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

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

APPLICATION OF 3BEAR FIELD SERVICES, LLC FOR AUTHORIZATION TO INJECT ACID GAS INTO THE PROPOSED LIBBY AGI #1 AND AGI #2 WELLS, SECTION 26, TOWNSHIP 20 SOUTH, RANGE 34 EAST, N.M.P.M., LEA COUNTY, NEW MEXICO

CASE NO. 20409
ORDER NO. R-20694

ORDER OF THE COMMISSION

THIS MATTER came before the New Mexico Oil Conservation Commission ("Commission") on the application of 3Bear Field Services, LLC ("3 Bear" or the "Applicant"). The Commission, having conducted a public hearing on June 6, 2019 in Santa Fe, New Mexico, and considered the testimony and the record in this case, as well as the arguments of the parties, and being otherwise fully advised, enter the following findings, conclusions and order on this 18th day of July, 2019.

FINDS THAT:

1. Notice has been given of the application and the hearing of this matter, and the Commission has jurisdiction of the parties and the subject matter herein.

2. On March 5, 2019, 3Bear filed an application (OCD Form C-108 and attachments), seeking authority to inject treated acid gas ("TAG") consisting of carbon dioxide ("CO_2") and hydrogen sulfide ("H_2S") from its Libby Gas Plant (the "Plant") into its proposed Libby Acid Gas Injection ("AGI") No. 1 well and its proposed Libby Acid Gas Injection ("AGI") No. 2 Well. The proposed Libby AGI No. 1 well will be a vertical well with a surface and bottom hole location at 1970 feet from the West line and 1475 feet from the South line of Section 26, Township 20 South, Range 34 East. The proposed Libby AGI No. 2 well will be a deviated well with a surface location at 1970 feet from the West line and 1910 feet from the South line of Section 26, Township 20 South, Range 34 East, and a bottom hole location of 1320 feet from the West line and 2275 feet from the South line of Section 26, Township 20 South, Range 34 East, N.M.P.M., Lea County, New Mexico. The target injection zones are located in the Devonian, Upper Silurian Wristen, and Fusselman formations, at an approximate depth interval of 14,900 feet to 16,400 feet below the surface at a maximum allowable surface operating pressure of 4,525 psig, for a maximum injection rate of 8 million standard cubic feet per day ("MMSCFD").

EXHIBIT 2

3. The Form C-108 Application was complete and contains all the information necessary to grant approval.

4. The surface on which the two wells are to be drilled is owned by the Applicant and the minerals owned by the federal government. The adjacent operators and the U.S. Bureau of Land Management support 3Bear's application.

5. The purpose of the proposed Class II injection wells is to dispose of natural gas processing wastes consisting of CO_2 and H_2S from the Applicant's Libby Gas Plant by injecting TAG into the target zones. It is estimated the TAG will consist of approximately 10-15 percent H_2S and 85-90 percent CO_2, although the relative concentrations will vary with inlet gas composition.

6. The two wells are intended as redundant wells to assure continuous operation of the Plant should one well require repairs. Under normal operations both wells may be operated simultaneously, or may be used independently.

7. The surface location of both wells will be located within the boundary of the Plant premises.

8. Applicant's Pre-Hearing Statement filed April 4, 2019, and Amended Pre-Hearing Statement filed May 30, 2019, both included a corrected page 11 evidencing the execution of the Application by Geolex, Inc. on behalf of Applicant.

9. Applicant provided personal notice via certified mail, return receipt requested, of its Application and the Commission hearing to all operators, surface owners, and lessees within a combined one-mile radius of the location for the proposed wells.

10. Pursuant to 19.15.4.9.B(3) NMAC, the Division provided public notice by publishing notice of 3Bear's application and the Commission hearing in a newspaper of general circulation in Lea County.

11. As of the date of this order, no objections to the application were filed. The Division entered an appearance in this matter, and presented five exhibits in support of the testimony offered by the Division's witness, Mr. Phillip Goetze. Mr. Goetze testified in support of approval of the application subject to incorporating the conditions set forth in the Division's Exhibit 5.

12. In support of its application, 3Bear presented direct testimony from two witnesses: one fact witness, Mr. Michael Solomon, 3Bear's Senior Vice President Engineering and Operations, and a technical witness, Mr. Alberto Gutierrez, RG President of Geolex, Inc.

