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 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
Exhibit No. C
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

2. My experience includes designing and geologic oversight of saltwater disposal well (SWD) permitting, drilling, and completions, SWD well workovers, enhanced oil recovery operations (EOR), designing plugging operations, and conducting investigations of alleged saltwater disposal well impacts to other oil and gas producing wells, as well as to surface and groundwater contamination. I have also served as a testifying and/or consulting expert on a broad variety of issues that range from surface and subsurface geology, groundwater and surface water contamination issues, plugging operations, Class II and Class III injection wells, and petroleum engineering incidents in New Mexico, Ohio, Oklahoma, Texas, and West Virginia. I was the principal geologist for ALL Consulting, LLC on all of Goodnight Midstream Permian, LLC ("Goodnight Midstream") SWD applications in New Mexico. I have been retained by Goodnight Midstream to testify as an expert in petroleum geology and petroleum engineering, Class II SWD and EOR operations, geochemical injection fluids and treatment, and corrosion issues related to Class II operations in these consolidated cases.

3. I am a Certified Petroleum Geologist #6354 by the American Association of Petroleum Geologists. I have over 42 years of experience in the energy, regulatory, and environmental industries, including work as a geological consultant for six years in the Ohio oil and gas industry drilling and completing conventional oil and gas wells and converting wells to Class II SWDs. Additionally, for over 25 years, I served as the lead geologist/Underground Injection Control (UIC) Manager at the Ohio Department of Natural Resources, Division of Oil and Gas, Division of Mineral Resources Management, and Division of Oil and Gas Resources Management in the UIC Section before my retirement from the State of Ohio in 2014. For the last 10 years, I have worked with ALL Consulting, LLC, which is a specialized professional engineering and technical services firm based out of Tulsa, Oklahoma. My experience includes

various aspects of all classes of injection well planning, design, permitting, drilling and completion operations, well production and maintenance, well remedial activities, well testing and evaluation, well and industry history, plugging and abandonment operations, groundwater investigations, fractured rock investigations, site environmental remediation and/or restoration, regulatory research and interaction, and risk analysis, management, and planning. Additionally, I am familiar from a regulatory perspective with current and historical laws, rules, and regulations applicable to the operation, abandonment, and plugging of oil and gas and Class II injection wells in Louisiana, New Mexico, Ohio, Oklahoma, Texas, and West Virginia.

4. I am an active member in several professional organizations, including the National Ground Water Association, American Association of Petroleum Geologists, and the Ohio Geological Survey. I have presented or published multiple papers 71 times on the subject of oil and gas, salt-solution mining and gas storage, orphan wells, secondary oil recovery, Class I, Class II, Class III, and Class VI injection wells, and ground water investigations related both to oil and gas and mining operations.

5. 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 attached my current curriculum vitae as **Goodnight Exhibit C-1**. It outlines my education, training, and experience, as well as a list of my publications and presentations.

6. I have also been involved in and served on national technical and regulatory workgroups in the development of carbon geosequestration [now called carbon capture utilization, and storage (CCUS)] and Class VI regulations since the mid-2000s and I currently serve on the Ground Water Protection Council National Class VI Workgroup.

7. Additionally, I have prepared a draft white paper entitled "Understanding the Relationship Between Well Integrity and CO_2" for the Ground Water Protection Council in 2023. I used the Salt Creek oilfield in Wyoming as a case study for this paper and conducted extensive research on the Salt Creek oilfield and Anadarko Petroleum Corporation's conversion of this field from waterflooding to CO_2 enhanced oil recovery. Some of the key points of this case study are as follows:

- Every well was evaluated;
- Operator reworked every wellbore including wells previously plugged and abandoned (more than 1,200 wells);
- Zonal isolation was required on all wells;
- Pressure integrity within the production casing for every production well was confirmed;
- Bottomhole pressure surveys and step rate testing were conducted for every injection well;
- Radioactive tracer surveys, temperature, and noise logs performed; and
- 4-D seismic work, including repeat 3-D seismic surveys at 10-to-12-week intervals, was conducted.

8. Setting aside whether there are recoverable hydrocarbons, this study clearly demonstrates that conversion of an existing Class II waterflooding operation to CO_2 tertiary oil recovery is a serious technical and financial challenge for any operator pursuing CO_2 tertiary oil recovery operations.

9. I believe these credentials qualify me to testify as an expert in not only petroleum geology and petroleum engineering, but also in Class I and Class II injection well operations,

which includes injection well design and construction, drilling and completion, injection fluid geochemistry, treatment, and corrosion issues associated with injection of flowback and produced water as well as make-up water for enhanced oil recovery operations.

10. This statement summarizes my analysis and opinions to date. I reserve the right to amend or supplement this statement, if necessary, should additional information become available to me, and to rebut any related opinions reached by experts related to these cases.

Summary

11. I have been asked to review the available data and information relating to the applications filed by Goodnight Midstream and Empire in these cases. I have conducted a study of available information and this, along with my experience, forms the basis of my opinions expressed herein. I have made a good faith effort to anticipate Empire's testimony based on the information I have, but I reserve the right to revise or expand my testimony or to respond to new assertions, allegations or testimony of Empire or its witnesses.

12. Specifically, I have been asked to evaluate and provide testimony on (1) an overview of the history of production in the Eunice and Monument oil fields; (2) an overview of the development of the Eunice Monument South Unit and waterflood operations; (3) geochemical and water chemistry issues in the EMSU and well corrosion issues; (4) chemical treating of Goodnight's injection wells and related protocol; (5) assessment of Empire's claims that there is communication between the Grayburg and San Andres formations; and (5) assessment and evaluation of EMSU operations and wells.

13. I have thoroughly researched all the available documents, records, and publications associated with the history and modern development of the EMSU and its operations, examination of known historic corrosion and scaling problems, geochemical analysis of the fluids, the injection operations, water supply wells, and the well construction. Additionally, I researched all types of

corrosion issues associated with the oil and gas industry, performed geologic and treatment processes assessment of Goodnight's existing San Andres saltwater disposal wells (SWDs), performed an evaluation and assessment of the EMSU operations, discussed the geologic problems associated with fractured carbonate reservoirs, and conducted an analysis of Empire's proposed CO_2 plan for tertiary oil recovery from the Grayburg Zones 3, 4, and 5 and the entire alleged residual oil zone (ROZ) in the San Andres Formation.

14. The following is a summary of my opinions and conclusions that are addressed in my statement below:

- As of 1991, Grayburg oil production wells in the EMSU had already been experiencing major corrosion issues even before commencement of water flooding operations using San Andres make-up water and decades before Goodnight initiated its San Andres disposal operations. The Grayburg Formation was known to contain H_2S and highly corrosive waters and sulfur in the crude oil before the waterflood was initiated.
- EMSU also has historically experienced barium sulfate scale deposits in many producing oil wells prior to field unitization and waterflooding. According to Chevron, "Years of production have severely depleted the EMSU reservoir and corroded the wellbores," prior to commencing the waterflood.
- Gulf Oil and Chevron elected to use the San Andres as the EMSU water supply source despite knowing that San Andres water was not compatible with the Penrose or Grayburg formation waters because it was the only source with sufficient volumes for the waterflood.

- The existing corrosion problems in the Grayburg were exacerbated with the waterflood due to the known incompatibility of the supply water from the San Andres and water within the producing Grayburg Formation.
- Corrosion issues and scale deposits typically associated with injection operations and waterflooding operations, like the EMSU, are primarily associated with CO2, H_2S, oxygen, and microbial-induced bacteria. Chlorides have little impact on corrosion in the oil and gas industry and on the EMSU project in particular.
- In addition to longstanding known corrosion issues, many of the EMSU's wells are more than 80 years old, establishing that many of the EMSU's existing wells and their well integrity along with related infrastructure may not be suitable for CO2 injection due to their age, cementing, and well construction practices.
- Empire's apparently started a systematic chemical treatment protocol apparently started only as recently as February 2022, despite the fact the EMSU has a long history of known corrosion and scaling issues. There appears to have been a gap of at least a couple years in a systematic corrosion prevention and treatment program at the EMSU or longer because we have no records from the previous operator(s) to determine what chemical treatment was utilized and whether it was part of a systematic program.[1]

[1] I note that after confirming in a discovery response to a request for documents on treatment of EMSU wells for corrosion and scaling from prior operators and changes in treatment from prior operators, Empire confirmed on August 1, 2024 that "it has conducted a diligent and thorough search of the records within its possession, custody, or control and discovered no responsive documents." On August 21, 2024, Empire provided a supplemental response that included a spreadsheet Bates OCD 23614-17 03648 containing individual descriptions of chemical treatments for various wells in the EMSU going back in time from 2023 to 1939. However, I have not had time to review this supplemental information to incorporate it into my analysis and assessment and reserve the right to amend or supplement this statement after I have had a reasonable opportunity to review the new information.

- There is a low-porosity and low-permeability barrier at the top of the San Andres along with the significant depth separation between the top of the Goodnight SWD injection intervals and the bottom of the producing zones in the Grayburg.
- There is no evidence of vertical fractures extending from the Grayburg into the San Andres and no evidence of fluids migrating between the formations.
- Empire's proposed CO2 EOR for the EMSU is seriously lacking in detailed technical considerations and would be substantially underfunded. Empire's plan does not appear credible, especially with respect to Goodnight's San Andres disposal zone because only a few of the EMSU wells are deep enough to even penetrate the San Andres.

History of the development of the Eunice and Monument oilfields[2]

15. The initial discovery of the Eunice oilfield occurred on March 8, 1929, with the discovery well being located in Section 31, T21S, R36E, Lea County, New Mexico. The wells were drilled on a 40-acre spacing and the oil-producing zone is the Grayburg Formation.

16. By September 1941, there were 490 producing oil wells and most of these wells were acidized and not shot with nitroglycerin. All wells were produced from the Grayburg Formation.

17. The original oil-water contact was at -360 feet below sea level, but as development and withdrawal of oil had taken place, water was replacing the displaced fluids and slowly raised the oil-water contact. The Gulf Oil unitization document for the Eunice Monument South Unit

[2] Sources: Bureau of Mines RI 3456 (1939); New Mexico School of Mines and Mineral Resources, Bulletin No. 18 (1942); and Gulf Oil Eunice Monument South Unitization Document (1985).

(EMSU) states that the oil-water contact had risen to -325 feet below sea level and the gas-oil contact was at -100 feet below sea level.

18. **By late 1941, over 200 oil wells were producing from 2% to 98% water with encroachment of water being uniform on the west and south parts of the field**. The effectiveness of the field's water drive is demonstrated by the small decrease in bottom-hole pressures by 1941. The field is both a solution gas and partial water drive reservoir.

19. **By 1941, only a few wells tested the upper section of the San Andres Formation with some documentation around this time indicating that future drilling intended to explore this formation more completely. There is no indication of any oil production from the San Andres.** The sulfur content of the Grayburg oil ranged from 1.1 to 1.65%.

20. The Monument part of the oilfield was discovered in early 1935. These wells were also drilled on 40-acre spacing. Historical operations in the Monument section of the oilfield to the north had a total of 473 oil wells drilled into the Grayburg Formation by July 1, 1938.

21. As with the Eunice field, the productive oil zone in the Monument field is also the Grayburg Formation. It is approximately 250 feet thick and occurs between a subsea depth of -100 to -350 feet, which is the top of the historical common water table.

22. The production casing in these wells was set at approximately a depth of 3,775 feet and the producing Grayburg zone was drilled and completed open hole and later stimulated with acid. Very few wells were shot with nitroglycerin.

23. The original oil-water contact was found at -360 feet below sea level. The sulfur content of the Grayburg oil in this part of the field is 1.37%.

24. **Well records show that the deepest wells in this field have penetrated about 500 feet into the San Andres.** From 1934 to 1937, water encroachment into the Eunice and Monument oilfields was occurring and well documented. *See* **Goodnight Exhibit C-2**.

Modern development of the Eunice Monument South Unit (EMSU) waterflood[3]

25. Efforts to unitize the Grayburg producing zone for secondary recovery through waterflood operations began in 1979 with the early technical committee meetings among working interest owners. A plan for unitization was fully approved by the 21 working interest owners and became effective on February 1, 1985.

26. A total of $60,000,000 was allocated to this project between 1985-1987. As presented in the EMSU hearing documents under Commission Case No. 8397, the production interval targeted for waterflooding was limited to the Grayburg and Penrose formations,[4] which are dolomites with intermittent sand stringers and five separate pay zones. Below these pay zones was the lower Grayburg and San Andres formations, which are strong water drive reservoirs and prolific water producers. As explained at the EMSU hearing, the San Andres was unitized to serve as a source of water for waterflood operations.

27. The Commission's Order authorizing unitization under Order No. R-7765, included the Grayburg and portions of the lower Penrose to the base of the San Andres Formation, as the San Andres Formation was the only source available for make-up water for the waterflooding operations in the Grayburg Formation. The San Andres was also historically included in the

[3] Sources: Gulf Oil Eunice Monument South Unitization Document (1985); Chevron, 1988 and 1989 Report of Operations and Plans for Development for the EMSU submitted to BLM; Chevron SPE Paper 17221 (1991); and Chevron CORROSION 96 Paper No. 181 (1996).

[4] *See* Case No. 8397, Hrg. Tr. Vol. 2 224:22-25 ("Q: Now I understand that you will be injecting only into the Grayburg and Penrose and not the San Andres, is that correct? A: That is correct.").

Grayburg pool even though the San Andres formation did not yield any hydrocarbon production in this area.

28. **As of 1991, more than 95% of the existing wells operated by Chevron in the EMSU were drilled by 1938, so the age of these wells increases the likelihood of impacts to well integrity and corrosion issues. It also establishes that many of the EMSU's existing wells and related infrastructure may not be suitable for CO_2 injection due to their age, cementing, and well construction. Well integrity is the critical aspect of any proposed CO_2 injection operation.**

29. **Goodnight Exhibit C-3** is an exhibit I prepared showing two charts with the age of active wells in the EMSU. The top chart shows a breakdown of the EMSU waterflood injection wells by age. It shows that 90 of the 121 waterflood injectors were drilled before 1945. The bottom chart shows a breakdown of the EMSU Grayburg producing wells by age. It shows that 74 of the existing active Grayburg producing wells were drilled before 1976, with the 69 of those drilled before 1945.

30. Nearly all of these old wells were open-hole completions. The original estimate at the time of unitization was that 298 existing wells had to be worked over and deepened. Mechanical junk was encountered in nearly 25% of the wells reworked. A total of 270 old wells were reworked, as they were severely corroded and were deepened on average about 110 feet.

31. **This is direct evidence that, as of 1991, the historic Grayburg oil production wells had already been experiencing major corrosion issues even before commencement of water flooding operations using San Andres make-up water and decades before Goodnight initiated its San Andres disposal operations. The average age of these wells at the time in 1986 was approximately 50 years. The Grayburg Formation already was known to contain**

H_2S and corrosive waters. Even Grayburg oil was well documented to contain corrosive levels of sulfur.

32. **Goodnight Exhibit C-4** is a proposed completion and an analysis of Grayburg Formation production water from 1966 that was submitted as part of the original application by Rice Engineering & Operating, Inc. for their San Andres saltwater disposal well (SWD) EME SWD L-21 well (API No. 30-025-21852). **This Grayburg production water analysis from 1966 shows H_2S concentrations of 180 milligrams per liter (mg/L).**

33. The EMSU waterflood project required the drilling and completion of 49 new replacement wells. The reservoir pressures in the Grayburg Formation at the time were less than 200 psi and some secondary vugular and moldic features in both the Grayburg and San Andres formations caused severe loss-circulation problems. Since there is at least 285 feet to 463 feet of vertical separation between the bottom of the Grayburg producing zones and the top perforations in the existing Goodnight SWDs, there is no documented fracture network extending that deep into the San Andres Formation and in communication with the Grayburg Formation.

34. A total of 178 wells became injection wells for the waterflood project. Six water supply wells were drilled into the San Andres (which was even at that time an underpressurized reservoir) to depths of around 5,000 feet. The difficulty drilling these San Andres water supply wells and lost circulation issues clearly demonstrates that the San Andres reservoir was originally underpressurized even before the EMSU water supply wells began withdrawing water as make-up water for the waterflood. Had the San Andres reservoir been normally pressurized, extensive fluid flow would have been encountered during the drilling operations of these water supply wells. Extensive water withdrawal from the San Andres for make-up water for the EMSU waterflooding operations further depressurized the reservoir. The first water supply well was drilled and tested

in late 1985 and large fluid losses occurred in the Grayburg and San Andres Formations during drilling. Drilling these formations required large volumes of loss circulation material (LCM) to seal off and maintain circulation. Once drilled and producing, these six San Andres water supply wells were capable of withdrawing nearly 90,000 barrels of water per day (bwpd).

35. Up until 1991, 122 injection wells were injecting 83,000 bwpd as part of the EMSU's waterflood operations. From January 1987 through March 1989, Chevron withdrew 53,555,273 barrels from the San Andres Formation for waterflooding make-up water. Based on additional research conducted by Goodnight Midstream, the cumulative water withdrawal from the San Andres by 1991 is estimated at 172 million barrels. This data was obtained from the Chevron reports submitted in 1988 and 1989 to BLM regarding the report of operations and plans for development of the Eunice Monument South Unit, Lea County, New Mexico, and additional data obtained by Goodnight Midstream.

36. **Goodnight Exhibit C-5** is the 1986 cover letter snip from Chevron's EMSU SWD #1 San Andres saltwater disposal well (SWD) conversion application stating that "Chevron U.S.A. Inc. respectfully requests administrative approval to dispose of saltwater down the subject well into a porous formation not productive of hydrocarbons in this area." (emphasis added).

Known Scaling and Corrosion Issues[5]

37. **EMSU has historically experienced barium sulfate scale deposits in many producing oil wells prior to field unitization and initiation of the present waterflood. According to Chevron, "Years of production have severely depleted the EMSU reservoir and**

[5] Sources: Chevron, 1988 and 1989 Report of Operations and Plans for Development for the EMSU submitted to BLM; Chevron SPE Paper 17221 (1991); and Chevron CORROSION 96 Paper No. 181 (1996).

corroded the wellbores."[6] The corrosion problem was exacerbated with the waterflood due to the known incompatibility of the supply water from the San Andres and water within the producing reservoir (Grayburg Formation).

38. Scale inhibitor treatments were used by previous EMSU operators to control the barium sulfate scale depositions where analysis indicated treatments were needed. Geological mapping techniques were used to show which wells had barium sulfate scaling tendencies and water analysis data from each well in the waterflood unit were used to update this map annually.

39. As of 1996, there were 156 active producing wells and 138 injection wells on the EMSU. At that time, water injection was approximately 100,000 to 110,000 bwpd with 60,000 bwpd sourced from the San Andres water supply wells and 50,500 bwpd sourced from recycled produced water from the Grayburg.

40. The chemistry of the Grayburg produced water varies widely across the EMSU field with the northern part having about 90,000 mg/L chlorides and the southern part having about 5,000 mg/L chlorides.[7] High permeability areas in the Grayburg exist in the center and southwest section of the field and permeability declines significantly in each direction from the center of the field. Water analysis from the production wells shows barium concentrations ranging from less than 1 mg/L to 118 mg/L. Chevron water analyses from the late 1980s to early 1990s show sulfur concentrations both in the Grayburg and San Andres. The San Andres water chemistry from the water supply wells varies considerably with sulfate concentrations ranging from approximately 5

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[6] Mitchell, R.K. and Salvo, G.S. 1991. The EMSU Waterflood Project: A Case History of Infill Drilling, Completions, and Workovers. SPE Drilling Engineering Paper 17221, June 1991, page 123.

[7] Strickland, L.N., Beaty, D.W., and Carpenter, A.B. 1996. Utilization of Geological Mapping Techniques to Track Scaling Tendencies in the Eunice Monument South Unit Waterflood, Lea County, New Mexico. The NACE International Annual Conference and Exposition, CORROSION 96, Paper No. 181, page 181/2.

mg/L to 2,151 mg/L. The sulfate concentrations in the Grayburg also show variability ranging from 0 mg/L to 2,500 mg/L.

41. **If these waters from the San Andres water supply wells and Grayburg formation waters are mixed, one would expect the precipitation of barium sulfate scale deposits. The San Andres Formation provided the only source of water with sufficient volumes for the waterflood and HAD TO BE USED AS THE SUPPLY SOURCE for EMSU waterflood operations. Gulf Oil and Chevron nevertheless elected to use the San Andres as the EMSU water supply source knowing full well that the San Andres water was not compatible with the Penrose or Grayburg formation waters. Chevron production experience had strongly suggested that the mixing of waters occurs within the wellbores and not in the reservoir and that inflow of sulfate-rich water found its way into the wellbores prior to waterflood initiation. Additionally, the presence of sulfur in the crude oils could have also exacerbated this historical problem.**

42. To address these issues, Chevron developed and consistently used scale inhibitor formation squeeze treatments of 110 to 440 gallons of scale inhibitor per treatment in the Grayburg production wells. There is no discussion of scale inhibitor treatment of the make-up water from the San Andres Formation prior to injection for waterflooding operations.

43. **Chevron documented that the producing oil wells had experienced barium sulfate scale problems BEFORE the EMSU waterflood and that the EMSU continued to experience scale problems after commencement of waterflooding operations. This clearly demonstrates that scaling problems had no association with the existing San Andres SWDs or Goodnight's San Andres SWDs.**

44. Additionally, after commencement of waterflooding operations, the primary problems in the EMSU discovered by Chevron in 1998 included:[8]

- Water cycling through high-permeability streaks;
- Operations suffered from early water breakthrough, slow pressure increases, and low injection/withdrawal rates;
- Poor reservoir flood conformance reduced the waterflood effectiveness;
- Water injection into the gas cap; and
- Wellbore zonal isolation problems.

