SWD rates to be maintained longer, felt to be possible by the very large San Andres aquifer.

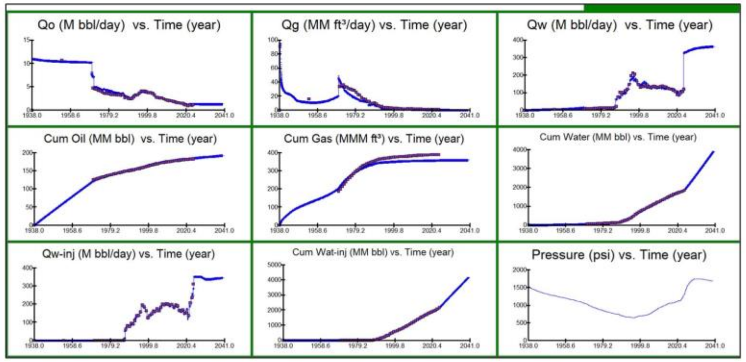


Exhibit G-10.

Annotated Buchwalter Exhibit E-2

values from Empire Base Case Model Simulation Input Grids IMPORTANT DATA.xlsx and FINAL_MODSA_1986_10I.VOL

Layer	KX	KY	KZ	Comments
1	100	100	1	Penrose
2	100	100	0.2	Penrose
3	500	500	1	Grayburg
4	500	500	1	Grayburg
5	100	100	1	Grayburg
6	100	100	1	Grayburg
7	100	100	1	Grayburg
8	250	250	variable	San Andres
9	250	250	1	San Andres
10	250	250	1	San Andres

- Layer 8 KZ
  - Range 0.05 to 12.5 mD
  - Average 0.9 mD

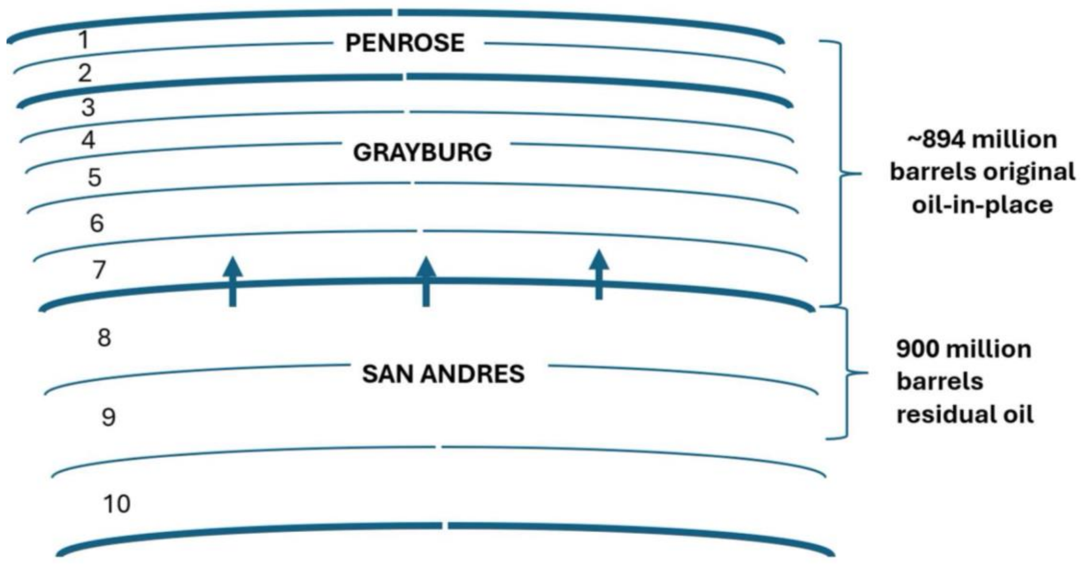
Layer	phi description	average phi	Comments
1	constant	0.06	Penrose
2	constant	0.06	Penrose
3	variable	0.08	Grayburg
4	variable	0.08	Grayburg
5	variable	0.08	Grayburg
6	variable	0.08	Grayburg
7	variable	0.08	Grayburg
8	constant	0.064	San Andres
9	constant	0.064	San Andres
10	constant	0.064	San Andres