13. Mr. Solomon provided background information for 3Bear, and testified that the Libby Gas Plant has been operating since the 3rd Quarter of 2018, and has a permanent full-time staff of about 19 people, with plans for future growth.

14. Mr. Solomon testified that currently there is an extensive LP/HP gathering line in place meeting industry standards for transporting sour gas, and all new steel pipes will be constructed and tested from compressor station to plant built to meet NACE SSC Region 3 Specs, including a metering system with electronic flow measurement and real-time SCADA communications aiding in leak detection and loss prevention.

15. Mr. Solomon further testified regarding 3Bear's proposed gas processing expansion for the Libby Plant which includes new compressor stations designed to meet NACE SSC Region 3 Specs, and compression (including AGI compressors) designed for Ariel Sour Level 2 Service.

16. Mr. Solomon testified as to the environmental and economic benefits of the Libby Plant including: (i) permanent sequestration of greenhouse gases, reducing the carbon footprint of oil and gas development by eliminating sulfur compounds and reducing GHG emissions to the atmosphere; (ii) providing construction jobs for building the facility and AGI wells; (iii) permanent operations jobs for the plant; (iv) improving worker safety at the Plant; and (iv) allowing increased royalties to flow to the State of New Mexico and federal government by increasing production capacity through providing additional gas treatment capacity.

17. Mr. Solomon testified that the proposed AGI wells are integral to the Libby Plant if the Plant is to significantly reduce net GHG emissions in southeast New Mexico, and that the two AGI wells will create redundancy by allowing the Plant to be operated without interruption should one well require maintenance or repairs.

18. The expert witness for 3Bear, Mr. Alberto Gutierrez, RG, testified that the injection of TAG through the proposed AGI wells will be at a maximum rate of 8.0 MMSCF per day, at a maximum operating surface pressure of 4,525 psig.

19. Mr. Gutierrez testified that with a safety factor of 100 percent, with total injection into a single well at 8.0 MMSCFD, the radius of influence for either well after injecting for 30-years will be 0.38 mile (2,027 feet).

20. Mr. Gutierrez testified the proposed injection zone is into the Silurian, Fusselman, Wristen and Devonian formations at depths of approximately 14,900 to 16,400 feet subsurface, and the zone provides a sufficient capacity and geologic seal to contain the injected TAG and prevent its migration into other zones. The injection zone is sufficiently isolated from any protectable groundwater sources and there is no evidence injection will impair existing or potential hydrocarbon production in the area. No faults or other geologic or manmade conduits will allow the treated injected acid gas to migrate out of the injection zone.

21. Fresh water will be protected by surface casing, which will extend to approximately 1950 feet below the surface. The salt zone, including the Salado formation, will be isolated by the first intermediate casing to approximately 3350 feet below the surface. All casing strings will be cemented to the surface, pressure tested and verified using 360-degree cement bond logs. The

casing and cement program will meet all U.S. Bureau of Land Management guidelines and requirements, in addition to all Division requirements.

22. The AGI wells annular space will be filled with corrosion-inhibited and biocide-treated diesel fuel.

23. Annular and injection tubing pressures and temperatures will be continuously monitored and recorded. The well will also be equipped with downhole pressure and temperature monitoring equipment. As detailed in the C-108, 3Bear also will do the following:

a. Obtain initial bottomhole pressure and temperature values after drilling and prior to commencing injection.
b. Perform a step-rate test and ten-day fall-off test prior to injection to provide baseline reservoir data.
c. Monitor injection pressure, temperature, injection rate, and annular pressure.
d. Use bottomhole reservoir and surface pressure/temperature data to develop a well-specific empirical relationship between observed surface and bottomhole data.
e. Use TAG and/or wellbore models to predict bottomhole pressure/temperature conditions based on measured surface data, and tested against the empirical relationships established by measured surface and bottomhole data.
f. In the event of any data gaps or bottomhole sensor failures, 3Bear will use TAG and/or wellbore models with empirical data to fill in missing bottomhole data.
g. In the event of an extended bottomhole pressure/temperature sensor failure 3Bear may perform periodic bottomhole pressure monitoring using slickline pressure tools only if data from such temporary device is necessary to fill in data for relevant analyses, and only at times when the well(s) is/are off-line.
h. After approximately five years of operation, 3Bear may perform additional testing to compare with the baseline measured prior to injection.
i. 3Bear will use the data obtained through the foregoing activities to conduct the periodic five-year reservoir performance analysis comparing actual reservoir performance against 3Bear's predicted performance.