45. Chevron focused on a reservoir conformance improvement project for the EMSU. However, some of the implementation challenges included:[9]

- One common problem was behind-pipe communication due to poor cement bonding, which made achieving the designed acid and cement placement difficult;
- Isolation was also difficult in open-hole wellbores due to rugose borehole conditions and washouts around the casing shoe;
- The other problems included squeeze jobs that leaked and the failure of some casing and tubing strings that were weakened by corrosion; and
- It was difficult to get a good cement bond when iron sulfide scale was present.

46. **All of these well integrity problems identified by Chevron during this reservoir conformance improvement project clearly demonstrate the substantial regulatory challenges Empire will face attempting to permit a CO_2 tertiary oil recovery project in the EMSU.**

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[8] Love, Tracy, McCarty, Andrew, Miller, Matthew J., and Mark Semmelbeck. "Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood Conformance." Paper presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1998. doi: https://doi.org/10.2118/49201-MS.

[9] Love, Tracy, McCarty, Andrew, Miller, Matthew J., and Mark Semmelbeck. "Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood Conformance." Paper presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1998. doi: https://doi.org/10.2118/49201-MS.

Types of Corrosion[10]

47. **The main types of corrosion associated with oil and gas production is sweet corrosion (CO_2), sour corrosion (H_2S), oxygen corrosion, galvanic corrosion, crevice corrosion, erosion corrosion, stress corrosion cracking, and microbiologically induced corrosion.**

48. While CO_2 is the principal corroding agent in the oil and gas industry, the other critical corrosion agents include H_2S, oxygen, and microbial-induced corrosion, which is mainly sulfate-reducing bacteria or iron-precipitating bacteria. When CO_2 is not in the dry phase, it promotes an electrochemical reaction between the steel casing in a wellbore and the CO_2, which dissolves in the water and forms carbonic acid.[11] Not only does the carbonic acid attack the steel casing in the wells, it can also degrade the cement behind the steel casing, which would allow CO_2 migration out of the injection zone. Empire's proposal to use the water-alternating-gas (WAG) method for CO_2 tertiary oil recovery allows for the formation of carbonic acid in these wells.

49. The common form of microbial-induced corrosion causes pitting, formation of iron sulfide scale, slime, plugging, and bacterial growth.

50. The primary concern with H_2S is the attack on metal. Which leads to metal embrittlement. The presence of H_2S and low temperatures also encourages galvanic corrosion. H_2S is a premier corrosion agent.

51. Chloride corrosion is normally associated with pitting on the metal surfaces and chloride-induced stress corrosion cracking. **Compared to the other more aggressive corrosion**

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[10] Sources: International Journal of Industrial Chemistry, 2013; Corrosion and its Mitigation in the Oil and Gas Industries (2012); and Journal of Petroleum Science and Engineering 171 (2018).

[11] Popoola, Lekan Taofeek et al. 2013. Corrosion problems during oil and gas production and its mitigation. International Journal of Industrial Chemistry (IJIC), 4:35, http://www.industchem.com/content/4/1/35.

types associated with the EMSU, chloride corrosion is a minor consideration. High chloride environments are a common condition across oil and gas activities and generally not an issue. Furthermore, injection of higher chloride concentrations would be substantially diluted by the native fluids already within the San Andres Formation. More concerning than chlorides, however, is CO_2. The injection of CO_2 would increase the likelihood of more corrosion and well integrity issues in the EMSU, irrespective of chloride content, as CO_2 is a premier corrosion agent.

52. Dissolved oxygen in the formation or production water is the primary cause of corrosion on oil and gas production equipment.

53. In the oil and gas industry, scale deposition on both surface and subsurface production equipment can lead to formation damage, skin effect, loss of production, reduction in pressure, and premature failure of subsurface equipment.

54. Due to the geochemical processes associated with the injection of fluids, formation waters and rock, the complex composition of these various fluids can lead to difficulties in control of the formation of scale deposits.

55. The most common types of scale associated with the oil and gas industry are carbonate (calcium), sulfide (iron and zinc), and sulfates (calcium, barium, and strontium).

56. 38. Scale formation is one of the most severe forms of damage to the formation and iron sulfide scale is one of the most common scales associated with wells containing H_2S.

57. Both chemical and mechanical methods are employed in the oil and gas industry to remove scale deposits from wells

58. **As can be seen, corrosion issues and scale deposits typically associated with injection operations and waterflooding operations, like the EMSU, are primarily associated with CO_2, H_2S, oxygen, and microbial-induced bacteria. Chlorides have little impact on**

corrosion in the oil and gas industry and on the EMSU project in particular. Publications addressing corrosion typically do not identify chloride concentrations as a cause. It is well documented from the Chevron papers that incompatibility of the make-up water from the San Andres that existed long before Goodnight started injection operations—not chlorides—has led to the corrosion and scale issues seen at the EMSU waterflood project.

59. ***"The EMSU has historically experienced barium sulfate scale deposits in many producing oil wells prior to field unitization and initiation of the present waterflood."*[12] *"Those wells experiencing barium sulfate problems prior to the waterflood continue to experience barium sulfate scale problems."*[13]**

EMSU Water Supply Wells[14]

60. Chevron originally drilled and completed six San Andres water supply wells for the EMSU waterflood. A seventh well, EMSU #278, was originally a Grayburg producing well completed from 3,654 feet to 3,845 feet, but in 2017 XTO drilled the well back down to a total depth of 6,164 feet and set a cast iron bridge plug (CIBP) at 5,300 feet and perforated the San Andres from 4,058 feet to 4,523 feet. The EMSU #278 started producing water from the San Andres in November 2018 for injection make-up water.

61. Empire New Mexico LLC (Empire) acquired the EMSU waterflood from XTO on March 12, 2021. At the time of the acquisition, only four of the water supply wells were transferred. Two of the water supply wells had been previously plugged and abandoned by

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[12] Strickland, L.N., Beaty, D.W., and Carpenter, A.B. 1996. Utilization of Geological Mapping Techniques to Track Scaling Tendencies in the Eunice Monument South Unit Waterflood, Lea County, New Mexico. The NACE International Annual Conference and Exposition, CORROSION 96, Paper No. 181, page 181/1.

[13] Strickland, L.N., Beaty, D.W., and Carpenter, A.B. 1996. Utilization of Geological Mapping Techniques to Track Scaling Tendencies in the Eunice Monument South Unit Waterflood, Lea County, New Mexico. The NACE International Annual Conference and Exposition, CORROSION 96, Paper No. 181, page 181/4.

[14] Sources: New Mexico Oil Conservation Division records and Empire's Unit Plan Development to BLM (2024).

Chevron in 2002 and the third water supply well had been plugged back and converted to a Grayburg production well by XTO. Two of the water supply wells acquired by Empire (EMSU #457 and EMSU #458) were "temporarily abandoned." The EMSU #457 had not operated since 2004 and the EMSU #458 had not operated since 2013. In Empire's Unit Plan of Development submitted to BLM for 2023 operations, Empire reported that the EMSU A and EMSU B produce 975 barrels of oil per day (bopd), 525 mcf of gas, 89,000 barrels of water per day (bwpd), with 90,000 bwpd injected.

62. In 2023, the two Empire water supply wells, EMSU #459 and EMSU #278, were operated only 259 days and 84 days, respectively. The total volume of water withdrawals from the San Andres for make-up water for waterflooding in 2023 was 1,817,584 barrels. Total injection volumes for 2023 using the 90,000 bwpd average submitted to BLM equals 32,850,000 barrels. **This means only 5.5 percent of the water injected into the EMSU A and B units in 2023 came from the San Andres water supply wells.**

63. Goodnight requested all water chemistry data from Empire that supports their allegation that injecting produced water is impairing EMSU operations; however, Empire did not produce two key categories of water chemistry data. First, they did not produce the Chevron water chemistry data so there is no way to confirm the statements in Lindsay's testimony that San Andres water is migrating into the Grayburg. Second, they did not produce any water chemistry data associated with their water supply wells showing that Goodnight's injection is having any influence on the San Andres aquifer chemistry.

64. **There is NO reported oil production from any of these San Andres water supply wells during their operational life as water supply wells.** In 2013, XTO filed an application to allow for a small amount of gas to be flared from water supply wells EMSU #458

and #459, which indicates that the San Andres reservoir has been drawn down sufficiently to reach the bubble point and release gas.[15] **With the estimated water withdrawal of over 348 million barrels of water, there is NO producible oil from Goodnight's San Andres disposal zone that Empire claims is a residual oil zone (ROZ). Chevron, XTO, and Empire have not reported any production from this zone. If sufficient oil reserves were in the zone Empire claims is a San Andres ROZ, at the oil saturations they contend exist, some oil would have been produced in conjunction with the hundreds of millions of barrels of water withdrawn from the San Andres since 1987.**

65. **If the San Andres Formation was capable of producing oil, it would have occurred during the dewatering and depressurizing of the reservoir for the large amounts of make-up water withdrawn and used for waterflooding operations.** A good example of how dewatering of an oil reservoir scenario can be commercially viable is the Hunton Limestone in Oklahoma. However, without the significant disposal opportunities into the Arbuckle Group to handle the large amounts of produced water, this dewatering operation would not have been successful. A presentation from 2003 at the American Association of Petroleum Geologists (AAPG) Mid-Continent Section Meeting addresses this.[16] Below is the important details from this presentation:

- *"The field is unique in its manner of production; a typical well initially appears uneconomical in that it produces very large quantities of water, with some hydrocarbons. Reservoir rock in the field can best be described as a heterogeneous*

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[15] Drake, Steve Allen. 2022. Self-Affirmed Statement of Steve Allen Drake, Case No. 22626 Exhibit No. C, September 15, 2022, before the New Mexico Oil Conservation Division.

[16] Podpechan, Joe et al. 2003. Dewatering as a Production Technique in a Dual Permeability Reservoir: West Carney Hunton Field, Lincoln and Logan Counties, Oklahoma. AAPG Search and Discovery Article #90020@2003 AAPG Mid-Continent Section Meeting, Tulsa, Oklahoma, October 12-14, 2003.

system composed of an erratic distribution of "high" and "low" permeability carbonates with varying amounts of porosity. The field is made commercial only by significantly dropping reservoir pressure, allowing hydrocarbons stored in "low permeability" component of the reservoir to flow into the "high permeability" component where it can be produced efficiently. This is accomplished by pumping very large quantities of water; hundreds to in some cases thousands of barrels a day. Within days to weeks the quantity of hydrocarbons produced increases while the quantity of water produced decreases, ultimately resulting in a profitable well."[17]

- So if the San Andres Formation has hydrocarbon saturations capable of producing oil from the claimed ROZ reservoir, why hasn't any commercial quantities of oil been produced during the significant "dewatering" of the reservoir for make-up water for the Grayburg waterflooding? The dewatering and depressurization of the San Andres should have produced some quantities of oil along with the large amounts of water withdrawn from the reservoir. This has not been the case.
- Most conversions to CO_2 tertiary oil recovery operations do waterflooding first. So why is Empire proposing to go directly from NO PRODUCTION in the San Andres to CO_2 flooding?
- Additionally, if CO_2 operations did commence into the claimed San Andres ROZ, where would Empire dispose of the excessive amounts of produced water from the San Andres since this would not be a waterflood operation, but a WAG operation?

[17] Podpechan, Joe et al. 2003. Dewatering as a Production Technique in a Dual Permeability Reservoir: West Carney Hunton Field, Lincoln and Logan Counties, Oklahoma. AAPG Search and Discovery Article #90020@2003 AAPG Mid-Continent Section Meeting, Tulsa, Oklahoma, October 12-14, 2003.

Geochemical analysis of the various fluids[18]

66. Based on the Bureau of Mines Report of Investigations 3456 published in 1939, Grayburg water encroachment started in the Eunice oil field between 1934-1937.

67. The appearance of water in any area of the field is influenced locally by the total depth of the wells.

68. In the area in the oil field subject to water documented encroachment, the deeper wells produced water first if the well depths are drilled into a porous and permeable formation connected to the source of water. At that time, the water drive was most active at the southwestern part of the oil field. Hence the upward movement of the oil-water contact from -360 to -325 feet below sea level.

69. **If there was any impact to the Goat Seep aquifer from water being drawn into the Grayburg Formation, that would have occurred during primary oil production. The depressurization of the Grayburg reservoir that created a cone of depression around the EMSU, would have allowed Goat Seep aquifer water migration into the Grayburg prior to waterflooding operations. Any contamination of the Goat Seep aquifer would have occurred long before any Goodnight injection operations.**

70. Based on the assessments of both the SPE 1991 Chevron paper and the 1996 Chevron paper, it is very well documented that corrosion and barium sulfate scaling occurred long before unitization of the EMSU and commencement of waterflooding in 1987.

71. Existing corrosion and barium sulfate scaling, discussed above, were additionally exacerbated by the usage of make-up water from the San Andres Formation for waterflooding and

[18] Sources: Bureau of Mines RI 3456 (1939); Chevron SPE Paper 17221 (1991); and Chevron CORROSION 96 Paper No. 181 (1996).

the known compatibility issues of intermixing of the Grayburg formation waters with injected make-up water from the San Andres Formation that existed well before Goodnight commenced its injection operations.

72. Water chemistry in the EMSU production wells from 1996 shows barium concentrations ranging from 1 mg/L to 118 mg/L and concentrations of sulfate from the San Andres was approximately 2,800 mg/L.

73. Chloride chemistry in the Grayburg-produced waters ranges from approximately 5,000 mg/L to 90,000 mg/L depending on location within the field.[19] Higher chlorides increase the total dissolved solids (TDS) and specific gravity of the fluid, which lowers the surface injection pressures at the enhanced oil recovery injection wells. SWDs across the U.S. routinely inject higher salinity fluids associated with production brines from conventional oil and gas wells.

74. It was well documented in the Chevron 1991 SPE Paper that H_2S and corrosive waters were present before waterflooding and evidence from earlier publications showed the crude oil produced from the Grayburg contained over 1% sulfur. As a result, Chevron was required to perform substantial work on the wells in the EMSU. ***"In total, 298 wells required cleaning out, deepening, and remedial work. The average age of these wells was 50 years, and all contained H_2S and corrosive waters".***[20]

75. Chevron successfully developed chemical treatment processes to address not only the iron sulfide and barium sulfate scaling they also addressed the associated corrosion issues in

[19] Strickland, L.N., Beaty, D.W., and Carpenter, A.B. 1996. Utilization of Geological Mapping Techniques to Track Scaling Tendencies in the Eunice Monument South Unit Waterflood, Lea County, New Mexico. The NACE International Annual Conference and Exposition, CORROSION 96, Paper No. 181, page 181/2.

[20] Mitchell, R.K. and Salvo, G.S. 1991. The EMSU Waterflood Project: A Case History of Infill Drilling, Completions, and Workovers. SPE Drilling Engineering Paper 17221, June 1991, page 118.

the EMSU. Additionally, Chevron conducted annual sampling events at all production wells to map scaling progress.

76. **It is unknown what type of chemical treatment or whether Empire continued the same chemical treatment previously done by Chevron and XTO after Empire acquired the EMSU waterflood in 2021.** In response to discovery requests, Empire claims to not have any documents related to previous chemical treatment utilized by either Chevron or XTO at the EMSU waterflood.[21] It is surprising to me that Empire would acquire and assume operations of a waterflood like the EMSU that has a long history of known scaling and corrosion issues with wells that are more than 70 years old without knowing the chemical treating and corrosion-prevention plans that had been in place previously and whether those treatments were part of a systematic program.

77. In discovery, Empire did provide current chemical treatment protocols provided by Coastal Chemical Co., Inc., which utilized scale inhibitor and biocide and some other additives, indicating that Empire initiated some form a systematic treatment program. **Empire's treatment protocol apparently started only as recently as February 2022 based on the records supplied by Empire, despite the fact the EMSU has a long history of known corrosion and scaling issues. Based on my understanding, Empire took over operations of the EMSU in 2021, so there appears to have been a gap of at least a couple years in the implementation of a systematic corrosion prevention and treatment program at the EMSU or longer because we have no records from the previous operator.**

78. **As noted above in footnote 1, after confirming in a discovery response on August 1, 2024 that "it has conducted a diligent and thorough search of the records within**

[21] See footnote 1.

its possession, custody, or control and discovered no responsive documents" related to a request for prior operator corrosion prevent and treatment On August 21, 2024, Empire provided a supplemental response that included a spreadsheet Bates OCD 23614-17 03648 containing descriptions of individual chemical treatments for various wells in the EMSU going back in time from 2023 to 1939. However, I have not had time to fully review this supplemental information to incorporate it into my analysis and assessment and reserve the right to amend or supplement this statement after I have had a reasonable opportunity to review the new information.

79. Empire's corrosion treatment protocols do not include discussion on any filtering or actual individual well chemical treatment, so it is unknown if Empire had changed the previous chemical treatment operations of Chevron or XTO. Based on my experience, it is not uncommon for a new acquirer of injection well or waterflood operations to reduce costs by modifying or altering previous successful chemical treatment operations to address the bacteria, corrosion, and scaling issues.

80. Goodnight Midstream's geochemical analysis of the San Andres Formation fluids collected from five of its saltwater disposal wells (SWDs) conducted during swabbing tests shows the following range of concentrations of chemical constituents:

- Total dissolved solids (TDS) ranged from 19,000 mg/L to 46,700 mg/L;
- Chloride concentrations ranged from 8,900 mg/L to 24,200 mg/L;
- Sulfate concentrations varied from 1,830 mg/L to 2,830 mg/L, which clearly falls within the sulfate range of Chevron's analysis in their 1996 paper; and
- Barium concentration (analyzed on only one SWD) was 0.148 mg/L, which is below the barium concentration range from the 1996 Chevron paper.

81. Injection of production waters from other producing formations would intermix with the existing native fluids within the San Andres Formation and dilute any higher TDS or higher chloride waters. Additionally, as discussed above in the Corrosion Section, chlorides are a minor corrosion issue compared to the other known corrosion agents already in the EMSU Grayburg reservoir.

Goodnight Midstream Chemical Treatment and Filtering of Injected Fluids

82. Typical saltwater disposal well operations (such as Goodnight Midstream's SWDs) include chemical treatments and filtering of produced fluids prior to injection to reduce bacteria, solids, and scaling issues.

83. To ensure a complete treatment of produced and flowback fluids from production wells Goodnight Midstream Permian, LLC (Goodnight Midstream) uses a combination of chemical treatment and filtering to address potential scaling and corrosion issues associated with the fluids injected from production wells.

84. Currently, Goodnight Midstream treats the produced fluids with four different chemicals:

- Halliburton MC M-82800 – Scale Dissolver,
- Halliburton MX8-2248 – Iron Sulfide Dissolver,
- Halliburton MC S-2510T – Scale Inhibitor, and
- Halliburton MC SS-5260 – Acid Surfactant.

85. Goodnight Midstream's chemical treatment is performed twice at the injection points (inlets) at their eight facilities and tank battery.

86. The produced fluids are chemically treated a third time at their centralized injection facility with a combination of chemicals including a scale inhibitor, acid surfactant, and iron

sulfide inhibitor. The scale inhibitor and dissolver are used to dissolve and inhibit carbonate and sulfide scales along with the acid to assist in dissolving of scale deposits.

87. Coarse filtering is done at Goodnight Midstream's saltwater disposal wells (SWDs) with rock baskets and 100-micron filtering to remove any objects in the fluid stream.

Goodnight Midstream Existing San Andres SWDs

88. Goodnight's SWDs are typically stimulated with 15% hydrochloric acid (HCL) using between 5,000 to 20,000 gallons as needed to reduce any formation skin damage and friction issues downhole. Additional additives to the acid job included corrosion inhibitor, iron reducer and iron controller, acid stabilized and acid inhibitor, surfactant, and non-emulsifying agent. Additionally, echometers are used twice a year on each SWD to obtain fluid levels.

89. These SWDs go back on vacuum within about 60 seconds after shutdown indicating that injection pressures are related to friction and not formation pressurization.

90. Typical fluids injected include produced water and flow back water from Avalon Shale, Bone Spring, and Wolfcamp formations. TDS of these fluids range from approximately 130,000 mg/L to 180,000 mg/L.

91. **All of the existing Goodnight Midstream San Andres SWDs are completed from approximately 285 feet to 463 feet deeper than the lower-most perforation or total depth of the open hole of any existing Grayburg producing or injection well in the EMSU. Additionally, according to Steve Drake's self-affirmed statement and cross section exhibits from 2022, there is not only a low-porosity and low-permeability barrier that separates the producing zones in the Grayburg from the disposal zone in the San Andres, but there are also anhydrites directly above the top of the Goodnight's injection zones in their San Andres**

SWDs, which provides additional low-porosity and low-permeability barriers that would prevent upward fluid migration out of Goodnight's SWDs.[22]

EMSU Evaluation and Assessment[23]

92. Since the commencement of the EMSU waterflood in 1986, Chevron and XTO drilled 112 new Grayburg injection and production wells on the EMSU property.

93. Out of these 112 wells, 46 wells penetrated into or through the San Andres Formation (several wells penetrated the Glorieta Sandstone).

94. Out of these 46 wells that looked to have penetrated the San Andres based on the operators' reported San Andres picks, both Chevron and XTO attempted to produce from at least eight of these wells that were completed and perforated in both the Grayburg and San Andres formations. None of these wells produced commercial quantities of oil from the San Andres and all of these wells were plugged back by Chevron or XTO into the Grayburg Formation.

95. After attempting to produce both the Grayburg and San Andres in these eight wells, the lower Grayburg and San Andres perforations were sealed off with a Cast Iron Bridge Plug (CIBP) due to excessive water production in all eight wells.

96. One of these eight wells was a waterflood injection well that was completed in the San Andres Formation and then plugged back with a CIBP.

97. Once waterflooding operations commenced in 1987 to 1988, most of the wells were injecting into the Grayburg Formation with no pressure or were on vacuum, indicating that the Grayburg Formation had been depressurized by primary production operations.