Permeability Values

- No references provided for these values
- Not consistent with literature values (much higher)
- …

Porosity Values

- No references provided for these values
- No basis given for porosity distribution
- …



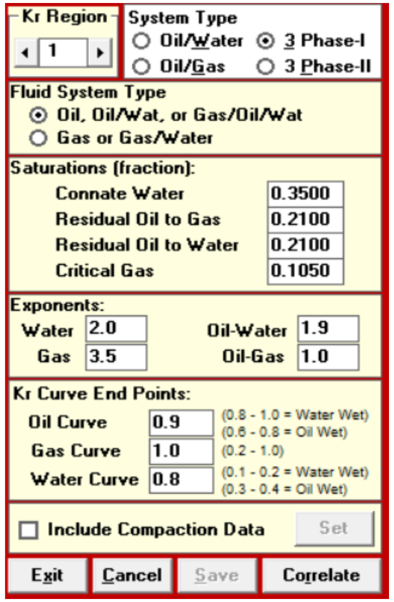
INITIAL FLUID VOLUMES BY LAYER

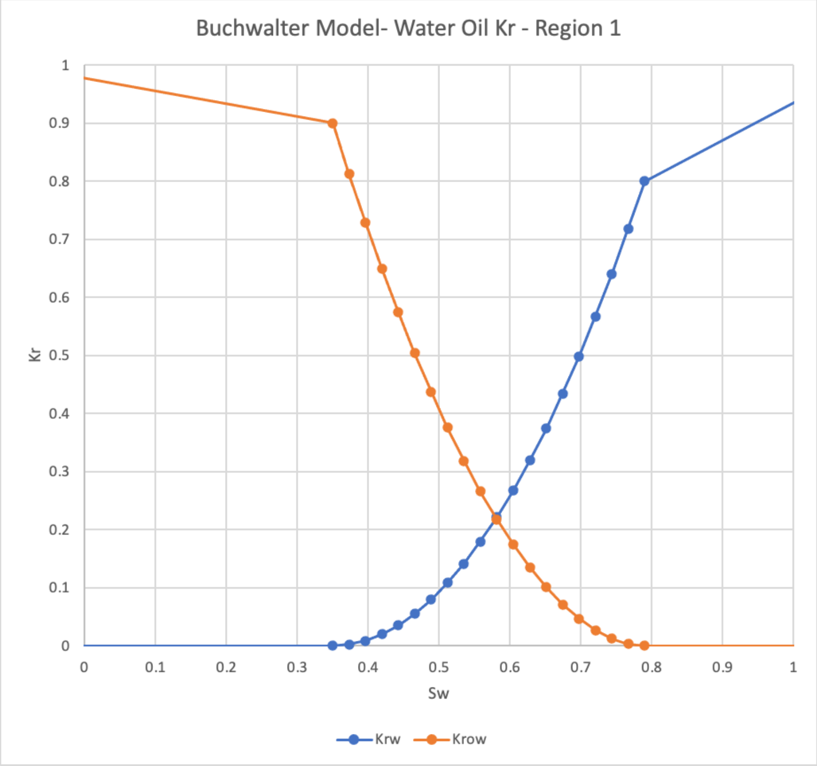
LAYER	LIQUID OIL IN PLACE (MMstb)	SOLUTION OIL IN PLACE (MMstb)	TOTAL OIL IN PLACE (MMstb)	VAPOR GAS IN PLACE (Bscf)	SOLUTION GAS IN PLACE (Bscf)	TOTAL GAS IN PLACE (Bscf)	TOTAL WATER IN PLACE (MMstb)
1	29.851	0.000	29.851	74.483	9.613	84.096	80.
2	69.024	0.000	69.024	45.072	22.312	67.384	81.
3	343.096	0.000	343.096	47.851	111.122	158.973	307.
4	155.403	0.000	155.403	4.647	50.459	55.106	207.
5	129.639	0.000	129.639	2.258	42.115	44.373	240.
6	104.799	0.000	104.799	0.404	34.047	34.451	271.
7	62.081	0.000	62.081	0.000	20.174	20.174	320.
8	898.153	0.000	898.153	0.000	13.760	13.760	51951.
9	0.173	0.000	0.173	0.000	0.003	0.003	52883.
10	0.000	0.000	0.000	0.000	0.000	0.000	52897.
TOTAL	1792.218	0.000	1792.218	174.715	303.604	478.320	159234.