24. 3Bear presented evidence that injection of the proposed TAG stream will protect the environment and human health, and will not cause waste or impair correlative rights.

25. The revised H_2S Contingency Plan for the Libby Plant is being prepared and will be submitted for approval by the Division prior to the commencement of operations.

26. Phillip Goetze, P.G. with the Division's Engineering Bureau, submitted the following exhibits to the Commission: (1) a plat depicting pending applications and approved SWD orders as of May 30, 2019 as based on the OCD's GIS database; (2) a copy of a letter to Mr. Goetze dated May 3, 2019 from Mr. Gutierrez and the results of the seismic survey review and fault slip probability assessment conducted by Geolex, Inc. enclosed with the letter (also submitted by 3Bear as Exhibit 5); (3) a 2019 inventory of UIC Class II Acid Gas Injection Wells located in

New Mexico; (4) the curriculum vitae of Mr. Goetze; and (5) a list of the Division's 18 conditions for approval of the application recommended by Mr. Goetze.

27. Mr. Goetze testified that the Division recommended 3Bear's application be approved as submitted subject to the standard conditions for Acid Gas Injection (UIC Class II Disposal Wells) and the additional conditions set forth in the Division's Exhibit 5.

28. The Division's additional conditions for approval, as modified at hearing by the Commissioners, are as follows:

a. Conduct a mechanical integrity test (MIT) on the proposed AGI well annually.

b. Conduct continuous monitoring of surface treated acid gas (TAG) injection pressure, temperature and rate, surface annular pressure and bottom-hole [i.e. "end of tubing"] temperatures and pressures inside the tubing and in the annulus.

c. Conduct a step-rate test and fall-off test on the completed well before commencing injection. The maximum injection pressure for the proposed well may be appropriately adjusted after a step-rate test with the approval of the Division Director.

d. Include a biocide and corrosion inhibited diesel in the annular fluid of the wells.

e. Keep a maintenance log that includes volumes of annular fluid (diesel) replacement activities in the annulus of the wells.

f. Incorporate temperature-activated controls to govern the temperatures of injected fluid within parameters set by the operator and provide an alarm system for those controls should the parameters be exceeded.

g. Equip the wells with a pressure-limiting device as well as a one-way safety valve (with the proper interior drift diameter) on the tubing approximately 250 feet below the surface.

h. Provide summary data on injection parameters monitored in Condition b. above, as requested by the Division, in quarterly reports. After one year of operation and if requested by the operator, the Division may approve submission of such reports on an annual cycle.

i. Prior to commencing injection, the operator shall prepare and secure approval of the Division's Environmental Bureau (Santa Fe office) of a hydrogen-sulfide contingency plan that complies with Rule 19.15.11.9 NMAC, and provide a map of associated gathering lines with a GIS overlay to the Division as part of the plan.

j. Thirty days prior to commencing injection, the operator shall coordinate with the Division to establish immediate notification parameters for annulus pressure and tubing and casing differential pressure at a set injection temperature.

k. Ninety days after commencing injection, the operator shall review the pre-injection immediate notification parameters with the Division. If the Division determines that the parameters require modification, new immediate notification parameters shall be developed and implemented in coordination with the Division.

l. The immediate notification parameters shall be reviewed jointly by the operator and the Division periodically, but not less frequently than once a year.

m. All well drilling logs (including mudlogs, electric logs and daily logs) and the static bottom-hole pressure measured at completion of drilling the well shall be submitted to the Division's District Office.

n. The operator shall every five years, once injection begins, provide the Division with a report that compares the reservoir pressures, volumes injected and projected TAG plume extent to those estimated in the C-108 application, together with summarizing the AGI wells' performance (including, but not limited to, injected volumes by fluid type and reservoir pressures) and potential calibration of models due to information collected during the prior five-year period. 3Bear will use data collected and analyses conducted pursuant to Paragraph 23, above, to prepare this analysis. The report shall include an updated model of current and projected plume migration and shall use the modeling technology in standard use at the time of the report and any available information about plume migration. At the request of the Commission, the operator shall provide in-person presentations of its data and analysis regarding the AGI wells' performance.