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[22] Drake, Steve Allen. 2022. Self-Affirmed Statement of Steve Allen Drake, Case No. 22626 Exhibit No. C, September 15, 2022, before the New Mexico Oil Conservation Division.

[23] Source: New Mexico Oil Conservation Division records and Lindsay (2014) Ph.D. dissertation.

98. Prior to initiation of waterflooding operations, the Grayburg Formation had become underpressurized. As waterflooding operations continued, the Grayburg Formation has been re-pressurized with the injection of over one billion barrels of fluid from at least 157 injection wells.

99. Additionally, the withdrawal of over 340 million barrels of make-up water from the San Andres Formation for waterflooding operations accelerated the de-pressurization of the San Andres reservoir.

Barriers to Goodnight Midstream SWD fluids migrating into the Grayburg Formation[24]

100. It is well documented with porosity and resistivity geophysical logs that the top of the San Andres Formation is fairly tight with low porosities and high resistivities. This zone would act as a barrier against upward fluid migration and is confirmed by Lindsay's Ph.D. dissertation as a geologic seal.

101. According to Lindsay's PhD dissertation (2014) regarding the reservoir seal:[25]

> **It has been found that the composite sequence boundary at the top of the Upper San Andres Formation acts as a reservoir seal and does not allow fluids to communicate with Grayburg Formation fluids. The ultimate test has come from pressure data that shows one pressure system associated with the Upper San Andres Formation and a different pressure system associated with the Grayburg Formation. The reason why the composite sequence boundary is not a porous pathway from the Upper San Andres Formation up section into the Grayburg Formation is explained by subaerial exposure and karstification associated with the Upper San Andres Formation was cemented to form a tight non-porous interval of strata.**

102. **Additionally, Lindsay (2014) states that "A key feature is that the Upper San Andres Formation composite sequence boundary that separates Upper San Andres**

[24] Sources: New Mexico Oil Conservation Division records and Lindsay PhD dissertation (2014).

[25] Lindsay, Robert Forrest. 2014. Grayburg Formation Reservoir-Scale Architecture and Sequence Stratigraphy Permian Basin, USA. Doctor of Philosophy, University of Aberdeen.

Formation porous dolostones from the overlying Grayburg Formation porous dolostones forms a significant barrier (aquiclude) to fluid flow." This is further supported by Steve Drake's self-affirmed statement from Case No. 22626.[26]

103. Even if the fracture network that Lindsay theorizes does exist, because the Grayburg Formation has been re-pressurized and the San Andres Formation de-pressurized, any Goodnight Midstream SWD injection fluids into the San Andres would not migrate upward since the San Andres Formation is now underpressurized. But, as discussed below, there is no evidence of any fractures that compromise the seal between the two formations, as confirmed by the sustained pressure differential.

104. In order for the San Andres reservoir to even start re-pressurization, all of the pore space in the reservoir would need to be refilled to accommodate the reconstructed estimate that over 340 million barrels of water has been withdrawn from the San Andres Formation within the EMSU alone.

105. Additionally, the top perforations in the San Andres Goodnight Midstream SWDs range from 285 feet to 463 feet below the lowest producing intervals in any of Empire's Grayburg production wells. This vertical separation, comprised of tight intervals with low porosities and high resistivities with anhydrites immediately above the top of the injection zones, would serve as additional barriers to vertical fluid migration into the Grayburg Formation.

106. Moreover, the injected fluids from the Goodnight Midstream SWDs would intermix with the existing native brine in the San Andres Formation, substantially diluting the TDS and chloride concentrations.

[26] Drake, Steve Allen. 2022. Self-Affirmed Statement of Steve Allen Drake, Case No. 22626 Exhibit No. C, September 15, 2022, before the New Mexico Oil Conservation Division.

Fractured Carbonate Reservoirs[27]

107. According to Nelson (2001), Fractures are often present in the rocks, but fractures are most often distributed throughout the rocks in an ineffective manner with respect to reservoir fluid flow. Additionally, fractures are very compressible and as the reservoir pressure is reduced, these fractures will close up or become plugged due to the depressurization.

108. I have previously documented fracture flow in carbonate rocks in quarries in Ohio. This work has shown that fluid flow typically moves vertically along fractures, but when the fluid encounters bedding planes, the fluid flow then migrates horizontally and does not continue upward. **Goodnight Exhibit C- 6** is a classic example of fluid flow in fractured carbonate rocks which clearly demonstrates that bedding planes in the rocks, such as the tight intervals with low porosities and high resistivities found at the top of the San Andres, act as barriers to upward fluid flow.

109. Once depressurization of fractured carbonate rocks occurs, fluid flowing through these fractures causes mineralization or plugging, which eventually leads to the dewatering of the fracture system.

110. Based on my extensive experience and expertise with subsurface downhole video observations of both groundwater flow and natural gas migration in water wells, it is my opinion that horizontal bedding planes serve as barriers to fluid and natural gas flow in the subsurface. **Goodnight Exhibit C-7** is another example in an Ohio quarry showing how groundwater flow in fractured carbonate rocks is affected by a horizontal bedding plane, which serves as a barrier to upward fluid flow.

111. The fracture network within the EMSU clearly shows it is limited in extent to areas of high permeability and are documented to extend only short vertical distances, making them

[27] Sources: Tomastik and Benko (2007), Lindsay (2014) PhD dissertation, and Nelson (2001).

insufficient to serve as a communication pathway between the Grayburg and San Andres formations. There is no evidence of an extensive fracture network or faulting in the Grayburg and San Andres formations across the EMSU that can serve as pathway for communication.

112. Lindsay's 2014 PhD dissertation states

> *There have been places found in EMSU, EMSUB, and AGU where faults/fractures have allowed Upper San Andres Formation fluids to move up section into Grayburg Formation strata, which form vertically oriented plumes of Upper San Andres Formation water within the Grayburg Formation. These localities tend to be ONLY associated with one well, indicating that faults/fractures are localized in small areas.*

113. Additionally, in Goodnight's C-108s for their pending SWD applications, it stated that Goodnight had acquired and evaluated 3-D seismic in the area and there were no faults seen in the Artesia Group, San Andres, Glorieta, or Leonard Series of rocks.

114. While there is no data supporting Lindsay's statement documenting San Andres formation fluids moving into the Grayburg formation, this statement clearly shows that, to the extent fractures exist, there are limits to any fracturing in the Grayburg and San Andres formations. The fracture study that Lindsay refers to in his testimony is limited to one well—the EMSU #679—and was limited to the Grayburg zones 4, 5 and the upper half of 6. The study reported a maximum vertical fracture length of 1-3 feet, far short of what would be required to reach the San Andres. So, the alleged fractures relied on by Lindsay appear to be limited to a single well and were not observed to extend into the San Andres.

115. Additionally, since the top of the San Andres injection zones in the Goodnight Midstream SWDs are between 285 feet to 463 feet deeper than the deepest perforations in the EMSU production or injection wells in the Grayburg Formation. **There would be no vertical fractures extending from this depth in the San Andres Formation and up into the Lower Grayburg Formation.**

<u>Conversion of the San Andres to CO2 Enhanced Oil Recovery</u>
<u>Will Require Substantial and Costly Upgrades</u>[28]

116. Empire's experts and technical staff have claimed the existence of a residual oil zone (ROZ) in the San Andres Formation and that Empire plans on injection of CO_2 into the San Andres for tertiary oil recovery. To develop a further understanding of Class II EOR CO_2 injection in New Mexico, a review was conducted on both the South Hobbs and North Hobbs Grayburg-San Andres waterfloods that were converted by Occidental Permian Limited Partnership (OXY) from waterflooding operations to CO_2 tertiary oil recovery projects in 2013 and 2014. Both of these projects were existing waterfloods.

117. The South Hobbs Grayburg-San Andres conversion to CO_2 injection included a number of OXY presentations (Case No. 14981) in their application.

118. Even though it was permitted as Grayburg-San Andres injection interval, injection was limited to the upper few hundred feet of the San Andres.

119. Injection included water-alternating-gas (WAG) injection with estimated daily injection rates of 115,000 bwpd, 45 million cubic feet (MMCF) of CO_2, and maximum reinjection of CO_2 and produced gases, including H_2S at 75 MMCF.

120. This project required an extensive area of review (AOR) analysis and potential corrective action for wells in the AOR given the plan to inject CO_2, produced H_2S, and water, which in combination can be highly corrosive.

121. **<u>Goodnight Exhibit C-8</u>** shows that the total project capital costs for the South Hobbs Grayburg-San Andres project in 2013 was $312 million dollars, with $246 million capital costs for additional facilities.

[28] Sources: New Mexico Oil Conservation Division records.

122. Similarly, the North Hobbs Grayburg-San Andres conversion to CO_2 included a number of OXY presentations (Case No. 15103) in their application.

123. The North Hobbs conversion project to CO_2 was for injection into both the Grayburg and San Andres formations.

124. Injection included water-alternating-gas (WAG) injection with estimated daily injection rates of 300,000 bwpd, 100 million cubic feet (MMCF) of CO_2, and maximum reinjection of CO_2 and produced gases including H_2S at 150 MMCF.

125. As with the South Hobbs Project, the North Hobbs Project required an extensive area of review (AOR) analysis and potential corrective action of wells in the AOR due to the plan to inject CO_2, produced H_2S, and water. This involved the conversion of 30 existing wells to CO_2 injectors and the drilling of 23 new CO_2 injection wells, of which, 17 were proposed to be directionally drilled.

126. **Goodnight Exhibit C-9** shows that the total project capital costs for the North Hobbs Project in 2014 was $425 million dollars, of which $280 million was capital cost for additional facilities.

127. OXY proposed to convert 22 existing wells to CO_2 injection and to drill and complete 141 new injection wells for the North Hobbs CO_2 project.

128. Review of OXY's case files, well construction, and operating plans in these cases are instructive in the context of these cases. Based on my experience, review of the OXY case materials, and the condition and vintage of EMSU's existing wells, Empire Petroleum Corporation's claim to convert the Grayburg and San Andres to CO_2 flooding would require extensive re-working of wells and well integrity challenges, the drilling of many more new wells, potential changes to injection tubing and packers, and a tremendous amount of capital expenditure

to move from waterflooding to CO_2 injection for tertiary recovery of oil from both Grayburg Zones 3, 4,and 5 and the entire San Andres ROZ.

129. For example, in both the North Hobbs Project and the South Hobbs Project OXY was required to install expensive safety devices and costly anti-corrosion equipment in each of its injection wells. OXY was required to install one-way safety valves at the surface of all injection wells to prevent flow-back of injected gas during an emergency, start-up or shut-down operations. *See* **Goodnight Exhibit C-10** (Order No. R-6199-F). It was also required to install fiberglass-lined tubing and a nickel-plated packer. The annulus of the injection wells had to be filled with an inert packer fluid containing biocide and corrosion inhibitors, and a gauge or approved leak-detection device was required to be attached to the annulus to determine leakage in the casing, tubing or packer. Cement bond longs were required to confirm the quality of the cement for all injection wells and OXY was required to use special anti-corrosive cement on all new injection wells. *See* **Goodnight Exhibit C-11** (Order No. R-4934-F). A supervisory control and data acquisition (SCADA) was also required to be installed in each injection well for real-time monitoring of pressures, temperature, water content, and gas content. These are among just a few of the types of extensive updates and costly upgrades Empire will likely have to implement to convert to a CO_2 EOR project.

130. Additionally, I have also performed an evaluation of Empire's document entitled "Eunice Monument & Arrowhead Field CO_2 Development Plan dated January 15, 2024 (Bates No. OCD-23614-17 03483)."[29] In that plan, Empire is proposing only drilling and completing 10 new wells and plugging and abandoning only 15 wells. There are currently 214 wells (111

[29] Davis, Darrell W. 2024. Eunice Monument & Arrowhead Field CO_2 Development Plan, Lea County, New Mexico. Memo to File, January 15, 2024.

producers and 103 injectors) in the EMSU field, and all these wells would require a complete well integrity assessment as to its depth, well construction, completion, and cement. Far more technical considerations would need to be undertaken in regard to this proposal than is provided or contemplated in Empire's plan. Additionally, Empire claims it will focus on CO_2 flooding of Grayburg zones 3, 4, and 5 and the entire San Andres ROZ, however, there is no discussion on how this would be accomplished with reworking of existing wells, many of which date from the late 1930s and present serious well integrity and safety issues, particularly with the known corrosion issues associated with the EMSU. Empire claims estimated costs will be approximately $123 million. My first question is whether Empire has access to this kind of funding. Even if Empire does have access to some funding, Empire's estimated costs for its project are substantially off the mark in comparison to OXY's CO_2 work in the North and South Hobbs fields in 2013-2014. OXY's total cost estimates for both fields exceeded $700 million—not accounting for inflation.

131. **Empire's proposed CO_2 EOR for the EMSU is seriously lacking in both detailed technical considerations and would be substantially underfunded based on this proposed document. Empire's plan does not appear credible, especially with respect to Goodnight's San Andres disposal zone because only a few of EMSU's existing wells are deep enough to even penetrate the San Andres.**

132. Empire has stated that it plans to develop the San Andres interval using the same facilities it will use to develop the main pay zone of the Grayburg. However, it remains unclear how Empire could successfully utilize its existing Grayburg injection wells for a Grayburg-San Andres CO_2 flood, when a majority of its wells are more than 80 years old and are documented to have been exposed to corrosive conditions for decades and are not deep enough to target the San

Andres. In order to meet the Division's rigorous Class II UIC injection well requirements, it is more likely that Empire will be required to drill new injection wells for its proposed Grayburg-San Andres ROZ project. That will add substantial additional costs.

133. 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 8/23/2024

Thomas E. Tomastik Date

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Tom Tomastik

Chief Geologist and Regulatory Specialist

Education

B.S., Geology, Ohio University, 1979

M.S., Geology, Ohio University, 1981

Professional Registrations

Certified Petroleum Geologist: American Association of Petroleum Geologists #6354

Distinguishing Qualifications

Mr. Tomastik is a certified petroleum geologist with over 42 years of diverse expertise and experience in the energy sector, government, and consulting. He has been involved in the planning, permitting, drilling, and development of oil and gas and Class II saltwater disposal wells, Class I, III, and Class VI injection well feasibility studies, injection well audits, stray gas investigations, natural gas and natural gas liquids storage, groundwater dewatering and contamination cases, induced seismicity, seismic monitoring and installation, and expert witness testimony regarding injection wells, permitting, plugging and abandonment of oil and gas and injection wells, and groundwater investigations.

Over the last 10 years with ALL Consulting, Mr. Tomastik has been involved with both Class II and Class I non-hazardous injection wells including geological evaluation and injection zone assessment; groundwater investigations, preparing plugging plans, permitting oversight and review; well design and well construction; geophysical log interpretation; and preparing cost estimates for authorization for expenditure (AFE) for the permitting, drilling and completion of Class II and Class I non-hazardous multiple injection wells in the Indiana, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming.

Additionally, Mr. Tomastik has been an expert witness regarding induced seismicity, and has participated in seismic monitoring and installation of local networks and the development of seismic monitoring and mitigation plans, and as an expert in alleged injection well impacts to production wells for injection well clients. Mr. Tomastik currently serves as a member of the Ground Water Protection Council (GWPC) and Interstate Oil and Gas Compact Commission's (IOGCC's) national State Oil & Gas Regulatory Exchange Induced Seismicity Workgroup and GWPC's Class VI Workgroup.

Prior to working for ALL Consulting, Mr. Tomastik worked for 25-1/2 years with the Ohio Department of Natural Resources (ODNR), Division of Mineral Resources Management and the Division of Oil and Gas Resources Management (DOGRM) in the Technical Support Services Section and Underground Injection Control (UIC) Section. As senior geologist, he oversaw the

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-1
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

planning, permitting, drilling, and conversion of Class II and Class III injection wells using hydrogeology, geology, and engineering specialization for well construction, completion, and surface facility construction of these operations. Additionally, as lead geologist for the divisions, Mr. Tomastik conducted several hundred alleged groundwater and stray gas investigations related to oil and gas, industrial minerals mining, and coal mining operations in Ohio. Mr. Tomastik served on numerous occasions as DOGRM's technical expert and witness on injection wells and groundwater investigations before the Ohio Oil and Gas Commission and the Ohio Reclamation Commission and in a number of civil cases before various Ohio county court systems. Mr. Tomastik conducted reviews and provided comments on Ohio Environmental Protection Agency (EPA) permits-to-operate (PTOs) and land ban petitions related to Class I injection wells in Ohio and reviews and comments on new Class V permit applications for Ohio EPA. Mr. Tomastik also served on several national workgroups, including the U.S. EPA UIC National Technical Workgroup, GWPC Carbon Geosequestration and Hydraulic Fracturing committees, and U.S. EPA Hydraulic Fracturing Technical Workshop on Well Construction/ Operation and Subsurfacing Modeling. Mr. Tomastik also served on the Ohio Oil and Gas Association's Induced Seismic Workgroup, which addresses regulatory development of permit conditions for managing potential induced seismicity related to hydraulic fracturing and Class II injection operations in Ohio.

In the 1980s, Mr. Tomastik worked as a consultant involved in the exploration and development of oil and gas wells and Class II injection wells in Ohio with oversight of drilling, cementing, geophysical logging, sample collection and analysis, stimulation and completion, and hydraulic fracturing of these wells. Additionally, he prepared geologic maps, cross sections, and geologic reports for investor-oriented drilling programs. Mr. Tomastik also worked occasionally as a roustabout and pumper and plumbed up wellheads, installed gas pipelines, conducted plugging operations, and produced oil and gas wells.

Relevant Experience

The following information is intended to demonstrate Mr. Tomastik's experience and qualifications:

For Oliva Gibbs LLP, Mr. Tomastik was recently hired as an expert witness on an upcoming Class II saltwater injection well litigation case before the Ohio Oil and Gas Commission against the Ohio DNR, DOGRM.

For K&H Partners LLC (Tallgrass Energy), Mr. Tomastik has prepared plugging applications and plugging plans for three Class II saltwater injection wells in southeastern Ohio.

For Elmore & Elmore, Mr. Tomastik is serving as an expert on a plugging well operation and upcoming civil litigation case in Jackson County, West Virginia.

For the American Landfill, Mr. Tomastik was the project manager and performed field oversight of the installation of the cellar and tinhorn and then the conductor casing for a Class I non-hazardous injection well in Waynesburg, Ohio.

For Goodnight Midstream Permian LLC, Mr. Tomastik serves as an expert for the upcoming New Mexico Oil Conservation Division hearing regarding potential impacts to correlative rights of a waterflood operation in proximity to Goodnight Midstream's Class II saltwater disposal wells.

For Waterbridge Stateline, LLC, Mr. Tomastik has conducted geological assessments for Class II saltwater disposal wells and recommended injection zones in Lea County, New Mexico.

For DeepRock Disposal Solutions, Mr. Tomastik was the onsite expert to oversee the well workover of a Class II saltwater disposal well in Ritchie County, West Virginia.

For Purpose Energy, Mr. Tomastik prepared a geological assessment and evaluation for a potential new Class I injection well in western Ohio.

For DeepRock Disposal Solutions, Mr. Tomastik oversaw the shooting of 10 miles of 2D Seismic Reflection Survey for a Class I non-hazardous permit-to-drill application.

For K&H Partners (Tallgrass), Mr. Tomastik served as an expert witness on the ligitation case where Ohio DNR, DOGRM has suspended injection operations at the K&H injection wells in southeastern Ohio over allegations of brine migration. Mr. Tomastik testified as K&H Partner's expert on groundwater investigations and geology before the Ohio Oil and Gas Commission hearing on December 5-6, 2023.

For Spur Energy Operating LLC, Mr. Tomastik has conducted detailed geologic and well construction investigation for 8 gas pressure maintenance injection wells in New Mexico.

For Northwood Energy, Mr. Tomastik conducted a groundwater investigation of alleged brine impacts from a production facility and an injection well facility in Noble County, Ohio. Now serving as an expert witness on this case as it moves forward.

For Waterbridge Stateline, LLC, Mr. Tomastik has provided geologic expertise in selection of potential injection zones and wellbore designs for Class II SWDs in New Mexico.

For Republic Services, Mr. Tomastik performed a geologic assessment for a potential Class II SWD in south Texas and prepared hydrogeologic investigation for a Texas Railroad Comission Hearing.

For DeepRock Disposal Solutions, LLC, Mr. Tomastik recently completed a Class I nonhazardous injection feasibility study in two counties in southeastern Ohio and submitted a seismic reflection work plan that was approved by Ohio EPA.

For Crowe & Dunlevy, Mr. Tomastik is one of the experts on a litigation case in Oklahoma regarding the allegations of a saltwater purge caused by an existing Class II saltwater disposal well.

For DeepRock Disposal Solutions, LLC, Mr. Tomastik is involved in an investigation of allegations of four oil and gas wells impacted by injection operations at a Class II saltwater disposal well in Ritchie County, West Virginia.

Tom Tomastik

For Empire OH-SWD I, LLC, Mr. Tomastik was involved in the development of the AFE, selection of subcontractors, oversight of all logistics of these wells including installation of the sound barriers, secondary containment, and 24/7 drilling and completion of two Class IID saltwater injection wells in Union Township of Belmont County, Ohio.

For American Water Management, Mr. Tomastik testified as an expert witness on the saltwater injection well litigation case *State ex rel. AWMS Water Solutions, L.L.C. v. Mertz* in the Court of Appeals for Trumbull County, Ohio.

For McKim & Creed, Mr. Tomastik evaluated two SWD permits and made recommendations on well construction and completion methods in east Texas for Trinity Operating.