Rebuttal of Dr. James Buchwalter testimony

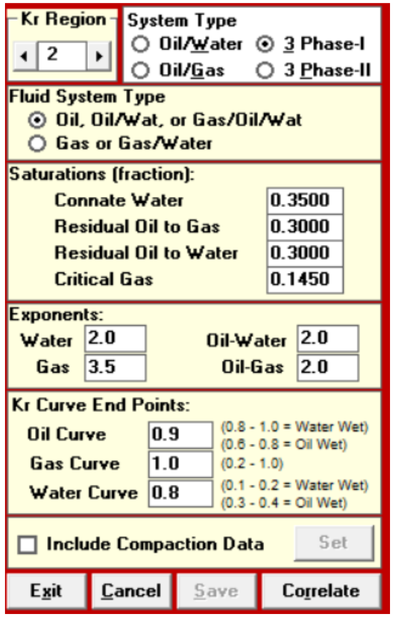
- Relative Permeability – data from Empire Base Case Model Simulation Input Grids IMPORTANT DATA.xlsx and FINAL_MODSA_1986_10I.BUP
  - Model Irreducible water saturation = 35% (Penrose, Grayburg, San Andres)
  - Too conservative, water movement limited
  - Not representative of literature values (15-25%) or observed core data

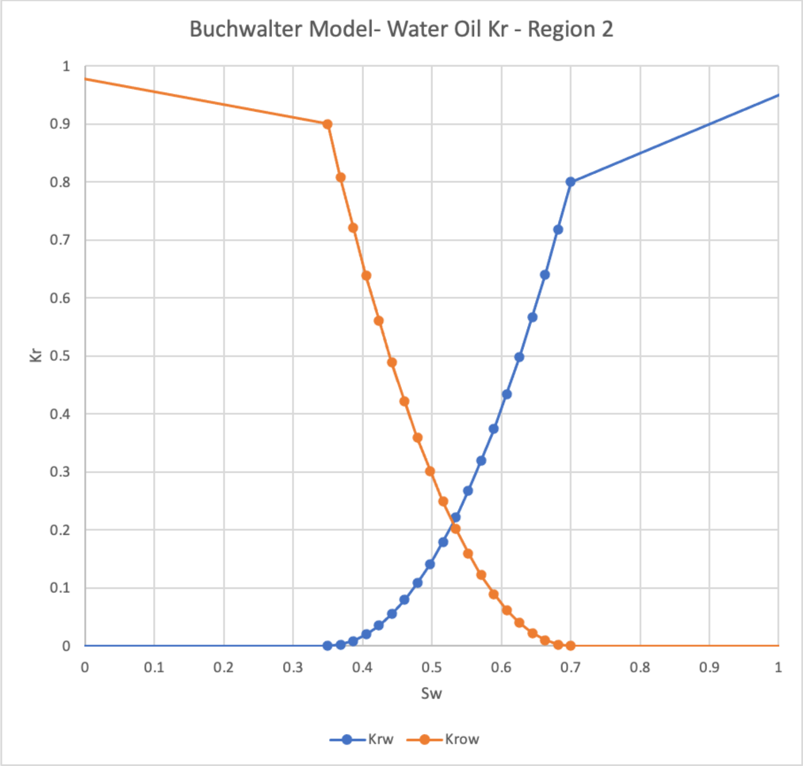
Penrose/Grayburg





San Andres





Must initialize the San Andres region with 70% total water saturation above oil-water contact
35% of the water saturation is immobile (connate) and the other 35% of the pore space water is moveable
The 30% residual oil saturation will not move unless EOR processes are applied.

Exhibit G-12.