For Strassburger McKenna Gutnick & Getsky through the Round Table Group, Mr. Tomastik has been retained as an expert witness on the plugging litigation case Keystone Wireline, Inc. v. Traditions of America, LP and TOA Richland, LLC d/b/a Traditions of America in the Court of Common Pleas in Allegheny County, Pennsylvania. Mr. Tomastik has so far produced a technical memo for the law firm and the case is ongoing.

For a confidential client, Mr. Tomastik is involved with ALL Consulting in an oil and gas litigation case in Texas. This case is ongoing.

For Vista Disposal Solutions, Mr. Tomastik is involved with ALL Consulting on technical evaluation and remedial work being performed on a Class IID saltwater disposal well in Oklahoma.

For Omni Energy, Mr. Tomastik was involved with the drilling and completion of two Class IID saltwater injection wells in Richland Twp. of Belmont County, Ohio. Mr. Tomastik oversaw the completion of these wells including all geophysical logging, perforating, acid jobs, and step-rate injectivity testing.

For Allstate Disposal, Mr. Tomastik has prepared five Class IID saltwater injection well applications for Belmont and Monroe Counties, Ohio. Applications have been submitted to the State of Ohio.

For DeepRock Disposal Solutions, LLC, Mr. Tomastik performed an acid job and step-rate injection test on the Ritchie Hunter #2 injection well in Ritchie County, WV.

For Overflow Energy, LLC, Mr. Tomastik testified at hearing as an expert on injection wells before the New Mexico Oil Conservation Division regarding Overflow's Rita SWD #1 saltwater injection well.

For FQ Energy Services, LLC, Mr. Tomastik submitted a well workover permit application for the Ritchie Hunter #2 saltwater disposal well to WV DEP to perform an acid job and step-rate test on the well.

For Anthem Land and Water, Mr. Tomastik has worked on multiple saltwater disposal applications in Eddy and Lea Counties, New Mexico.

For Omni Energy, Mr. Tomastik participated in and submitted affidvaits to the Ohio Supreme Court regarding the litigation by Omni Energy versus the Ohio Department of Natural Resources (ODNR) and Division of Oil and Gas Resources Management (DOGRM). The Ohio Supreme Court ruled in Omni Energy's favor and the two saltwater injection permits were issued by DOGRM.

For DeepRock Disposal Solutions, LLC, ALL prepared and applied for a Waste Facility Permit for the treatment and solidification of oilfield wastes at the Deep Rock injection facility in Marietta, Ohio.

For Waste Management's American Landfill, has prepared a seismic reflection survey work plan and has prepared a Class I non-hazardous injection well permit application to inject leachate from the landfill at their site in northeastern Ohio. In January of 2022, Mr. Tomastik submitted a Class I permit-to-drill application for the American Landfill, Inc. to Ohio EPA. The Permit-to-Drill application has been issued and is moving forward to permit the well in the fall of 2023. This project is ongoing.

For Blackbuck Resources, Mr. Tomastik is involved with development of a seismic monitoring and mitigation plan and has presented this plan to the Texas Railroad Commission for a Class II saltwater disposal well application in West Texas.

For Marathon Oil, Mr. Tomastik testified at a Texas Railroad Commission Hearing on behalf of Marathon on the proposed new saltwater disposal well in the Eagleford play in south Texas.

For Allstate Disposal, Mr. Tomastik has provided expertise on a proposed conversion of a well to injection in West Virginia.

For FQ (Fountain Quail) Energy Services, Mr. Tomastik has provided expertise addressing allegations of possible injection well communication in West Virginia and completed a plugging plan and application and submittal of the application for an existing injection well in Ohio.

For a confidential client in Ohio, Mr. Tomastik has performed a geological evaluation and assessment for a new saltwater injection well in northeastern Ohio.

For Redbird Development LLC, Mr. Tomastik compiled the AFE and provided oversight of the drilling and completion of the Redbird #5 saltwater injection well in the Bass Islands Dolomite in Washington County, Ohio.

For Redbird Development LLC, Mr. Tomastik has provided a technical memo to address allegations of possible injection well communication with surrounding shallower production wells. Mr. Tomastik oversaw the plugging of a shallow Berea Sandstone near the injection well and also the plugging off of the Ohio Shale injection interval.

For Produced Water Transport, Mr. Tomastik provided expertise in the filing of new ownership documents in Ohio and assisted in the acquisition of two existing Class II saltwater disposal wells (SWDs) in Ohio for Produced Water Transport.

For PRB Water Holdings, Mr. Tomastik has evaluated several different geological formations in the Powder River Basin in Wyoming for Class I disposal and has completed wellbore design and geological assessment on two Class I applications.

For Republic Services, Mr. Tomastik has provided technical expertise in the evaluation of drilling and completion for two locations for Class I wells in Texas. Additionally, Mr. Tomastik provided expertise to evaluate the potential for induced seismicity in the area and has completed preliminary cost estimates to do this Class I project.

For Vista Disposal Solutions, Mr. Tomastik has testified as an expert witness before the New Mexico Oil Conservation Division at a hearing regarding SWD locations and geological evaluation. Mr. Tomastik also participated on completion of 12 SWD applications and provided wellbore design and geological evaluation for these Class II applications. Furthermore, he completed an in-depth analysis of the potential for shallower-zone injection in New Mexico and five SWD applications have been submitted for this zone.

For Marathon Oil, Mr. Tomastik is evaluating and assessing the wellbore design and geological formations for a new SWD in the Eagleford play in south Texas. Mr. Tomastik served as the expert geologic witness for Marathon Oil before the Texas Railroad Comission hearing and his testimony was critical to getting the drilling permit being issued for Marathon Oil.

For Blackbuck Resources, Mr. Tomastik testified as an expert witness before the New Mexico Oil Conservation Division at a hearing regarding a new SWD permit application and he testified on the geology and potential for induced seismicity at the proposed location.

For Tri-State Environmental, Mr. Tomastik is working with Tri-State to register as an owner/operator and, after registration, file for two new saltwater injection well permit applications. Permits have been issued.

For Vorys, Sater, Seymour, and Pease LLP, Mr. Tomastik served as an expert witness on the appeal of the authorization to inject for the Highland Field Services #5 SWIW in Brookfield, Ohio. That case has now been dismissed.

For Empire Ohio SWD, Mr. Tomastik has been evaluating potential saltwater injection well locations and geological formations for disposal in eastern Ohio. Additionally, Mr. Tomastik prepared and submitted two SWD applications for the client.

For DeepRock Disposal Solutions, LLC, Mr. Tomastik prepared and submitted a new saltwater injection well application in Washington County, Ohio. The permit was issued.

For Goodnight Midstream, Mr. Tomastik testified as an expert witness at an injection well hearing before the New Mexico Oil Conservation Division regarding well construction, injection zone, and confining zones for a proposed Class IID permit application.

For FQ Energy Services LLC, Mr. Tomastik prepared and recently submitted saltwater injection well applications for two new injection wells in Meigs County, Ohio. The permits were issued.

For FQ Energy Services LLC, Mr. Tomastik is preparing all the Class IID disposal well documents for the five-year permit renewal of FQ Energy's Ritchie Hunter #2 injection well in Ritchie County, West Virginia. The permit application has been approved.

For Omni Energy Group LLC, Mr. Tomastik has prepared all the saltwater injection well applications for two new injections wells to be permitted in Richland Township of Belmont County, Ohio and permits were issued after litigation.

For Blackbuck Resources, Mr. Tomastik has been involved with other ALL staff in the submittal of multiple saltwater disposal applications in New Mexico in the Permian Basin.

For Goodnight Midstream, Mr. Tomastik has been involved with other ALL staff in the submittal of multiple saltwater disposal applications in New Mexico in the Permian Basin.

For Southwind Oil & Gas (Marathon Oil), Mr. Tomastik was involved in the geological review, planning, permitting, drilling, completion, selecting perforations, and testing of a Class II disposal well in Lousiana. ALL served as General Contractor and finished drilling and completing the disposal well in January of 2019. The permit to inject was issued. A second SWD drilling permit has also been issued.

For EnLink Midstream, LLC, Mr. Tomastik has submitted to the Ohio Division of Oil and Gas Resources Management an application to plug back an existing Class II disposal well to a different injection zone in the Washington County, Ohio, area. The permit was issued, and the well was plugged back. Mr. Tomastik oversaw the perforating, running of tubing and packer, and acid job and injection testing on this well. EnLink has now requested Mr. Tomastik to start working on a permit to plug and abandoned the well. ALL will oversee the plugging and abandonment.

For Redbird Development, LLC, Mr. Tomastik completed all the applications and permitting of two Class II injection wells on their Redbird's property and oversaw the cementing, geophysical logging, perforating, acidizing, running the tubing and packer, and conducting the injectivity testing on the completion of the Redbird #4 injection well in Washington County, Ohio.

For EnLink Midstream, LLC, Mr. Tomastik is working with West Virginia Department of Environmental Protection (WV DEP) on an UIC application to plug back an existing Class II well in St. Marys, West Virginia, to a different zone to increase injection capacity.

For Waste Management, Mr. Tomastik has performed preliminary geological evaluation, cost estimates, and regulatory requirements to drill two Class I non-hazardous injection wells at two landfills in Ohio to dispose of landfill leachate.

For FQ Energy Services, LLC, Mr. Tomastik has completed and submitted a deep well Class II application for Noble County, Ohio, and the permit has been issued.

For Solaris Midstream, LLC, Mr. Tomastik has been involved in the permitting process for 22 Class II injection wells in the Delaware Basin in New Mexico.

For DeepRock Disposal Solutions, LLC, Mr. Tomastik oversaw the permitting of a test well and performed the open-hole logging analysis after the well reached total depth to select potential injection zones for a new Class II well in Ohio. Mr. Tomastik has completed the permit application for the conversion of this well to disposal and will be involved with the final completion.

For Highland Field Services, Mr. Tomastik is providing expertise in placement and installation of seismic monitoring units around proposed injection wells in Ohio.

For a confidential client, Mr. Tomastik is evaluating the potential of Class II wells in Ohio, West Virginia, and Pennsylvania, strategic opportunities, and feasibility of permitting a Class II well in Pennsylvania.

For Deep Rock Disposal Solutions, LLC, Mr. Tomastik has worked on approval and a groundwater protection plan for a dewatering oil and gas waste facility in West Virginia through WV DEP and West Virginia Department of Health and Human Resources (WVDHHR).

For American Water Management Services (AWMS), Mr. Tomastik testified as an expert witness on injection well injectivity and seismicity in AWMS vs. ODNR litigation case. This litigation is ongoing.

For a confidential client, Mr. Tomastik performed feasibility studies for Class I non-hazardous injection wells at landfills to inject leachate in Ohio.

For Energy Storage Ventures, Mr. Tomastik is providing regulatory and geological expertise on permit applications for a proposed natural gas liquids storage project in salt caverns in Monroe County, Ohio.

For FQ Disposal, Mr. Tomastik provided expert analysis, constructed, and gave a presentation, and met with WV DEP regarding alleged Class II injection well impacts on surrounding oil and gas production wells. He also performed a radioactive tracer survey and analysis on their West Virginia injection well and acid jobs on their injection wells in Meigs and Noble County, Ohio, and submitted a Class II disposal well application in Meigs County for inclusion of a new injection zone.

For a confidential client, Mr. Tomastik performed a geological feasibility study for Class I injection at landfills in Indiana, Texas, and Wyoming.

For Marathon Oil Company, Mr. Tomastik provided geological expertise in identification of potential injection zones (other than the Arbuckle) and evaluation of existing Class II commercial injection operations in a six-county area of western Oklahoma. The well was permitted.

For DeepRock Disposal Solutions, LLC, Mr. Tomastik has assisted with the filing of a waste facility permit application to handle heavy brine/light solids at their Class II injection facility in southeastern Ohio. He also assisted in obtaining additional regulatory approval for more storage at the Deep Rock injection facility and prepared a new application for injection well at the facility.

For the California Council on Science and Technology, Mr. Tomastik provided expertise and authored a section of the report entitled "Assessment of the Long-Term Viability of Natural Gas Storage Facilities in California."

For Select Energy Services, Mr. Tomastik provided oversight of permit application and filing of the permit application for a modification to an existing Oklahoma commercial Class II disposal well, including all communication with the Oklahoma Corporation Commission and the public notice requirement.

For Republic Services, Mr. Tomastik performed an audit of a Class I non-hazardous commercial disposal well in upper Michigan and prepared a report on the findings of the audit.

For MFC Drilling, Mr. Tomastik filed a Class II permit application for the conversion of an existing production well to saltwater disposal in Delaware County, Ohio. The permit was granted.

For Glenn O. Hawbaker Inc., Mr. Tomastik performed complete oversight of drilling and completion of a 7,400-foot Class II saltwater disposal well in Coshocton County, Ohio, including all oversight of drilling operations, cementing, waste disposal, geophysical logging, and logistical support with all subcontractors.

For James E. Arnold & Associates, LPA, Mr. Tomastik provided an expert report and testified as an expert witness in *Heinrich Production, LLC, vs. John Jack, et al*., on injection well litigation, Case No. CV16-OT-142, which was heard before the American Arbitration Association in April of 2017 in Marietta, Ohio.

For the StatesFirst (IOGCC and GWPC) workgroup, Mr. Tomastik assisted in writing and providing expertise on well construction, drilling, conversion, monitoring and observation wells, and plugging and abandonment of gas storage wells for the ongoing StatesFirst Gas Storage Primer report, which was published as a regulatory guide on gas storage for the various states.

For Seneca Resources, Mr. Tomastik has provided expertise in evaluation of Pennsylvania Department of Environmental Protection's (PA DEP's) draft induced seismic permit conditions on two Class II injection permits in Pennsylvania. Additionally, Mr. Tomastik assisted in preparation of alternate seismic monitoring plans and helped prepare a presentation on induced seismicity for PA DEP. ALL has ordered the equipment and installed a local seismic monitoring network for Seneca Resources.

For Waste Management Energy Services, Mr. Tomastik has been providing geological and regulatory expertise on the potential for Class II slurry injection operations in Ohio including various site evaluations and numerous meetings with the state regulatory agency.

For Safe Water Solutions (Kimble Companies), Mr. Tomastik designed the step-rate injection test and spinner survey for the General Clay #1 injection well and developed the AFE for the injection surface facility. Additionally, Mr. Tomastik conducted oversight of selection of subcontractors and purchase of the equipment for the surface facility. He also oversaw the surface radiological survey and installation of two monitoring wells at the surface facility.

For the Environmental Defense Fund (EDF), Mr. Tomastik has provided expertise and review of the Aliso Canyon gas storage blowout in Los Angeles, California, including an evaluation of the well construction and integrity of the gas storage wells. Additionally, Mr. Tomastik provided an assessment and comments on the California Division of Oil, Gas, and Geothermal Resources proposed draft UIC Class II rules and gas storage rules.

For a confidential client, Mr. Tomastik provided regulatory expertise as an expert witness on salt-solution mining litigation in Louisiana. The case has settled.

For a confidential client, Mr. Tomastik is providing geological expertise on induced seismicity as an expert witness in Oklahoma. This project involves multiple ligitation cases and is ongoing.

For the American Petroleum Institute (API), Mr. Tomastik developed outlines and provided initial drafts of a communication paper to API on induced seismicity related to Class II injection wells.

For Consol Energy (CNX), Mr. Tomastik conducted a site evaluation and audit of the Barnesville #1 injection well in Barnesville, Ohio, and provided Consol with recommendations and options to enhance the handling of waste fluids and increase injection rates.

For EnLink Midstream, Mr. Tomastik designed and performed oversight of two acid jobs on two Class II injection wells in Washington County, Ohio, and was successful in improving injectivity by 500 to 600 barrels per day.

For Chesapeake Energy, Mr. Tomastik designed the step-rate test and spinner survey for Chesapeake's newly drilled Class II injection well in Tuscarawas County, Ohio, and oversaw the completion of the step-rate test and spinner survey operations.

For FQ Energy Services, LLC (formerly Green Hunter Water), Mr. Tomastik provided regulatory expertise in filing a new well and brine hauling ownership registration in Ohio and West Virginia and transferring the existing injection wells over to FQ Disposal. Additionally, Mr. Tomastik provided editing and evaluation on FQ Disposal's submittal of its waste facility application to transfer the New Matamoras waste disposal facility to FQ Disposal.

For Trive Capital, a Dallas-based equity firm, Mr. Tomastik provided regulatory expertise and conducted field audits of the Green Hunter Water and Richey Hunter injection wells in Kentucky, Ohio, Oklahoma, and West Virginia for possible acquisition from bankruptcy by Trive Capital.

For OOGC Disposal Company, LLP, Mr. Tomastik has prepared and submitted all Class II injection well application documents and public notice requirement for the Black Run Disposal Well #1 in Muskingum County, Ohio, Class II saltwater disposal application.

For Viking Energy Corporation, Mr. Tomastik prepared all documents for the five-year permit renewal applications for two of Viking Energy's Class II commercial disposal wells in Kanawha

County, West Virginia, which included all geological characterization, evaluation of site security and emergency response, and groundwater protection plan.

For Evrol, LLC, Mr. Tomastik prepared all Class II saltwater injection well permit application documents, submitted the application, and oversaw publishing of public notice requirement for the Kelly #1 injection well application in Portage County, Ohio.

For Appalachian Oil Purchasers, Inc., Mr. Tomastik prepared all documents for the five-year permit renewal applications for two of their Class II commercial disposal wells in Pleasants County, West Virginia, which included a geologic characterization and groundwater protection plan.

For the City of Hudson, Mr. Tomastik has been actively engaged in the permitting process of obtaining a permit for the city to drill and complete a Class II salt-solution mining well to provide brine to the City's municipal water treatment plant and for brine to apply in the winter for snow and ice control to the City of Hudson road network. Mr. Tomastik completed a feasibility study for the city and obtained the permit for the city to drill and complete the salt-solution mining well.

For a confidential client in Ohio, Mr. Tomastik has been actively engaged in evaluating potential Class II SWD injection well siting locations, conducting geological investigations, area of review (AOR) determinations, and seismic unit installation and monitoring. This includes geophysical logging review and evaluation, AFE and bid quotations from contractors, and assistance with the permit application process and interpretation of Ohio's regulatory framework regarding Class II injection wells.

For Redbird Development, LLC in Ohio, Mr. Tomastik served as geologic consultant on the completion of a Class II injection well in southeastern Ohio. He provided oversight and geologic interpretation of the open-hole geophysical logging operation, selection of perforating depths and stimulation of the injection zones, injectivity testing of the injection zones, and oversight of the setting of the tubing and packer and mechanical integrity testing. Additionally, Mr. Tomastik provided expertise in geological evaluation of other potential, shallower injection zones for the possible development of multiple injection wells on the operator's property. Mr. Tomastik also assisted in creation of a Spill Prevention, Control and Countermeasure (SPCC) Plan and Emergency Response Plan (ERP) for this facility.

For EnLink Midstream, Mr. Tomastik served as Project Manager and General Contractor for a Class II injection well workover in West Virginia. Mr. Tomastik provided complete oversight and management of obtaining bids and quotes from multiple contractors, cost estimates and budget for EnLink Midstream for multiple phases of the well workover project, coordination and scheduling of contractors to perform the work, and management of the work being performed at the injection location. This project included drafting of a health and safety plan, holding daily job safety analysis (JSA) onsite meetings, creating daily well inspection reports, geophysical logging, installing and removing inflatable packers, removing and replacing injection tubing string and injection packer using free-standing snubbing unit operations, performing acid stimulation, and performing and demonstrating mechanical integrity testing and putting the injection well back into operation. Additionally, Mr. Tomastik has provided geological assessments and AOR determinations and has completed a drilling and completion AFE for EnLink Midstream on multiple potential injection well siting locations. Mr. Tomastik has also conducted file reviews of existing EnLink Class II wells to provide expertise in evaluation of well performance and treatment.

For a confidential client in Ohio, Mr. Tomastik was directly involved in oversight and writing of an Expert Report to address a case of induced seismicity involving a Class II operation in Ohio, which includes geological investigation, injection pressure and volume evaluation, and recommendations to assist the client with the regulatory agency to get the injection well back into operation.

For the Florida Department of Environmental Protection, Mr. Tomastik assisted in creation of an Expert Report for the investigation of alleged environmental impacts resulting from the drilling and completion of a deep, unconventional horizontal well in Collier County, Florida. This report included geologic and hydrogeologic investigation, well construction and cementing practices evaluation, review and analysis of the well stimulation records, and evaluation of plugged oil and gas wells in the immediate vicinity to investigate the potential avenues for migration of stimulation fluids.

For several confidential clients, Mr. Tomastik has been involved in conducting siting investigations, AOR determinations, and possible land acquisitions for proposed Class II well locations in Ohio.

For the Ohio EPA, Mr. Tomastik prepared an Expert Report on the Class I applications submitted by Husky Refining and assisted Ohio EPA in addressing concerns from the ODNR.

For the ODNR DOGRM, Mr. Tom Tomastik served as senior lead geologist and UIC expert for the DOGRM for 25-1/2 years overseeing the permitting activity of all Class II and Class III injection well applications and permit issuance. This included performing independent reviews of the engineering-designed drilling programs and surface facilities; creating proposed drilling, casing, cementing, and stimulation plans; conducting hundreds of area of review evaluations to determine the feasibility of injection without corrective action; determining deepest underground sources of drinking water (USDWs); and issuing hundreds of Class II and Class III injection well permits. Mr. Tomastik oversaw all Class II and Class III compliance and enforcement actions, including management of the UIC database and review of all UIC well inspection reports. For the last eight years of his career at DOGRM, Mr. Tomastik prepared all UIC federal grant applications and oversaw grant management and for the last 14 years directly oversaw submittal of all bi-annual 7520 reports to U.S. EPA. Mr. Tomastik served on numerous occasions as DOGRM's technical expert and witness on injection wells and groundwater investigations before the Ohio Oil and Gas Commission and the Ohio Reclamation Commission and in a number of civil cases before various Ohio county court systems. Mr. Tomastik also was the technical expert for DOGRM and reviewed Class I hazardous and non-hazardous applications and permits-to-operate and Class V applications and prepared comments and made recommendations regarding these applications to Ohio EPA. Additionally, Mr. Tomastik served as a State Member of the U.S. EPA UIC National Technical Workgroup for six years.

For ODNR, Division of Mineral Resources Management (DMRM), Mr. Tomastik conducted hundreds of groundwater investigations of alleged impacts from oil and natural gas industry, coal mining, and industrial minerals mining operations in Ohio. Mr. Tomastik was the project leader and participated in major groundwater dewatering investigations of mining operations near Toledo, Ohio, and on Kelleys Island, Ohio, and successfully got water supply replacement to almost 50 private residences. Additionally, Mr. Tomastik assisted and was successful in closing the "Bainbridge Incident," where almost 30 private water wells were impacted by stray gas invasion from an overpressurized annulus on a conventional oil and natural gas well in northeastern Ohio. Mr. Tomastik was instrumental with DMRM in acquiring highly technical equipment such as color downhole video cameras and pressure transductors, which enhanced DMRM's ability to quickly resolve groundwater investigation cases with mining and oil and gas industry operators.

As a private consulting geologist, Mr. Tomastik oversaw the drilling and completion of 26 conventional oil and natural gas wells in Ohio and the drilling or conversion of six Class II saltwater injection wells. This work included detailed geologic mapping, cross sections, and report writing, oversight of drilling, cementing, geophysical logging, perforating, hydraulic fracturing, and acid treatment of these wells. Mr. Tomastik also participated in plumbing up wellheads, putting in pipelines, pumping, and plugging oil and natural gas wells in Ohio.

Professional Organizations

American Association of Petroleum Geologists, Certified Petroleum Geologist #6354

National Ground Water Association

Ohio Geological Society

Ground Water Protection Council

Publications and Presentations

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Whittenmore, D.O., D.A. Hodges, and T.E. Tomastik. 1991. "Finger Printing and Quantifying Salinity Sources in Multicomponent Mixtures." 36th Annual Midwest Groundwater Conference, October 9-11, 1991, Indianapolis, Indiana.

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Tomastik, T.E. 2002. "Salt Deposits in Ohio – Geology, Mining, and Uses." In *2001 Report on Ohio Mineral Industries.* Compiled by M.E. Wolfe, M.E., Ohio Division of Geological Survey, p. 1-7.

Van Oort, M.D., E.S. Bair, and T.E. Tomastik, T.E. 2003. "Numerical Modeling of the Effects of a Quarry Dewatering Operation in Northwest Ohio." Geological Society of America, 2003 Seattle Annual Meeting, November 2-5, 2003, abstract.

Tomastik, T.E., and others. 2004. "Water Rights Dispute – The Effects of a Quarry Dewatering Operation in Northwest Ohio." 2004 National Ground Water Association Ground Water and Environmental Law Conference, May 5-6, 2004, Chicago, Illinois.

Tomastik, T.E., D.A. Hodges, and C.L. Scheerens. 2004. "Oilfield Complaints in Ohio: Procedures and Guidelines for Conducting Alleged Water Well Contamination Investigations." 2004 Ground Water Protection Council Annual Forum, September 18-22, 2004, Charleston, South Carolina, abstract.

Tomastik, T.E., and others. 2004. "Aggregate Mining in Ohio – The Effects of a Quarry Dewatering Operation in Northwest Ohio." 2004 American Association of Petroleum Geologists Eastern Section Meeting, October 3-6, 2004, Columbus, Ohio, abstract.

Tomastik, T.E. 2005. "Overview of State Issues with National Technical Workgroup Products: AOR/ZEI and Annular Disposal of Drilling Wastes." Ground Water Protection Council 2005 Annual Forum, September 24-29, 2005, Portland, Oregon, abstract.

Tomastik, T.E. 2006. "Water Well Complaint Investigations: What We Have Learned and What We Can Recommend." Ohio Environmental Health Association, 2006 Northwest Ohio Environmental Health Association Annual Autumn Education Conference, October 19-20, 2006, Sandusky, Ohio.

Tomastik, T.E., and T. Benko. 2007. "Groundwater Investigation of Potential Dewatering and Depressurization Impacts on Kelleys Island, Erie County, Ohio." 2007 National Ground Water Association Ground Water and Environmental Law Conference, July 24-25, 2007, Columbus, Ohio, Paper #4187.

Tomastik, T.E. 2009. "Site Characterization for CO2 Geosequestration." 2009 Ground Water Protection Council UIC and Deep Well Conference, January 25-27, 2009, San Antonio, Texas, abstract.

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Tomastik, T.E., and E.S. Bair. 2010. "The 'Bainbridge Natural Gas Incident' in Geauga County, Ohio: What Really Happened!" 2010 Ground Water Protection Council Annual Forum, September 26-29, 2010, Pittsburgh, Pennsylvania, abstract 16.

Tomastik, T.E. 2010. "Oilfield Complaints in Ohio: Procedures for Conducting Alleged Water Well Contamination Cases." 55th Annual Midwest Groundwater Conference, October 4-7, 2010, Columbus, Ohio, abstract.

Tomastik, T.E. 2011. "Ohio's Regulations on Natural Gas Development and Disposal of Oilfield Wastes." Annual Midwest Workshop in Environmental Health, March 21-24, 2011, Columbus, Ohio.

Tomastik, T.E. 2011. "State Investigations of Oilfield Ground Water Incidents and Their Role in Advancing Regulatory Reforms." National Ground Water Association/Ground Water Protection Council Ground Water Summit, May 5, 2011, Baltimore, Maryland.

Tomastik, T.E. 2011. "Hydraulic Fracturing and Water Resources in Ohio: How to Protect the Groundwater through Proper Well Construction and Cementing Practices." 2011 Ground Water Protection Council Annual Forum, September 24-28, 2011, Atlanta, Georgia.

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Tomastik, T.E. 2012. "Risks, Benefits, Myths, and Realities of Hydraulic Fracturing." American Academy of Environmental Engineers and Scientists, U.S. Clean Energy Challenges Focus on Hydraulic Fracturing 2012 Webinar, September 27, 2012.

Tomastik, T.E. 2013. "Preliminary Report on the Northstar #1 Class II Injection Well and Seismic Events in the Youngstown, Ohio Area." Ground Water Protection Council 2013 Underground Injection Control Conference, Aquifer Management & Underground Injection, Sarasota, Florida, January 22-24, 2013, abstract 23.

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Tomastik, T.E. 2013. "Conducting a Stray Gas Investigation and the Use of Downhole Videography as an Investigation Tool." Ground Water Protection Council 2013 Stray Gas Incidence & Response Forum, Grapevine, Texas, July 9-11, 2013, abstract 7.

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Arthur, J.D., T.E. Tomastik, D. Overstreet, and B.G. Casey. 2015. "Class II Disposal Well Best Management Practices Workshop." Ground Water Protection Council – Interstate Oil and Gas Compact Commission 2015 Annual Meeting, Oklahoma City, Oklahoma, September 27-30, 2015, abstract.

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Arthur, J.D., T.E. Tomastik, and D. Cornue. 2016. "Understanding Key Aspects of Well Integrity: A Workshop." Ground Water Protection Council 2016 Annual Forum, Orlando, Florida, September 11-14, 2016.

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Tomastik, T. 2019. "Large Potential Reserves Remain for Secondary Oil Recovery in Ohio". 2019 American Association of Petroleum Geologists Eastern Section Meeting, October 12-16, 2019, Worthington, Ohio.

Tomastik, T. 2020. "Potential for Underground Storage of Natural Gas Liquids in Salt-Solution Mined Caverns in the Appalachian Area." Ohio Geological Society, February 20, 2020, Columbus, Ohio.

Tomastik, T. 2021. "The Future of Carbon, Capture, Utilization, and Storage (CCUS): Insight and Opportunities for Geoscientists." Ohio University Geological Sciences 2021 Alumni Symposium, Athens, Ohio, April 16-17, 2021.

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Tomastik, T. and J. D. Arthur 2022. "Elimination of PFAS at Landfills Via Class I Injection." Ground Water Protection Council 2022 Annual Meeting, Slat Lake City, Utah, June 21-24, 2022.

Tomastik, T. et al. 2022. "Addressing the Challenges of CCUS and Pursuing a Plan to Success." Ground Water Protection Council 2022 Annual Meeting, Slat Lake City, Utah, June 21-24, 2022.

Tomastik, T. 2023. "Plugging of Orphan Oil and Gas Wells – Insights, Opportunities, and the Challenges they Present." Ohio Geological Society Meeting, May 19, 2023, Columbus, Ohio.

Short Courses and Continuing Education

Water Well Rehabilitation Workshop, Bowser-Morner

Underground Injection Class III and Storage Cavern Well Operator Training, Subsurface Technology

Analysis and Design of Aquifer Tests including Slug Tests and Fracture Flow, National Ground Water Association

Exploration and Evaluation of Fractured Reservoirs, Petroleum Technology Transfer Council

Class I Operator Training, Ground Water Protection Council

Principals of Ground Water, National Ground Water Association

Environmental Forensics: Methods and Applications, National Ground Water Association

Introduction to Well and Wellfield Performance Maintenance and Improvement, Ground Water Science

Water Well Rehabilitation: Water Well Problems/Effective Solutions, In-situ Water Treatment, Subsurface Technologies, Inc.

Tom Tomastik

Improving Hydrogeologic Analysis of Fractured Bedrock Systems, Midwest Geosciences

Injection Well Operator Training, Subsurface Technology and Ground Water Protection Council

U.S. EPA Hydraulic Fracturing Technical Workshop on Well Construction/Operations and Subsurface Modeling, U.S. EPA

Safelands Training

Fundamentals of Seismic Interpretation, Ohio Geological Society

Bond Log Interpretation – Basics and Beyond

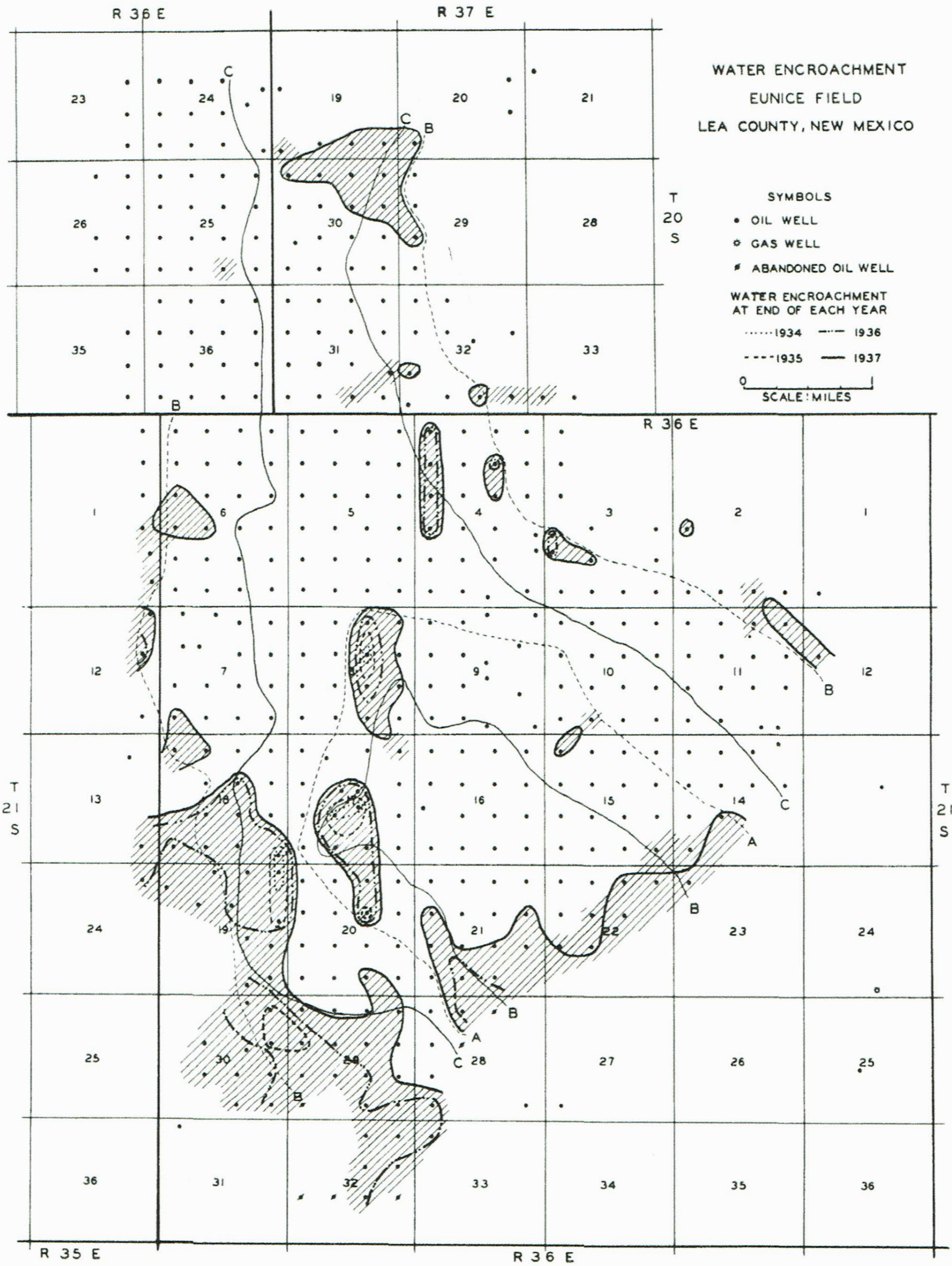
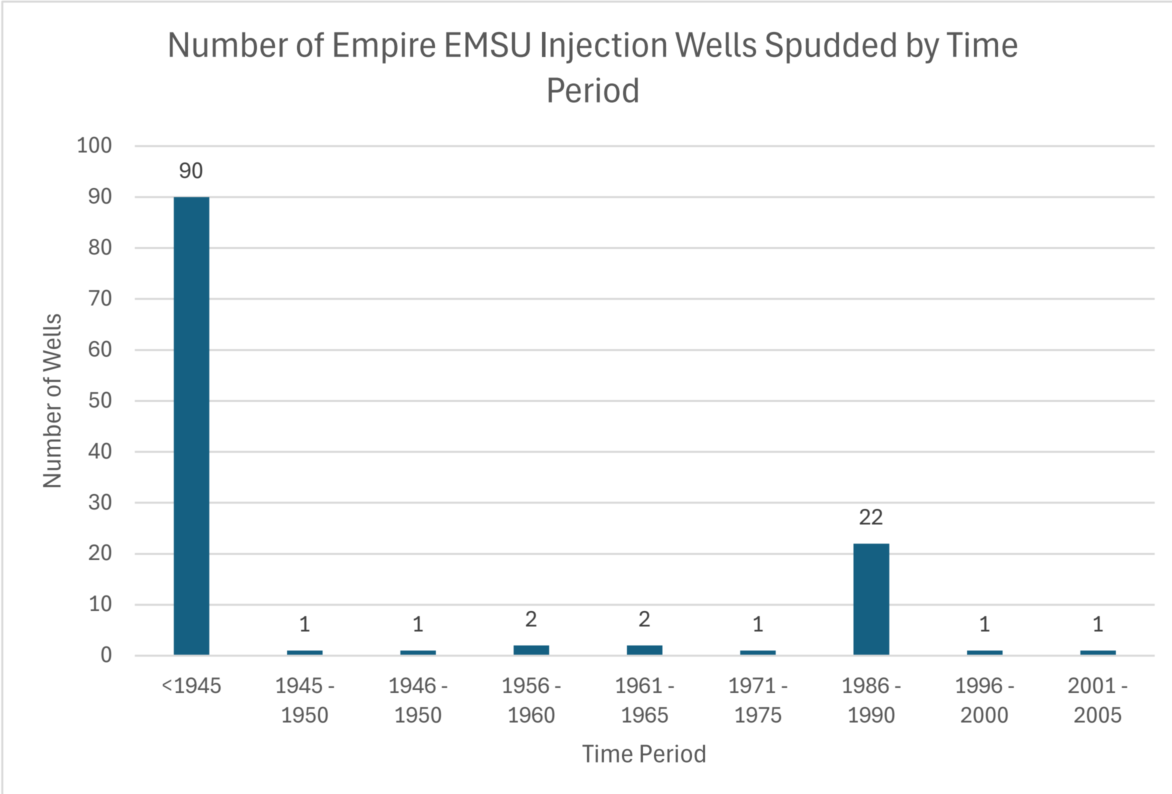
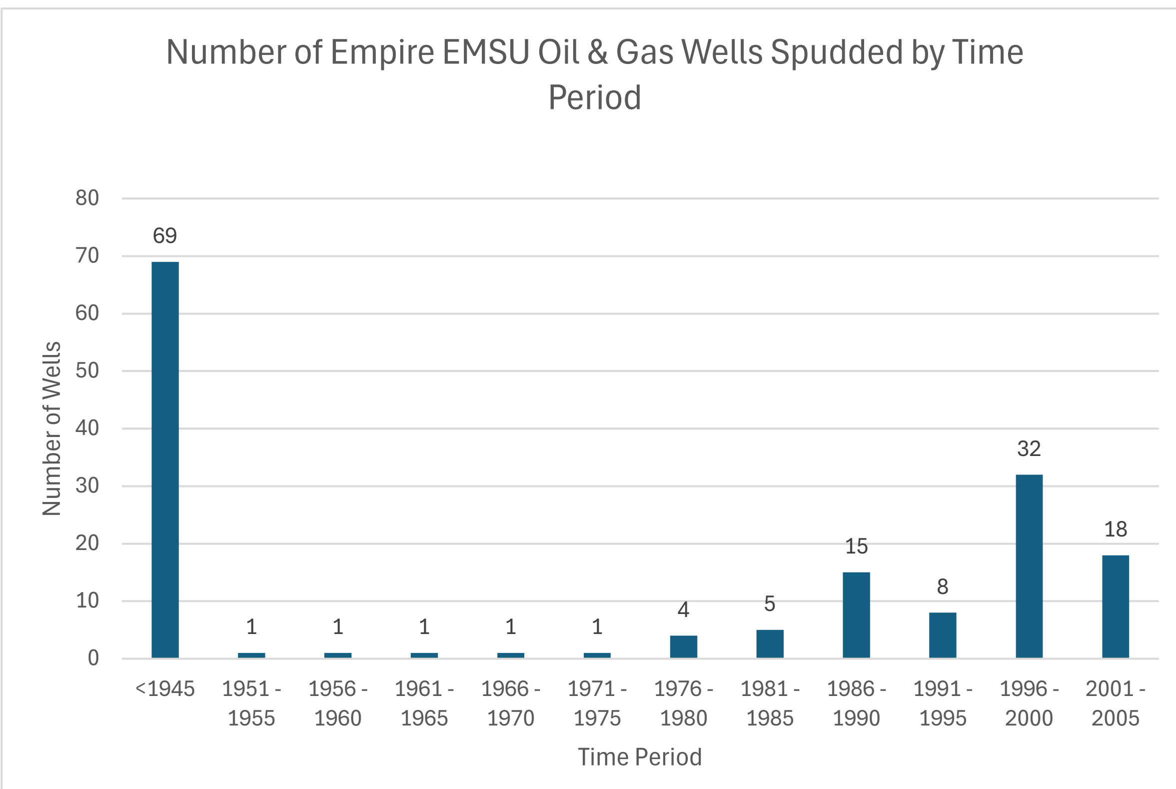


Figure 10.

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-2
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123





BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-3
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-4
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

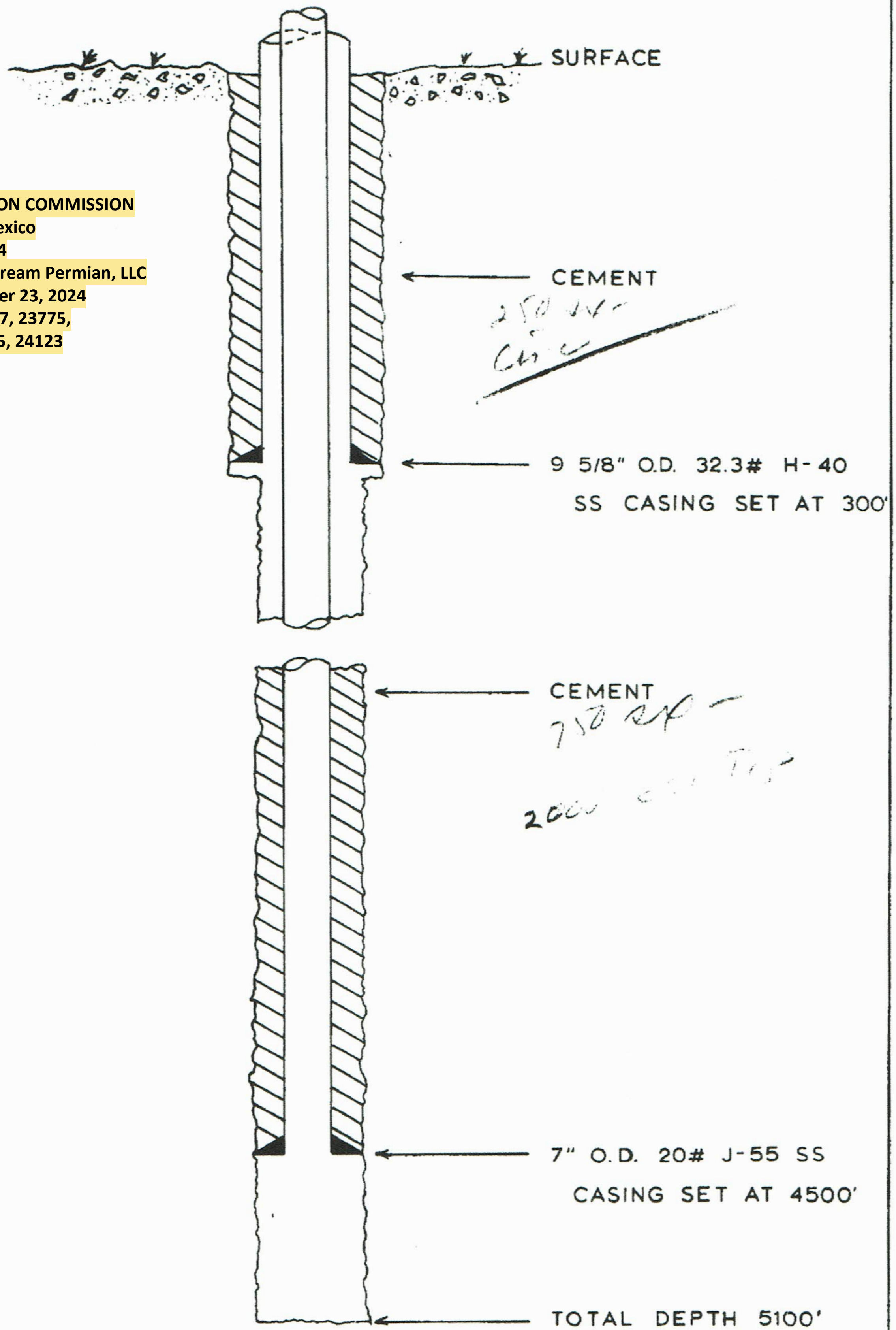


EXHIBIT "B"

DWN	AMM	6-66	PROPOSED COMPLETION EME SWD WELL L-21	SCALE NONE
			Rice Engineering & Operating, Inc. Hobbs, New Mexico	DWG NO.