Rebuttal of Dr. James Buchwalter testimony

- Relative Permeability
  - Model Irreducible water saturation = 35% (Penrose, Grayburg, San Andres)
  - Too conservative, water movement limited
  - Not representative of literature values (15-25%) or observed core data

Hobbs Field, Lea County, NM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

January 12, 2017

Mr. Frederick Forthuber
Occidental Oil and Gas Corporation
5 Greenway Plaza, Suite 110
Houston, Texas 77046-0521

Re: Monitoring, Reporting and Verification (MRV) Plan for Hobbs Field

Dear Mr. Forthuber:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for the Hobbs Field as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Occidental Permian Ltd. for the Hobbs Field as the final MRV plan. The MRV Plan Approval Number is 1009647-1. This decision is effective January 17, 2017 and appealable to EPA's Environmental Appeals Board under 40 CFR Part 78.

If you have any questions regarding this determination, please write to ghgreporting@epa.gov and a member of the Greenhouse Gas Reporting Program will respond.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

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Top of Basal Grayburg down to -735 Total Vertical Depth (structural spill point)	
Variables	
Boundary	**Spill Point Contour**
Pore Volume [RB]	**4,769,117,630**
B_{CO2} [BBL/MCF]	**0.45**
S_{wirr}	**0.15**
Sor_{CO2}	**0.10**
Max CO_2 [MCF]	**7,948,529,383**
Max CO_2 [TCF]	**7.95**

$$CO_2(max) = Volume\ (RB) * (1 - S_{wirr} - S_{orCO_2}) / B_{CO_2}$$

Where:

$CO_2(max)$ = the maximum amount of storage capacity
Volume (RB) = the volume in Reservoir Barrels of the rock formation
B_{CO2} = the formation volume factor for CO_2
S_{wirr} = the irreducible water saturation

SPE
Society of Petroleum Engineers

SPE 16721

East Vacuum Grayburg-San Andres Unit CO_2 Injection Project: Development and Results to Date
by M.H. Brownlee and L.A. Sugg, Phillips Petroleum Co.
SPE Members

TABLE I

East Vacuum Grayburg-San Andres Unit Reservoir and Fluid Characteristics and Recoveries [1,3]

Depth, Feet	4400
Type Formation	Dolomite
Reservoir Temperature, °F	101
Original Reservoir Pressure, PSIG	1613
Average Net Pay, Feet	71
Average Porosity, %	11.7
Average Permeability, MD.	1 1.0
Area, Acres	7025
Connate Water Saturation, %	15.9
Original Oil Formation Volume Factor	1.288
Initial Solution Gas/Oil Ratio, SCF/STB	465
Oil Gravity, °API	38
Original Gas Cap	No
Original Oil In Place (OOIP), MMBO	297

Forecasted Recoveries

Primary	78.0 MMBO	25% OOIP
Secondary	40.8	15%
Tertiary	20.7	8%*
TOTAL	139.5 MMBO	47% OOIP

*Of CO_2 Project Area Only

Technical Committee Report
Proposed Arrowhead Grayburg Unit
Lea County, New Mexico

Chevron

TABLE 1

PROPOSED ARROWHEAD GRAYBURG UNIT
PERTINENT RESERVOIR DATA

September 1989

Pool Discovery Well:	Continental State J-2 No. 1
Discovery Date:	5-24-38
Producing Formation:	Grayburg
Lithology:	Dolomite
Average Porosity:	8%
Average Net Thickness:	85 ft
Swi:	25%
Initial Reservoir Pressure (250 S.S.):	1460 psi
Reservoir Temperature:	90° F
Oil Gravity (API):	34°
Cumulative Oil Recovery (12-31-88):	30.8 MMSTBO
Predicted Ultimate Primary Recovery:	36.1 MMSTBO
OOIP:	175.4 MMSTBO

Sufficient modern log data are not available to calculate an accurate volumetric OOIP for the Arrowhead Grayburg Pool. However, log to core transforms and reservoir characterizations developed for the EMSU can be applied to the proposed Unit because of the similarities between the two fields. Estimates of reservoir parameters utilizing the EMSU similarities are: porosity = 8%, Hnet = 85 ft, Swi = 25%, and Boi = 1.2 RB/STB. The OOIP calculated for the 5,320 acres that have produced from the proposed Unit, using the estimated reservoir parameters, is 175.4 MMSTBO. A summary of pertinent reservoir data is shown in Table 1.