FORMATION WATER ANALYSIS

MILLIGRAMS PER LITER

	GRAYBURG
Sodium, Na	5,060
Calcium, Ca	665
Magnesium, Mg	295
Sulphate, SO_4	120
Chloride, Cl	9,620
Bicarbonate, HCO_3	1,910
Hydrogen Sulphide, H_2S	180
TOTAL SOLIDS	17,850
pH	7.6
Specific Gravity	1.009

Chevron

Chevron U.S.A. Inc.
P. O. Box 670, Hobbs, NM 88240

R. C. Anderson
Division Manager
Hobbs Division
Production Department

Hobbs, New Mexico
January 16, 1986

APPLICATION FOR SALT WATER DISPOSAL, MEYER B-4 WELL NO. 23 (FUTURE EMSU SWD WELL NO.1), EUNICE MONUMENT SOUTH UNIT, LEA COUNTY, NEW MEXICO

W. J. Lemay
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Gentlemen:

Chevron U.S.A Inc. respectfully requests administrative approval to dispose of salt water down the subject well into a porous formation not productive of hydrocarbons in this area. Produced salt water from the Eunice Monument Grayburg and Lower Penrose formations will be disposed of in the San Andres formation which occurs in this wellbore from approximately 4150 feet to 5280 feet and is in the EMSU's unitized interval. Disposal will be through internally plastic coated tubing beneath a packer set at approximately 4400 feet.

The following information is submitted in support of this request:

1. Oil Conservation Division Form C108 with supporting data;

2. Affidavit of publication in newspaper with county-wide circulation;

3. Location plat outlining the subject well's ½ mile radius of review;

4. Log of the subject well;

5. Listing of names and addresses of the offset operators.

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-5
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

Example of fluid flow from carbonate rocks - limestones and dolomites

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-6
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-7
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

Tax Incentive: Project Description

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-8
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

Capital cost of additional facilities: *$246 million*

Total Project Capital Costs: *$312 million*

Estimated total value of the additional production that will be recovered as a result of this tertiary recovery project:

> *An additional 33.25 mmbls of oil at a gross revenue estimated at $2.8 billion over the life of the project (approximately 40 years)*

Anticipated date of commencement of injection: *September 2015*

The type of fluid to be injected and the anticipated volumes:

> *Maximum water injection rate of 115,000 BWPD;*
> *Maximum CO2 injection rate of 45 MMCFD; and*
> *Maximum rejection of CO2 and produced gases of 75 MMCFD*

Tax Incentive: Project Description

Capital cost of additional facilities: *$280 million*

Total Project Capital Costs: *$425 million*

Estimated total value of the additional production that will be recovered as a result of this tertiary recovery project:

> *An additional 54 mmbls of oil at a gross revenue estimated at $4.5 billion over the life of the project (approximately 40 years)*

Anticipated date of commencement of injection: *First Quarter 2016*

The type of fluid to be injected and the anticipated volumes:

> *Water injection rate of 300,000 BWPD;*
> *CO_2 injection rate of 100 MMCFD; and*
> *Rejection of CO_2 and produced gases of 150 MMCFD*

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-9
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

OXY

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

APPLICATION OF OCCIDENTAL PERMIAN LTD TO AMEND ORDER NO. R-6199-B TO EXPAND THE NORTH HOBBS GRAYBURG-SAN ANDRES UNIT PHASE I TERTIARY RECOVERY PROJECT, TO MODIFY CERTAIN OPERATING REQUIREMENTS, AND TO CERTIFY THIS EXPANSION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE NEW MEXICO ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO.

CASE NO. 15103
ORDER NO. R-6199-F

ORDER OF THE COMMISSION

This case comes before the New Mexico Oil Conservation Commission ("Commission") on the application of Occidental Permian Ltd. ("Oxy") to amend Order No. R-6199-B, as amended. The Commission, having conducted a hearing on March 13, 2014, at Santa Fe, New Mexico, and having considered the testimony and the record in the case, enters the following findings, conclusions and order:

THE COMMISSISION FINDS THAT:

1. Due public notice has been given, and the Commission has jurisdiction of this case and its subject matter.

2. On October 3, 1979, the Commission entered Orders No. R-6198 and R-6199 in Case Nos. 6652 and 6653 that statutorily unitized the North Hobbs Unit and approved a pressure maintenance project by the injection of water into the Grayburg and San Andres formations underlying the following acreage in Lea County, New Mexico:

TOWNSHIP 18 SOUTH, RANGE 37 EAST, NMPM

Section 13:	W/2, SE/4
Section 14:	All
Section 23:	All
Section 24:	All
Section 25:	All
Section 26:	E/2 NE/4, NW/4 NE/4
Section 36:	E/2, E/2 NW/4

TOWNSHIP 18 SOUTH, RANGE 38 EAST, NMPM

Section 17:	S/2 NW/4, SW/4

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-11
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775, 24018 – 24020, 24025, 24123

Section 18:	NE/4 and S/2
Section 19:	All
Section 20:	All
Section 21:	SW/4, W/2 SE/4, SE/4 SE/4
Section 27:	All
Section 28:	All
Section 29:	All
Section 30:	All
Section 31:	All
Section 32:	All
Section 33:	W/2, NE/4, W/2 SE/4, and NE/4 SE/4
Section 34:	E/2, E/2 NW/4

3. On October 22, 2011, the Energy, Minerals and Natural Resources Department Oil Conservation Division ("Division") entered Order No. R-6199-B authorizing a carbon dioxide gas tertiary recovery project within a portion of the North Hobbs Unit called the "Phase I Area" by injection of carbon dioxide (CO2), produced water, and produced gas through certain existing wells and yet to be drilled wells in the quarter-quarter sections identified on Exhibits A and B to that Order.

4. Since the entry of Order No. R-6199-B, the Division has approved additional injection wells in the Phase I area of the North Hobbs Unit through various administrative and hearing orders.

5. Oxy is the current operator of the North Hobbs Unit and now seeks the following relief from the Commission as provided in an Application filed with the Commission on February 11, 2014 ("Application"):

(a) to expand the approved geographic area for the carbon dioxide gas tertiary recovery injection project to include the following acreage:

<u>TOWNSHIP 18 SOUTH, RANGE 37 EAST, NMPM</u>

Section 13:	W/2, SE/4
Section 14:	All
Section 23:	All
Section 24:	All
Section 25:	All
Section 26:	E/2 NE/4, NW/4 NE/4
Section 36:	E/2, E/2 NW/4

<u>TOWNSHIP 18 SOUTH, RANGE 38 EAST, NMPM</u>

Section 17:	S/2 NW/4, SW/4
Section 18:	NE/4 and S/2
Section 19:	All
Section 20:	All
Section 21:	SW/4, W/2 SE/4, SE/4 SE/4
Section 28:	All

Section 29:	All
Section 30:	All
Section 31:	All
Section 32:	All
Section 33:	W/2, NE/4, W/2 SE/4, and NE/4 SE/4

(b) to expand the injection authority to include new wells in the quarter-quarter sections identified on Exhibit A to the Application and the existing producing or temporarily abandoned wells identified on Exhibit B to the Application;

(c) to confirm that the well limitation for quarter-quarter sections set forth in NMAC 19.15.15.9(A) does not apply to active tertiary recovery projects, such as the North Hobbs Unit project;

(d) to grant an exception to NMAC 19.15.15.13(A) (unorthodox well locations) to allow wells to be closer than 10 feet to a quarter-quarter section line or subdivision inner boundary within the North Hobbs Unit area;

(e) to grant an exception to the notice requirements set forth in NMAC 19.15.26.8.C and 19.15.26.8.F to allow for administrative approval of additional injection wells in the expanded North Hobbs Unit area without notice and hearing;

(f) to provide that for any injection well covered by this application that does not commence injection within 5 years after approval of this request, Oxy may submit within a period no more than twelve months and no less than sixty days before injection operations commence in the well either (i) a statement certifying that there have been no substantive changes to the information furnished in support of this application concerning the status or construction of any well that penetrates the injection interval within the one half (1/2) mile area of review around the injection well; or (ii) a statement describing any substantive changes;

(g) to eliminate the existing limiting gas-oil ratio of 6,000 cubic feet of gas per barrel of oil and to provide that no limiting gas-oil ratio or oil allowable applies to this expanded enhanced oil recovery project;

(h) to modify the packer setting depth required by R-6199-B Ordering Paragraph (3) to allow for the packer to be set anywhere above the uppermost injection perforations or casing shoe, provided the packer is set below the top of the Grayburg Formation;

(i) to provide a five-year frequency for mechanical integrity tests for temporarily abandoned wells equipped with real-time pressure monitoring devices pursuant to NMAC 19.15.25.13.E; and

(j) to certify the approved expansion of the tertiary recovery project for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, Sections 7-29A-1 to 7-29A-5 NMSA 1978 (Laws 1992, Chapter 38, Section 1 through 5) ("Recovery Act") and the rules of the Commission, 19.15.6 NMAC ("Rules").

6. At the hearing, upon the request of Oxy, the Commission adopted and took notice of the record from Case No. 14981, which resulted in Order No. R-4934-F approving a tertiary recovery project in the adjacent South Hobbs Project Area. The Commission also noted that several persons had filed written notices of appearance in this proceeding including Cornelia England, Gerald Carl Golden, Sharon Aileen Mehs (Lee) and Thomas R. Mehs.

7. Oxy presented five witnesses in support of its Application: Jerad Brockman, Oxy's project manager with expertise in oil and gas production engineering; Randy Stillwell, a senior geologic advisor for Oxy with expertise in petroleum geology; Scott Hodges, Oxy's operations supervisor; Kelley Montgomery, Oxy's regulatory consultant with expertise in oil and gas production engineering; and Pat Sparks, Oxy's petroleum landman with expertise in petroleum land matters. Oxy's witnesses provided testimony and presented exhibits addressing the following topics:

(a) Oxy's current operations and facilities within the Phase I area of the North Hobbs Unit and the planned expansion of gas injection operations;

(b) The injection and production well patterns in the expanded Phase I Area, the need to exceed four wells per forty acre spacing unit, and the potential need to locate wells closer than ten feet to the quarter-quarter section lines;

(c) The capital costs and projected timeline for installation of key components of the expansion of gas injection in the Phase I area;

(d) The production history of the North Hobbs Unit and the additional oil anticipated from the Phase I area expansion project;

(e) The need for additional flexibility in the packer setting depth than what is currently allowed by Order No. R-6199-B;

(f) The geology underlying the North Hobbs Unit, the location of the fresh water zones and the impermeable barriers that exist between the injection interval and the fresh water zones;

(g) The gas injection facilities and pressure control devices Oxy utilizes in the Phase I area;

(h) The supervisory control and data acquisition (SCADA) system Oxy utilizes to provide real time monitoring of pressures, temperature, water content, H2S levels and gas content in the North Hobbs Unit;

(i) How Oxy monitors for H2S releases in the existing and proposed expanded Phase I area;

(j) Oxy's mechanical integrity program for the design, engineering, construction and maintenance of CO2 and produced gas injection facilities for enhanced oil recovery projects like the North Hobbs Unit;

(k) The NACE Standard MRO175 set forth in NMAC 19.15.11.14 and Oxy's compliance with that standard for the injection facilities in the existing and proposed expanded Phase I Area;

(l) The additional corrosion inhibition and mitigation efforts Oxy will utilize for the installation, construction and maintenance of the injection facilities in the proposed expanded Phase I Area;

(m) Oxy's downhole corrosion mitigation efforts, including the use of corrosion resistant tubing, packers and inert packer fluid in the annulus of wells in the existing and proposed expanded Phase I Area;

(n) The time frame for mechanical integrity tests for temporarily-abandoned wells under NMAC 19.15.25.12 and the absence of a need for more frequent testing for wells equipped with real-time pressure monitoring devices;

(o) The location of existing gas injection wells in the Phase I Area and the proposed locations for the expansion efforts;

(p) The condition of the existing injection wells and design plans for additional injection wells in the Phase I Area;

(q) Oxy's plans to add additional cement behind the production casing across the fresh water zone in the North Hobbs Unit Well No. 231 (API No. 30-025-07545) in the SE/4 NW/4 (Unit F) of Section 33 of Township 18 South, Range 38 East, prior to using this well for gas injection;

(r) The area of review analysis conducted by Oxy and the conditions of the wells within the area of review;

(s) The extensive knowledge of the wells within the area of review, the amount of time and effort devoted to the area of review analysis, and the absence of a need to update the area of review analysis for any injection wells that commence injection over the next five years;

(t) The methodology, time frame and effort involved to ascertain the parties entitled to notice of the hearing on Oxy's application; and

(u) The parties notified of the hearing either by certified mail or by newspaper publication.

8. The Division's Environmental Bureau has approved a hydrogen sulfide contingency plan that covers the North Hobbs Unit Area.

9. The geologic evidence establishes the following with respect to the Grayburg and San Andres formations underlying the North Hobbs Unit :

(a) These formations consist of a layered, anticlinal structure that acts as a natural trapping mechanism for oil, as well as any injected fluids.

(b) These formations are separated from the fresh water zones by over 3,500 feet.

(c) The upper portion of the Grayburg formation consists of 150 to 200 feet of impermeable anhydrite and limestone.

(d) Various additional layers of impermeable anhydrite, salt, shale and limestone exist between these injection formations and the fresh water zones.

(e) No geologic faults or other natural means exist in this area by which injected fluids could communicate with the shallower fresh water zones.

10. With respect to the existing wells and the proposed injection wells within the area of review for the expanded Phase I Area of the North Hobbs Unit, the evidence establishes that:

(a) The existing injection wells in the expanded Phase I Area of the North Hobbs Unit are sufficiently cased and cemented to prevent the migration of injection fluids out of the proposed injection interval. Nonetheless, Oxy intends to add additional cement behind the production casing across the fresh water zone for the North Hobbs Unit Well No. 231 (API No. 30-025-07545) in the SE/4 NW/4 (Unit F) of Section 33 of Township 18 South, Range 38 East, prior to using this well for gas injection.

(b) Oxy's design for additional injection wells in the expanded Phase I Area of the North Hobbs Unit will provide sufficient casing and cement to prevent the migration of injection fluids out of the proposed injection interval.

11. The evidence demonstrates it is prudent to expand the geographic area for the tertiary recovery operations in the Grayburg and San Andres formations underlying the North Hobbs Unit as proposed by Oxy and that expansion of the Phase I Area of the North Hobbs Unit will result in the recovery of additional oil that may otherwise not be recovered and wasted.

12. The evidence presented to the Commission demonstrates that Oxy's proposed expansion of the tertiary recovery operations in the Grayburg and San Andres formations underlying the North Hobbs Unit will not pose an unreasonable threat to groundwater, the public health or the environment.

13. Oxy's request to expand the geographic area for the injection of CO2, water, and produced gases in the North Hobbs Unit should be approved.

14. The well limitation for quarter-quarter sections set forth in NMAC 19.15.15.9(A) does not apply to active tertiary recovery projects and Oxy should be allowed to locate wells closer than 10 feet to a quarter-quarter section line or subdivision inner boundary within the North Hobbs Unit.

15. Based on the extensive area of review analysis performed by Oxy, and the previous reviews conducted by Oxy and the Division in connection with previous applications to expand the injection authority in the Phase I Area of the North Hobbs Unit, the Commission finds it is unnecessary to update the existing area of review analysis for a period of five years. However, if any well commences injection operations more than five years after the date of this order, Oxy should submit a statement to the Division that there have been no substantive changes to the area-of-review information submitted, or a statement describing any substantive changes.

16. Pursuant to NMAC 19.15.25.13.E, and based on the evidence presented on Oxy's SCADA system and proposed real time pressure monitoring devices, the Commission finds it is appropriate to conduct mechanical integrity tests on temporarily-abandoned wells equipped with real-time pressure monitoring devices once every five years.

17. The geologic and other evidence presented demonstrates Oxy should be allowed to set packers in injection wells in the North Hobbs Unit anywhere above the uppermost injection perforations or casing shoes, so long as the packer is set below the top of the Grayburg formation.

18. With respect to Oxy's request that its proposed expanded injection authority qualify for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, the evidence establishes that:

(a) Oxy's planned enhanced oil recovery project in the expanded Phase I Area of the North Hobbs Unit should result in the recovery of an additional 54 million barrels of oil that may otherwise not be recovered, thereby preventing waste.

(b) The proposed expanded Phase I Area of the North Hobbs Unit has been depleted to the point that it is prudent to apply enhanced recovery techniques to maximize the ultimate recovery of crude oil;

(c) The application is economically and technically reasonable and has not been prematurely filed; and

(d) The proposed tertiary recovery project meets all of the criteria for certification as a qualified "enhanced oil recovery project" under the Recovery Act and the Rules. NMSA 1978, Section 7-29A-4; NMAC 19.15.6.8.E.

19. The proposed tertiary recovery project in the expanded Phase I Area of the North Hobbs Unit will prevent waste, protect correlative rights, and should be approved with certain conditions.

THE COMMISSION CONCLUDES THAT:

1. The Commission is empowered to regulate and permit the injection of natural gas or of any other substance into any pool in this state for the purpose of repressuring, cycling, pressure maintenance, secondary or any other enhanced recovery operations. NMSA 1978, Section 70-2-12(B)(14). The Commission has a further statutory duty to prevent waste and protect correlative rights. NMSA 1978, Section 70-2-11(A).

2. Oxy has provided substantial evidence to support the approval of the authority to inject CO2, and produced water and produced gases into the North Hobbs Project Area subject to the conditions provided in this Order, which conditions are necessary to prevent waste and protect correlative rights and public health and the environment.

3. The Commission and the Division have the authority to certify "enhanced recovery projects" that are eligible for a "recovered oil tax rate" under the Enhanced Oil Recovery Act, NMSA 1978, Sections 7-29A-1 to -5 (1992) and under the Rules, 19.15.6 NMAC. The North Hobbs Grayburg-San Andres Unit Pressure Maintenance Project, as described by this Order, meets the requirements for certification as an enhanced recovery project and a tertiary recovery project under the Recovery Act and the Rules. The North

Hobbs Project Area shall be designated as the area to be affected by the enhanced recovery project.

IT IS THEREFORE ORDERED THAT:

(1) The provisions of this Order shall govern the tertiary recovery project described herein. The provisions of Orders No. R-6199-B, R-6199-C, R-6199-D and R-6199-E remain applicable to the ongoing operations in the North Hobbs Unit, except to the extent that they are inconsistent with this Order.

(2) Oxy is authorized to expand the geographic area of the current tertiary recovery project in the Phase I Area of the North Hobbs Unit by the injection of CO2, water, and produced gases into the Grayburg and San Andres formations underlying the following acreage:

TOWNSHIP 18 SOUTH, RANGE 37 EAST, NMPM

Section 13:	W/2, SE/4
Section 14:	All
Section 23:	All
Section 24:	All
Section 25:	All
Section 26:	E/2NE/4, NW/4 NE/4
Section 36:	E/2, E/2 NW/4

TOWNSHIP 18 SOUTH, RANGE 38 EAST, NMPM

Section 17:	S/2 NW/4, SW/4
Section 18:	NE/4 and S/2
Section 19:	All
Section 20:	All
Section 21:	SW/4, W/2 SE/4, SE/4 SE/4
Section 28:	All
Section 29:	All
Section 30:	All
Section 31:	All
Section 32:	All
Section 33:	W/2, NE/4, W/2 SE/4, and NE/4 SE/4

(3) The injection of CO2, water and produced gases is authorized for the wells and locations identified on Exhibits "A" and "B" attached to this Order. Application for approval of additional injection wells in the expanded Phase I Area of the North Hobbs Unit shall be filed in accordance with NMAC 19.15.26.8 and may be approved administratively by the Division Director without notice and hearing.

(4) For any injection well or location identified on Exhibits "A" or "B" to this Order in which tertiary injection operations commence more than five years after the date of this Order, the operator shall submit to the Division either: (i) a statement certifying that there have been no substantive changes in the information furnished in support of the

subject application concerning the status or construction of any well that penetrates the injection interval within the one half (1/2) mile area of review around the injection well; or (ii) a statement describing any substantive changes. This statement shall be submitted to the Division's Santa Fe office within a period no more than twelve months and no less than sixty days before injection operations commence in the well.

(5) The well limitation for quarter-quarter sections set forth in NMAC 19.15.15.9(A) does not apply to active tertiary recovery projects and Oxy is authorized to locate wells closer than 10 feet to a quarter-quarter section line or subdivision inner boundary within the North Hobbs Unit.

(6) No limiting gas oil ratio or oil allowable applies to this enhanced oil recovery project.

(7) The injection wells or pressurization system within the expanded Phase I Area of the North Hobbs Unit shall be equipped with a pressure control device or acceptable substitute that will limit the surface injection pressure to no more than:

1100 psig for injection of water;
1250 psig for injection of CO_2; and
1770 psig for injection of produced gases.

(8) The Division Director may administratively authorize an increase in surface injection pressure upon a showing by the operator that such higher pressure will not result in the fracturing of the injection formation or confining strata.

(9) The operator shall take all necessary steps to ensure that the injected gases and fluids enter only the Grayburg and/or San Andres formations and are not permitted to escape to other formations or to the surface from injection, production, or plugged and abandoned wells.

(10) A one-way automatic safety value shall be installed at the surface of all injection wells to prevent flow-back of the injected gas during an emergency, start-up or shut-down operations.

(11) Injection shall be accomplished through fiberglass-lined tubing and a nickel plated packer. The packer shall be set as close as practical to the uppermost injection perforations or casing shoe (of any open hole completion), so long as the packer set point remains below the top of the Grayburg formation.

(12) The casing-tubing annulus shall be filled with an inert packer fluid containing biocide and corrosion inhibitors. A gauge or approved leak-detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer.

(13) The operator shall use a special type of cement on all new injection wells that is designed to withstand the corrosive environment. The cement design shall contain

more than three percent (3%) tricalcium aluminate (C3A) in this High Sulfate Resistance (HSR) environment.

(14) The operator is not required to run a cement bond log on a producing well each time the rods and/or tubing are pulled from the well. However, prior to placing any well on injection, a cement bond log shall be run on said well and copies of all cement bond logs shall be sent to the Division's Hobbs District Office. If any well is found to have inadequate casing cement bond, such measures as may be necessary to prevent leakage or migration of fluids within the wellbore shall be taken before placing the well on injection.

(15) Prior to commencing injection operations, the casing in each of the injection wells within the expanded Phase I Area of the North Hobbs Unit shall be pressure tested throughout the interval from the surface down to the proposed packer setting depth to assure the integrity of such casing.

(16) A mechanical integrity test shall be conducted on all injection wells once every two years.

(17) Pursuant to NMAC 19.15.25.13.E, a mechanical integrity test shall be conducted on all temporarily-abandoned wells equipped with real-time pressure monitoring devices once every five years.

(18) Injection operations shall be conducted in a closed loop system, and the trucking of fluids is not allowed.

(19) Oxy shall not commence gas injection operations in the North Hobbs Unit Well No. 231 (API No. 30-025-07545) in the SE/4 NW/4 (Unit F) of Section 33 of Township 18 South, Range 38 East, until Oxy adds additional cement behind the production casing across the fresh water zone and provides a cement bond log to the Division's Hobbs District office.

(20) The operator shall immediately notify the supervisor of the Division's Hobbs District Office of the failure of any tubing, casing or packer in any of the injection wells, or the leakage of water, oil or gas from or around any producing or plugged and abandoned well within the project area, and shall promptly take all steps necessary to correct such failure or leakage.

(21) Oxy shall maintain recorded data from its SCADA system for the North Hobbs Unit for inspection by the Division for a reasonable period of time to be determined and agreed upon through consultation between Oxy and the Division's Hobbs District Office.

(22) The hydrogen sulfide contingency plan for the North Hobbs Unit shall be reviewed and amended as necessary pursuant to NMAC 19.15.11.9.F.

(23) The North Hobbs Grayburg-San Andres Unit Pressure Maintenance Project is hereby certified as an enhanced oil recovery project and as a tertiary recovery project pursuant to the Recovery Act and Rules, and the expanded Phase I Area of the North Hobbs Unit is designated as the area to be affected by the enhanced oil recovery project. To be eligible for the recovered oil tax credit, the operator shall advise the Division of the date and time CO2 injection commences within the expanded Phase I Area and at that time the Division will certify the project to the New Mexico Taxation and Revenue Department.

(24) At such time as a positive production response occurs, and within seven years from the date the project was certified to the New Mexico Taxation and Revenue Department, the applicant must apply to the Division for certification of a positive production response pursuant to the Recovery Act, NMSA 1978, Section 7-29A-3 and NMAC 19.15.6.8.E. This application shall identify the area benefiting from enhanced oil recovery operations and the specific wells eligible for the recovered oil tax rate. The Division may review the application administratively or set it for hearing. Based upon the evidence presented, the Division will certify to the New Mexico Taxation and Revenue Department those wells that are eligible for the recovered oil tax rate. Pursuant to NMAC 19.15.6.8.F, Oxy must also report annually to the Division to confirm that the project remains a viable enhanced oil recovery project.

(25) Jurisdiction of this case is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on this 22nd day of May, 2014.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ROBERT BALCH, Member

TERRY WARNELL, Member

JAMI BAILEY, Chair

SEAL

Exhibit A
List of Proposed Project Injectors by Qtr/Qtr Section

Well Name	API Number	Surface Location				Injection Interval	Proposed Injectant
		Section	Unit Letter	Township & Range	Footage Location		
TBD	TBD	14	A	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	B	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	C	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	D	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	E	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	F	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	G	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	H	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	I	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	J	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	K	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	L	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	M	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	N	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	O	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	14	P	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	A	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	B	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	C	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	D	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	E	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	F	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	G	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	H	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	I	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	J	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	K	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	L	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	M	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	N	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	O	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	23	P	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	26	A	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	26	B	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	26	H	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	C	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	D	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	E	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	F	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	I	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	J	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	K	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	L	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water

Page 1 of 4

Exhibit A
List of Proposed Project Injectors by Qtr/Qtr Section

Well Name	API Number	Surface Location Section	Unit Letter	Township & Range	Footage Location	Injection Interval	Proposed Injectant
TBD	TBD	13	M	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	N	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	O	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	13	P	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	A	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	B	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	C	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	D	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	E	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	F	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	G	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	H	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	I	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	J	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	K	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	L	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	M	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	N	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	O	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	24	P	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	A	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	B	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	C	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	D	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	E	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	F	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	G	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	H	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	I	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	J	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	K	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	L	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	M	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	N	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	O	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	25	P	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	A	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	B	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	C	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	F	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	G	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	H	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	36	I	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water

Exhibit A
List of Proposed Project Injectors by Qtr/Qtr Section

Well Name	API Number	Surface Location				Injection Interval	Proposed Injectant
		Section	Unit Letter	Township & Range	Footage Location		
TBD	TBD	36	J	18-S ; 37-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	18	M	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	18	N	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	18	O	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	18	P	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	A	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	B	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	C	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	D	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	E	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	F	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	G	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	H	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	K	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	19	L	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	D	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	E	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	F	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	I	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	J	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	K	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	L	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	M	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	N	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	30	O	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	30	P	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	A	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	B	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	C	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	31	D	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	31	E	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	31	F	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	31	G	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	H	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	I	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	J	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	K	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	31	L	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	31	M	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	N	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	O	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	31	P	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	17	E	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water

Exhibit A
List of Proposed Project Injectors by Qtr/Qtr Section

Well Name	API Number	Surface Location: Section	Surface Location: Unit Letter	Surface Location: Township & Range	Surface Location: Footage Location	Injection Interval	Proposed Injectant
TBD	TBD	17	K	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	17	L	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	17	M	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	17	N	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	20	C	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	20	D	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	20	E	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
TBD	TBD	20	F	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
TBD	TBD	20	L	18-S ; 38-E	TBD	3698' - 4500'	Produced Gas/CO2/Water
NHU-29A	TBD	29	I	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
NHU-28A	TBD	28	K	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water
NHU-28B	TBD	28	L	18-S ; 38-E	TBD	3698' - 4500'	Purchased CO2/Water

Exhibit B
List of Proposed Project Injectors (Existing Wells)

Well Name	API Number	Surface Location				Current Status	Injection Interval	Proposed Injectant
		Section	Unit Letter	Township & Range	Footage Location			
NHU 28-231	30-025-07421	28	K	18-S ; 38-E	1325' FSL & 1325' FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 28-232	30-025-28882	28	K	18-S ; 38-E	2300 FSL & 1350 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-422	30-025-28268	33	H	18-S ; 38-E	2181 FNL & 498 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-432	30-025-28269	33	I	18-S ; 38-E	1842 FSL & 1029 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 32-431	30-025-07537	32	I	18-S ; 38-E	2310 FSL & 330 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 32-432	30-025-26974	32	I	18-S ; 38-E	1400 FSL & 1300 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 32-132	30-025-27139	32	L	18-S ; 38-E	1400 FSL & 1300 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 32-142	30-025-28265	32	M	18-S ; 38-E	610 FSL & 1210 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 32-341	30-025-07539	32	O	18-S ; 38-E	330 FSL & 2310 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 32-342	30-025-28266	32	O	18-S ; 38-E	457 FSL & 1437 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-342	30-025-28267	33	O	18-S ; 38-E	125 FSL & 2730 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 31-441	30-025-07498	31	P	18-S ; 38-E	330 FSL & 330 FEL	TA	3698' - 4500'	Purchased CO2/Water
NHU 33-142	30-025-28411	33	M	18-S ; 38-E	1250 FSL & 185 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-312	30-025-29199	33	B	18-S ; 38-E	151 FNL & 1702 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-211	30-025-07564	33	C	18-S ; 38-E	330 FNL & 2310 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-212	30-025-29026	33	C	18-S ; 38-E	205 FNL & 1420 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
[illegible] 33-222	30-025-26975	33	F	18-S ; 38-E	1520 FNL & 1470 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
N[illegible] 33-322	30-025-27169	33	G	18-S ; 38-E	1435 FNL & 1670 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-323	30-025-28951	33	G	18-S ; 38-E	2525 FNL & 1453 FEL	Producer	3698' - 4500'	Purchased CO2/Water
NHU 33-534	30-025-34373	33	J	18-S ; 38-E	2415 FSL & 2200 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-231	30-025-07545	33	F	18-S ; 38-E	2310 FSL & 1320 FWL	Water Injector	3698' - 4500'	Purchased CO2/Water
NHU 33-232	30-025-27169	33	K	18-S ; 38-E	1435 FNL & 1670 FEL	Water Injector	3698' - 4500'	Purchased CO2/Water

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

APPLICATION OF OCCIDENTAL PERMIAN LIMITED PARTNERSHIP TO AMEND ORDERS R-4934 AND R-4934-E GOVERNING THE SOUTH HOBBS GRAYBURG-SAN ANDRES PRESSURE MAINTENANCE PROJECT TO ALLOW THE INJECTION OF CARBON DIOXIDE AND PRODUCED GASES, TO MODIFY THE SURFACE INJECTION PRESSURE, TO OBTAIN OTHER RELIEF, AND TO QUALIFY THIS EXPANSION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE NEW MEXICO ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO.

CASE NO. 14981
ORDER NO. R-4934-F

ORDER OF THE COMMISSION

This case comes before the New Mexico Oil Conservation Commission ("Commission") on the application of Occidental Permian Limited Partnership ("Oxy") to amend Order No. R-4934, as amended. The Commission, having conducted a hearing on May 9 and 10, 2013, at Santa Fe, New Mexico, and having considered the testimony and the record in this case, enters the following findings, conclusions and order.

THE COMMISSION FINDS THAT:

1. Due public notice has been given, and the Commission has jurisdiction of this case and its subject matter.

2. Under Order No. R-4934, issued in Case No. 5372 on December 3, 1974, the Commission authorized the injection of water into the Grayburg and San Andres formations and adopted Special Rules and Regulations for the South Hobbs Grayburg-San Andres Pressure Maintenance Project for certain acreage in Townships 18 and 19 South, Range 38 East, Lea County, New Mexico.

3. In May of 1984, under Order No. R-4934-E, the New Mexico Oil Conservation Division ("Division") amended the Special Rules and Regulations governing the South Hobbs Grayburg-San Andres Pressure Maintenance Project to what they are currently today.

4. Occidental Permian Limited Partnership is the current operator of the South Hobbs Grayburg-San Andres Pressure Maintenance Project. The acreage subject to the current waterflood operations consists of the following acreage in Lea County, New Mexico (hereinafter the "South Hobbs Project Area"):

BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. C-10
Submitted by: Goodnight Midstream Permian, LLC
Hearing Date: September 23, 2024
Case Nos. 23614-23617, 23775,
24018 – 24020, 24025, 24123

TOWNSHIP 18 SOUTH, RANGE 38 EAST, NMPM
Section 33: SE/4 SE/4
Section 34: SW/4 and W/2 NW/4

TOWNSHIP 19 SOUTH, RANGE 38 EAST, NMPM
Sections 3, 4, and 5: All
Section 6: N/2 and SE/4
Section 8: N/2 NW/4, E/2 NE/4, and N/2 SE/4
Section 9: N/2, N/2 SW/4, and SE/4
Section 10: All
Section 11: SW/4 SW/4
Section 14: W/2 NW/4
Section 15: All
Section 16: NE/4 NE/4

5. In April of 2009, under Administrative Order IPI-340, the Division approved Oxy's request to utilize 1100 psi as the maximum surface injection pressure for water in the South Hobbs Project Area.

6. Oxy is also the operator of the North Hobbs Grayburg San Andres Unit, which is adjacent to and to the north of the South Hobbs Project Area. The North Hobbs Grayburg San Andres Unit and the South Hobbs Project Area are collectively referred to as the "Hobbs Field".

7. Under Order No. R-6199-B, entered in Case No. 12722 on October 22, 2001, the Division authorized the conversion of a portion of the North Hobbs Grayburg San Andres Unit (the "Phase I Area") from a waterflood pressure maintenance project to a carbon dioxide gas tertiary recovery injection project in the Grayburg and San Andres formations.

8. Oxy now seeks authority to convert the South Hobbs Project Area to a similar carbon dioxide gas tertiary recovery injection project, and therefore requests the following relief from the Commission:

(a) to approve the injection of carbon dioxide (CO2), and the reinjection of produced CO2, water and gases including methane, natural gas liquids and hydrogen sulfide (H2S) in the South Hobbs Project Area;

(b) to provide for a surface injection pressure limit for CO2, produced gases and water based on friction pressure losses down the tubing and the lower density of gas as compared to water as follows: 1100 psi for water injection, 1250 psi for CO2 only injection, and 1770 psi for produced gas injection;

(c) to the extent that a limiting gas-oil ratio applies to an enhanced oil recovery project, to increase that limit above that allowed by 19.15.20.13 NMAC to 75,000 cubic feet of gas per barrel of oil produced;

(d) to allow an exception to the one-year commencement of injection required by 19.15.26.12.C NMAC for the South Hobbs Project Area;

(e) to provide that for any approved injection well that commences injection operations more than five years after approval of this request, that Oxy submit a statement that there have been no substantive changes to the area-of-review information submitted to the Division with its Application, or a statement describing any substantive changes;

(f) to provide for a five-year frequency for the mechanical integrity tests required for temporarily-abandoned wells that are equipped with real-time pressure monitoring devices pursuant to 19.15.25.13.E NMAC;

(g) to modify the packer setting depth required by Rule 10 of the Special Rules for the South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project to allow for the packer to be set anywhere above the uppermost injection perforations or casing shoe, provided the packer is set below the top of the Grayburg Formation;

(h) to remove the requirement in Rule 15 of the Special Rules for the South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project that a cement bond log be run prior to placing a well on injection or at any time the rods and/or tubing are pulled from any producing well;

(i) to allow for the administrative approval of additional injection wells into the Grayburg and San Andres formations underlying the South Hobbs Project Area; and

(j) to qualify this expansion of injection authority for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, NMSA 1978, Sections 7-29A-1 to 7-29A-5 (Laws 1992, Chapter 38, Sections 1 through 5) ("Recovery Act"), and the rules of the Commission, 19.15.6 NMAC ("Rules").

9. The Division appeared at the hearing, examined Oxy's witnesses, and offered a Pre-Hearing Statement with sworn written testimony from Richard Ezeanyim, a registered petroleum engineer and a Bureau Chief within the Division.

10. Malcolm Coombes, a surface owner within the South Hobbs Project Area, submitted a Pre-Hearing Statement and opposed the application because the project would endanger human health and safety and possibly harm the value of his land. Mr. Coombes appeared at the hearing through counsel. After examining Oxy's initial witness, Mr. Coombes, through his counsel, indicated that he had no objection to Oxy's application and did not participate further in the case.

11. Big Al Oil & Gas submitted a letter protesting the application but did not appear at the hearing or offer any testimony or exhibits. The Economic Development Corporation of Lea County submitted a resolution in support of the application.

12. Oxy presented seven witnesses in support of its application: Richard Foppiano, a petroleum engineer employed by Oxy with expertise in oil and gas regulatory matters and health and safety issues; Jerad Brockman, Oxy's project manager for the South Hobbs Project Area with expertise in oil and gas production engineering; Randy Stillwell, a senior geologic advisor for Oxy with expertise in petroleum geology; Scott Hodges, Oxy's operations supervisor for the South Hobbs Project Area; Krishna Chokkarapu, a facilities and construction engineer employed by Oxy with special expertise in the design and engineering of CO_2 and produced gas surface facilities for EOR projects; Kelley Montgomery, Oxy's regulatory consultant with expertise in oil and gas production engineering and environmental engineering; and Pat Sparks, Oxy's petroleum landman who directed a team of brokers to address the notice requirements for the application. These witnesses discussed and presented power-point slides, maps, diagrams, and other material that comprised a total of seventeen exhibits.

13. Oxy's witnesses provided testimony and presented exhibits addressing the following topics:

(a) Oxy's extensive experience with oil and gas operations, including the handling of H_2S and CO_2 flooding operations in the Permian Basin;

(b) How enhanced oil recovery projects utilize the injection of CO_2, water and produced gases to recover additional oil that is not recovered by primary and secondary recovery operations;

(c) How enhanced oil recovery projects are designed and implemented;

(d) How the gas injection operations necessary for enhanced oil recovery projects differ from acid gas disposal operations;

(e) The capital costs and associated development plans to convert the South Hobbs Project Area from a secondary waterflood project to an enhanced oil recovery project;

(f) The injection and production well patterns Oxy intends to utilize in the South Hobbs Project Area;

(g) The location and nature of the additional surface facilities Oxy intends to install in the South Hobbs Project Area;

(h) The projected timetable for the installation of key components of the enhanced oil recovery project and the anticipated commencement date of CO_2 injection operations;

(i) The effect that an enhanced oil recovery project has on the gas-oil ratio over time;

(j) How step rate tests were utilized to determine the appropriate surface injection pressure limits for water, CO2 and produced gases;

(k) The injection pressure control devices Oxy intends to utilize on its injection wells;

(l) The redundant pressure controls Oxy intends to utilize in the South Hobbs Project Area;

(m) Oxy's supervisory control and data acquisition (SCADA) system, and how it will be utilized to provide constant monitoring of temperature, water content, pressures, H2S levels and gas content in the South Hobbs Project Area;

(n) How Oxy intends to monitor the reservoir pressure to ensure that it remains just above the miscibility pressure;

(o) The need for additional flexibility in the packer setting depth than what is currently allowed by Rule 10 of the Special Rules for the South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project;

(p) The geology underlying the South Hobbs Project Area, the location of the fresh water zones and the impermeable barriers that exist between the injection interval and the fresh water zones;

(q) That a Division approved H2S contingency plan is in place that includes the South Hobbs Project Area;

(r) Oxy's downhole corrosion mitigation efforts, including the use of corrosion resistant tubing, packers and inert packer fluid in the annulus;

(s) Oxy's mechanical integrity program for the design, engineering, construction and maintenance of CO2 and produced gas injection facilities for enhanced oil recovery projects;

(t) The NACE Standard MRO175 set forth in NMAC 19.15.11.14 and Oxy's compliance with that standard for the injection facilities in the South Hobbs Project Area;

(u) The additional corrosion inhibition and mitigation efforts Oxy will utilize for the installation, construction and maintenance of the injection facilities in the South Hobbs Project Area;

(v) The production history of the South Hobbs Project Area and the forecasted additional oil, gas and water production;

(w) The condition of the existing injection wells and design plans for additional injection wells in the South Hobbs Project Area;

(x) Oxy's plans to obtain additional information and address, as necessary, the cementing condition of the Herradura Well No. 3 (API No. 30-022-35933), a Chevron operated well in the southeast corner of the South Hobbs Project Area;

(y) The extensive knowledge of the wells within the area of review, the amount of time and effort devoted to the area of review analysis, and the absence of a need to update the area of review analysis for any injection wells that commence injection over the next five years;

(z) The time frame for mechanical integrity tests for temporarily-abandoned wells under NMAC 19.15.25.12 and the absence of a need for more frequent testing for wells equipped with real-time pressure monitoring devices;

(aa) The extensive knowledge concerning the cementing conditions for wells within the South Hobbs Project Area, the current cement bond log requirements under Rule 15 of the Special Rules for the South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project, and the absence of a need to run cement bond logs any time the rods and/or tubing are pulled from any producing well in the project area;

(bb) The methodology, time frame and effort involved to ascertain the parties entitled to notice of the hearing on Oxy's application;

(cc) The number and identification of the parties notified of the hearing either by certified mail or by newspaper publication; and

(dd) Oxy's meetings with the City of Hobbs concerning its proposed tertiary recovery project in the South Hobbs Project Area.

14. The Division's Environmental Bureau has approved a hydrogen sulfide contingency plan that covers the South Hobbs Project Area.

15. The geologic evidence established the following with respect to the Grayburg and San Andres formations underlying the South Hobbs Project Area and the adjacent North Hobbs Grayburg San Andres Unit :

(a) These formations consist of a layered, anticlinal structure that acts as a natural trapping mechanism for oil, as well as any injected fluids.

(b) These formations are separated from the fresh water zones by over 3,500 feet.

(c) The upper portion of the Grayburg formation consists of 150 to 200 feet of impermeable anhydrite and limestone.

(d) Various additional layers of impermeable anhydrite, salt, shale and limestone exist between these injection formations and the fresh water zones.

(e) No geologic faults or other natural means exist in this area by which injected fluids could communicate with the shallower fresh water zones.

16. With respect to the proposed injection wells and the existing wells within the area of review for the South Hobbs Project Area, the evidence established that:

(a) The existing injection wells in the South Hobbs Project Area are sufficiently cased and cemented to prevent the migration of injection fluids out of the proposed injection interval.

(b) Oxy's design for additional injection wells in the South Hobbs Project Area will provide sufficient casing and cement to prevent the migration of injection fluids out of the proposed injection interval.

(c) With the possible exception of the Chevron operated Herradura Well No. 3 (API No. 30-022-35933), the remaining wells within the area of review are sufficiently cased and cemented to prevent migration of the injection fluids out of the proposed injection interval.

(d) Oxy does not intend to commence injection within one-half mile of the Chevron operated Herradura Well No. 3 (API No. 30-022-35933) until further evaluation of the cement in this well and Oxy is able to demonstrate to the Division that sufficient casing and cement exists to prevent migration of the injection fluids out of the proposed injection interval.

17. The Division has reviewed Oxy's application and found the proposed tertiary recovery project will prevent waste, protect correlative rights, is in the interest of conservation, and will provide a reasonable level of protection to human health and the environment.

18. The evidence demonstrates it is prudent to implement tertiary recovery operations in the Grayburg and San Andres formations underlying the South Hobbs Project Area and that implementing this project will result in the recovery of additional oil that may otherwise not be recovered and wasted.

19. The evidence presented to the Commission over the course of two days demonstrates that Oxy's proposed tertiary recovery operations in the Grayburg and San

Andres formations underlying the South Hobbs Project Area will not pose an unreasonable threat to groundwater, the public health or the environment.

20. Oxy's request to implement a tertiary recovery project utilizing the injection of CO2 from outside sources, and produced water and produced gases from the Hobbs Field should be approved.

21. With respect to Oxy's requested maximum surface injection pressures for water, CO2 and produced gases, the evidence demonstrates:

(a) Division Order IPI-340 approved a maximum surface injection pressure of 1100 psi for water after an evaluation of step rate tests performed by Oxy in 2008.

(b) Water is more dense than CO2 and produced gases, thereby justifying higher surface injection pressures for these gases than that allowed for water.

(c) Oxy's proposed maximum surface injection pressures of 1250 psi for CO2 and 1770 psi for produced gases are based on the step rate tests performed in 2008 and take into account the hydrostatic pressure differences between the substances.

(d) Oxy's proposed maximum surface injection pressures of 1250 psi for CO2 and 1770 psi for produced gases will allow injection operations to be conducted well below the bottomhole parting pressures evidenced by the step-rate tests performed in 2008.

(e) Oxy's requested maximum surface injection pressures for water, CO2 and produced gases should be approved.

22. With respect to Oxy's request for an exception to the limiting gas-oil ratio set forth in NMAC 19.15.20.13, Oxy provided testimony that Rules 19.15.20.12 (Depth Bracket Allowables) and 19.15.20.13 (Gas Oil Ratio Limitation) should not apply to enhanced oil recovery projects.

23. With respect to Oxy's request for an exception to the one-year commencement of injection required by NMAC 19.15.26.12.C, the evidence establishes that due to the time frames associated with the design, procurement and construction of the necessary facilities, injection operations in the South Hobbs Project Area are not expected to commence before September of 2015. Accordingly, it is reasonable to allow for a three year period of time to commence injection operations.

24. Based on the extensive area of review analysis performed by Oxy, as well as the low level of activity in the subject area by other operators, the Commission finds it is unnecessary to update the existing area of review analysis for a period of five years.

However, if any well commences injection operations more than five years after the date of this order, Oxy should submit a statement to the Division that there have been no substantive changes to the area-of-review information submitted, or a statement describing any substantive changes.

25. Pursuant to NMAC 19.15.25.13.E, and based on the evidence presented on Oxy's SCADA system and proposed *real time pressure monitoring devices, the* Commission finds it is appropriate to conduct mechanical integrity tests on temporarily-abandoned wells equipped with real-time pressure monitoring devices once every five years.

26. Pursuant to NMAC 19.15.25.14, and based on the evidence presented on Oxy's SCADA system and proposed real-time pressure monitoring devices, the Commission finds it is appropriate to conduct mechanical integrity tests on injection wells in the South Hobbs Project Area once every two years as recommended by the Division.

27. The geologic and other evidence presented demonstrates Oxy should be allowed to set packers in injection wells in the South Hobbs Project Area anywhere above the uppermost injection perforations or casing shoes, so long as the packer is set below the top of the Grayburg formation.

28. With respect to Oxy's request to modify the cement bond log requirements under Rule 15 of the Special Rules for the South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project, the Commission finds that a cement bond log should be run prior to placing a well on injection, but agrees there is no need to run a cement bond log on a producing well each time the rods and/or tubing are pulled.

29. The Commission further finds that the remaining four additional requirements proposed by the Division in its prehearing statement are appropriate for the South Hobbs Project Area.

30. With respect to Oxy's request that its proposed expanded injection authority qualify for the recovered oil tax rate pursuant to the Recovery Act, the evidence establishes that:

(a) Oxy's planned enhanced oil recovery project in the South Hobbs Project Area should result in the recovery of an additional 33.2 million barrels of oil that may otherwise not be recovered, thereby preventing waste.

(b) The South Hobbs Project Area has been so depleted that it is prudent to apply enhanced recovery techniques to maximize the ultimate recovery of crude oil;

(c) The application is economically and technically reasonable and has not been prematurely filed; and

(d) The proposed tertiary recovery project meets all of the criteria for certification as a qualified "enhanced recovery project" under the Recovery Act and the Rules. NMSA 1978, Section 7-29A-4; 19.15.6.8.E NMAC.

31. The proposed tertiary recovery project will prevent waste, protect correlative rights, and should be approved with certain conditions.

THE COMMISSION CONCLUDES THAT:

1. The Commission is empowered to regulate the injection of natural gas or of any other substance into any pool in this state for the purpose of repressuring, cycling, pressure maintenance, secondary or any other enhanced recovery operations and to regulate the disposition of water produced or used in connection with drilling for or producing of oil or gas, and to regulate the disposition of nondomestic waste resulting from the treatment of natural gas or the refinement of crude oil to protect public health and the environment. NMSA 1978 § 70-2-12(B)(14, 15, 22). The Commission has a statutory duty to prevent waste and protect correlative rights. NMSA 1978 § 70-2-11(A).

2. Oxy has provided substantial evidence to support the approval of the authority to inject CO2, and produced water and produced gases into the South Hobbs Project Area subject to the conditions provided in this Order, which conditions are necessary to prevent waste and protect correlative rights and public health and the environment.

3. The Commission concludes Rules 19.15.20.12 (Depth Bracket Allowables) and 19.15.20.13 (Gas Oil Ratio Limitation) do not apply to enhanced oil recovery projects, and therefore, neither a limiting gas-oil ratio nor an oil allowable shall apply to this tertiary recovery project.

4. Rule 19.15.26.12(C) allows an extension of the one year deadline for injection authority for good cause. Oxy has provided substantial evidence concerning the size and complexity of the project to show good cause and to support the Commission extension of the deadline for initial injection to three years.

5. The Commission and the Division have the authority to certify "enhanced recovery projects" that are eligible for a "recovered oil tax rate" under the Enhanced Oil Recovery Act, NMSA 1978, Sections 7-29A-1 to -5 (1992) and under the Rules, 19.15.6 NMAC. The South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project, as expanded by this Order, meets the requirements for certification as an enhanced recovery project and a tertiary recovery project under the Recovery Act and the Rules. The South Hobbs Project Area shall be designated as the area to be affected by the enhanced recovery project.

IT IS THEREFORE ORDERED THAT:

1. The provisions of this order shall govern the tertiary recovery project described herein. The provisions of Orders Nos. R-4934 and R-4934-E remain applicable to the ongoing waterflood operations for the South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project, except to the extent that the governing provisions are inconsistent with this order.

2. Oxy is authorized to implement a tertiary recovery project by the injection of CO_2, and produced water and produced gases from the Hobbs Field into the Grayburg and San Andres formations underlying the following acreage, which shall be known as the South Hobbs Project Area:

TOWNSHIP 18 SOUTH, RANGE 38 EAST, NMPM
Section 33: SE/4 SE/4
Section 34: SW/4 and W/2 NW/4

TOWNSHIP 19 SOUTH, RANGE 38 EAST, NMPM
Sections 3, 4, and 5: All
Section 6: N/2 and SE/4
Section 8: N/2 NW/4, E/2 NE/4, and N/2 SE/4
Section 9: N/2, N/2 SW/4, and SE/4
Section 10: All
Section 11: SW/4 SW/4
Section 14: W/2 NW/4
Section 15: All
Section 16: NE/4 NE/4

3. The injection of CO_2, water and produced gases is initially authorized for the 30 existing injection wells and 23 additional injection wells listed on Exhibit "A" attached to this order. Application for approval of additional injection wells in the South Hobbs Project Area shall be filed in accordance with NMAC 19.15.26.8 and may be approved administratively by the Division Director without notice and hearing.

4. The injection authority granted herein for the wells shown on Exhibit "A" shall terminate three years after the date of this order if the operator has not commenced tertiary injection operations in the South Hobbs Project Area; provided, however, the Division, upon written request by the operator, may grant an extension for good cause. Furthermore, in accordance with NMAC 19.15.26.12.C (Abandonment of Injection Operations), whenever there is a one-year period of non-injection into all wells in the project area, the Division shall consider the project abandoned and the authority to inject shall automatically terminate.

5. For any injection well shown on Exhibit "A" in which tertiary injection operations commence more than five years after the date of this order, the operator shall submit to the Division either: (i) a statement certifying that there have been no

no substantive changes in the information furnished in support of the subject application concerning the status or construction of any well that penetrates the injection interval within the one half (1/2) mile area of review around the injection well; or (ii) a statement describing any substantive changes. This statement shall be submitted to the Division's Santa Fe office within a period no more than twelve months and no less than sixty days before injection operations commence in the well.

6. The injection wells or pressurization system within the South Hobbs Project Area shall be equipped with a pressure control device or acceptable substitute that will limit the surface injection pressure to no more than:

1100 psig for injection of water only;
1250 psig for injection of CO_2 only; and
1770 psig for injection of produced gases.

7. The Division Director may administratively authorize an increase in surface injection pressure upon a showing by the operator that such higher pressure will not result in the fracturing of the injection formation or confining strata.

8. The operator shall take all necessary steps to ensure that the injected gases and fluids enter only the Grayburg and/or San Andres formations and are not permitted to escape to other formations or to the surface from injection, production, or plugged and abandoned wells.

9. A one-way automatic safety value shall be installed at the surface of all injection wells to prevent flow-back of the injected gas during an emergency, start-up or shut-down operations.

10. Injection shall be accomplished through fiberglass-lined tubing and a nickel plated packer. The packer shall be set as close as practical to the uppermost injection perforations or casing shoe (of any open hole completion), so long as the packer set point remains below the top of the Grayburg formation.

11. The casing-tubing annulus shall be filled with an inert packer fluid containing biocide and corrosion inhibitors. A gauge or approved leak-detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer.

12. The operator shall use a special type of cement on all new injection wells that is designed to withstand the corrosive environment. The cement design shall contain more than three percent (3%) tricalcium aluminate (C_3A) in this High Sulfate Resistance (HSR) environment.

13. The operator is no longer required to run a cement bond log on a producing well each time the rods and/or tubing are pulled from the well. However, prior to placing any well on injection, a cement bond log shall be run on said well and copies of all cement bond logs shall be sent to the Division's Hobbs District Office. If any well

is found to have inadequate casing cement bond, such measures as may be necessary to prevent leakage or migration of fluids within the wellbore shall be taken before placing the well on injection.

14. Prior to commencing injection operations, the casing in each of the injection wells within the South Hobbs Project Area shall be pressure tested throughout the interval from the surface down to the proposed packer setting depth to assure the integrity of such casing.

15. A mechanical integrity test shall be conducted on all injection wells once every two years.

16. Pursuant to NMAC 19.15.25.13.E, a mechanical integrity test shall be conducted on all temporarily-abandoned wells equipped with real-time pressure monitoring devices once every five years.

17. Injection operations shall be conducted in a closed loop system, and the trucking of fluids is not allowed.

18. Oxy shall not commence injection operations anywhere within one-half (1/2) mile of the Chevron operated Herradura Well No. 3 (API No. 30-022-35933) until Oxy provides a cement bond log to the Division's Hobbs District Office demonstrating that adequate cement exists in this well to prevent migration of the injection fluids out of the proposed injection interval.

19. The operator shall immediately notify the supervisor of the Division's Hobbs District Office of the failure of the tubing, casing or packer in any of the injection wells, or the leakage of water, oil or gas from or around any producing or plugged and abandoned well within the project area, and shall promptly take all steps necessary to correct such failure or leakage.

20. Oxy shall maintain recorded data from its SCADA system for the South Hobbs Project Area for inspection by the Division for a reasonable period of time to be determined and agreed upon through consultation between Oxy and the Division's Hobbs District Office.

21. No limiting gas-oil ratio or oil allowable applies to this enhanced oil recovery project.

22. The hydrogen sulfide contingency plan for the South Hobbs Project Area shall be reviewed and amended as necessary pursuant to 19.15.11.9.F NMAC.

23. The South Hobbs Grayburg-San Andres Unit Pressure Maintenance Project is hereby certified as an enhanced recovery project and as a tertiary recovery project pursuant to the Recovery Act and the Rules. The South Hobbs Project Area is designated as the area to be affected by the enhanced recovery project. To be eligible for

the recovered oil tax rate, the operator shall advise the Division of the date and time C02 injection commences within the project area. At that time, the Division will certify the project to the New Mexico Taxation and Revenue Department.

24. At such time as a positive production response occurs, and within seven years from the date the project was certified to the New Mexico Taxation and Revenue Department, the applicant must apply to the Division for certification of a positive production response pursuant to the Recovery Act, NMSA 1978 Section 7-29A-3, and the Rules, 19.15.6.E NMAC. This application shall identify the area benefiting from enhanced oil recovery operations and the specific wells eligible for the recovered oil tax rate. The Division may review the application administratively or set it for hearing. Based upon the evidence presented, the Division will certify to the New Mexico Taxation and Revenue Department those wells that are eligible for the recovered oil tax rate. Oxy must also report annually to the Division to confirm that the project is still a viable EOR project as approved. 19.15.6.F NMAC.

25. Jurisdiction of this case is retained for the entry of such further orders as the Commission may deem necessary.

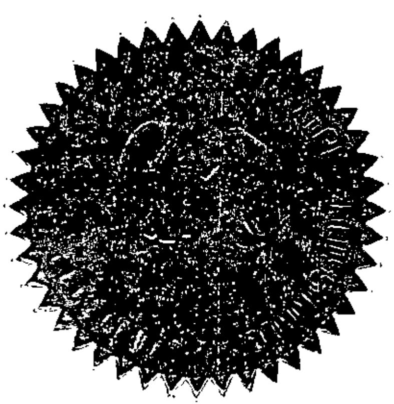
DONE at Santa Fe, New Mexico, on this 18th day of July, 2013.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ROBERT BALCH, Member

TERRY WARNELL, Member

JAMI BAILEY, Chair



SEAL

Case No. 14981
Order No. R-4934-F
Page 15

Exhibit "A"

List of Injectors in South Hobbs Unit Project
53 Total Injectors

No.	API Number	Section	Unit Letter	Township & Range	Footage Location	Proposed Injectants Purchased CO2/Water or Produced Gas/CO2/Water	Current Status
SHU 128	30-025-28332	3	D	19-S ; 38-E	335 FNL & 520 FWL	Purchased CO2/Water	Active Injector
SHU 240	30-025-35342	34	M	18-S ; 38-E	571 FSL & 1302 FWL	Purchased CO2/Water	Active Producer
SHU 36	30-025-07588	3	F	19-S ; 38-E	1980 FNL & 1980 FWL	Purchased CO2/Water	Active Injector
SHU 37	30-025-07584	3	G	19-S ; 38-E	1980' FNL & 2310' FEL	Purchased CO2/Water	P&A'd Injector
SHU 188	30-025-28982	5	K	19-S ; 38-E	1493 FSL & 1802 FWL	Produced Gas/CO2/Water	Active Producer
SHU 189	30-025-29085	5	J	19-S ; 38-E	1685 FSL & 2475 FEL	Produced Gas/CO2/Water	Active Producer
SHU 190	30-025-29082	5	I	19-S ; 38-E	1568 FSL & 1105 FEL	Produced Gas/CO2/Water	Active Producer
SHU 191	30-025-28983	4	L	19-S ; 38-E	1585 FSL & 395 FWL	Produced Gas/CO2/Water	Active Producer
SHU 140	30-025-28343	4	L	19-S ; 38-E	1485 FSL & 1245 FWL	Produced Gas/CO2/Water	Active Producer
SHU 141	30-025-28344	4	K	19-S ; 38-E	1478 FSL & 2595 FWL	Produced Gas/CO2/Water	Active Producer
SHU 142	30-025-28345	4	O	19-S ; 38-E	1310 FSL & 1370 FEL	Produced Gas/CO2/Water	Active Producer
SHU 145	30-025-28348	3	N	19-S ; 38-E	577 FSL & 1984 FWL	Purchased CO2/Water	Active Producer
SHU 71	30-025-07670	9	E	19-S ; 38-E	1650 FNL & 990 FWL	Produced Gas/CO2/Water	TA'd Injector
SHU 63	30-025-07662	9	C	19-S ; 38-E	660 FNL & 1980 FWL	Produced Gas/CO2/Water	Active Injector
SHU 154	30-025-28357	9	B	19-S ; 38-E	1163 FNL & 2600 FEL	Produced Gas/CO2/Water	Active Producer
SHU 155	30-025-28358	9	B	19-S ; 38-E	1158 FNL & 1568 FEL	Produced Gas/CO2/Water	Active Producer
SHU 156	30-025-28359	9	H	19-S ; 38-E	1370 FNL & 330 FEL	Produced Gas/CO2/Water	Active Producer
SHU 83	30-025-07668	9	J	19-S ; 38-E	1980 FSL & 1980 FEL	Produced Gas/CO2/Water	TA'd Injector
SHU 91	30-025-20047	9	P	19-S ; 38-E	990 FSL & 330 FEL	Produced Gas/CO2/Water	TA'd Producer
COOP 2	30-025-28305	4	O	19-S ; 38-E	645 FNL & 453 FWL	Purchased CO2/Water	Active Injector
COOP 3	30-025-28306	4	C	19-S ; 38-E	645 FNL & 2045 FWL	Purchased CO2/Water	Active Injector
COOP 4	30-025-28307	4	A	19-S ; 38-E	494 FNL & 1025 FEL	Purchased CO2/Water	Active Injector
COOP 5	30-025-28308	34	L	18-S ; 38-E	1980 FSL & 646 FWL	Purchased CO2/Water	Active Injector
COOP 6	30-025-28309	34	E	18-S ; 38-E	1950 FNL & 535 FWL	Purchased CO2/Water	Active Injector
COOP 9	30-025-28968	34	A	18-S ; 38-E	717 FNL & 651 FWL	Purchased CO2/Water	Active Injector
COOP 10	30-025-28969	34	L	18-S ; 38-E	2564 FSL & 1607 FWL	Purchased CO2/Water	Active Injector
11	30-025-28970	34	L	18-S ; 38-E	2500 FSL & 1660 FWL	Purchased CO2/Water	Active Injector
COOP 12	30-025-28971	34	N	18-S ; 38-E	636 FSL & 2348 FWL	Purchased CO2/Water	Active Injector
COOP 13	30-025-28972	3	B	19-S ; 38-E	505 FNL & 2560 FEL	Purchased CO2/Water	Active Injector
SHU 209	30-025-29522	8	D	19-S ; 38-E	265 FNL & 1090 FEL	Produced Gas/CO2/Water	Active Injector
SHU 92R	TBD	10	M	19-S ; 38-E	660 FSL & 600 FWL	Produced Gas/CO2/Water	Proposed New Drill - Vertical
SHU 95R	TBD	10	O	19-S ; 38-E	990 FSL & 2310 FEL	Produced Gas/CO2/Water	Proposed New Drill - Vertical
VP1	TBD	6	G	19-S ; 38-E	TBD	Purchased CO2/Water	Proposed New Drill - Vertical
VP2	TBD	6	F	19-S ; 38-E	TBD	Purchased CO2/Water	Proposed New Drill - Vertical
VSR2	TBD	15	G	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Vertical
VSR3	TBD	15	F	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Vertical
DSR1	TBD	4	J	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR2	TBD	4	J	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR3	TBD	4	J	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR4	TBD	4	K	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR5	TBD	4	K	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR6	TBD	4	K	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR7	TBD	4	K	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR8	TBD	5	L	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR9	TBD	5	L	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR10	TBD	5	L	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR11	TBD	5	L	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR12	TBD	10	O	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR13	TBD	10	O	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
DSR14	TBD	10	O	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
203	TBD	5	L	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
143	TBD	4	J	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional
P144	TBD	4	J	19-S ; 38-E	TBD	Produced Gas/CO2/Water	Proposed New Drill - Directional