o. Concurrent with the report to be provided to the Division under Paragraph 28.n., above, the operator of the Libby AGI #1 and AGI #2 wells will present an analysis, with modeling if necessary, to demonstrate that the Libby AGI #1 and AGI #2 wells are not negatively influencing the adjacent Libby Berry Fee SWD #1 (API No. 300-25-44288) well, or that the adjacent Libby Berry Fee SWD #1 well is not negatively influencing the Libby AGI #1 and AGI #2 wells. Should this analysis demonstrate negative influence in either case, the operator shall submit a plan to the Division to resolve or eliminate any such negative influence. This plan may be reviewed and approved by the Division administratively.

p. All casing should have cement circulated to the surface, with an additional casing string through the Salado formation at an estimated depth of 2,100 feet to 3,350 feet from the surface.

q. Well construction should be designed for exposure to corrosive environment including, but not limited to, casing, casing cement, and the packer in proximity of injection interval.

r. The final reservoir evaluation should confirm that the open-hole portion of the AGI wells does not intersect the fault plane of any identified fault especially for those wells having the Devonian and Silurian sections for disposal intervals.

s. A requirement for the installation of a redundant AGI well within three years of injection commencing in the first AGI well.

t. Provide to the Division documentation of 3Bear's current bond in place with the Bureau of Land Management.

u. In the event 3Bear transfers ownership of the Libby AGI No. 1 and/or Libby AGI No. 2 wells, 3Bear shall seek approval of such change in ownership from the Division pursuant to 19.15.9.9 NMAC.

v. After thirty (30) years from the date of the Commission's order in this case, the authority granted by this order shall terminate unless applicant, or its successor in interest, shall make application before the Commission for an extension of its authority to inject.

CONCLUSIONS

1. The Commission has jurisdiction over the parties and the subject matter of this case.

2. Proper public notice has been given.

3. Proper individual notice has been given to all operators, surface owners, and lessees within a one-mile radius of the proposed injection well.

4. 3Bear's request for a maximum allowable operating pressure for injection of 4,525 pounds per square inch (psi) should be approved.

5. 3Bear's injection of CO_2 and H_2S can be conducted in a safe manner without causing waste, impairing correlative rights, negatively impacting oil and gas producing zones, or endangering fresh water, public health, or the environment.

6. 3Bear's proposed injection of CO_2 and H_2S is an environmentally superior means of disposing of CO_2 and H_2S because it will result in a net reduction in overall air emissions, including greenhouse gases, from the Libby Gas Plant and 3Bear facilities.

IT IS THEREFORE ORDERED THAT:

1. 3Bear Field Services, LLC's application is approved as provided in the Form C-108 as modified by the conditions addressed below. 3Bear is hereby authorized to drill and operate the Libby AGI No. 1 and Libby AGI No. 2 wells to be located in Section 26, Township 20 South, Range 34 East, N.M.P.M., Lea County, New Mexico, to dispose of TAG containing CO_2 and H_2S from 3Bear's Libby Gas Plant through injection into the Devonian, Upper Silurian, Wristen, and Fusselman formations at a maximum allowable surface operating pressure of 4,525 pounds per square inch and a maximum daily injection rate of 8 million standard cubic feet per day ("MMSCFD").

2. The Libby AGI No. 1 and Libby AGI No. 2 wells shall be constructed substantially in accordance with the description in the Form C-108 filed by the Applicant in this case, as amended, and as modified by the conditions set out in Findings Paragraph No. 28, above.

3. The maximum allowable operating pressure for each of the Libby AGI No. 1 and Libby AGI No. 2 wells shall be 4,525 psig. 3Bear shall conduct a step-rate test and fall-off test on the completed wells before commencing injection. Based on the step-rate test, the Division Director may allow an increase in the maximum allowable operating pressure.

4. The operator shall be required to conduct a MIT in accordance with the Division rules on each of the Libby AGI No. 1 and Libby AGI No. 2 wells once every year.

5. The casing-tubing annulus of each of the Libby AGI No. 1 and Libby AGI No. 2 wells shall be loaded with diesel fluid treated with corrosion inhibitors and biocides and each well equipped with a pressure gauge or approved leak-detection device to detect any leakage in the casing, tubing, or packer.

6. The operator shall keep a maintenance log that includes volumes of annular fluid (diesel) replacement activities in the annulus of the wells.

7. Thirty days prior to commencing injection, the operator shall coordinate with the Division to establish immediate notification parameters for annulus pressure and tubing and casing differential pressure at a set injection temperature. The operator shall provide an alarm system for those controls should the parameters be exceeded.

8. Equip the wells with a pressure-limiting device as well as a one-way safety valve (with the proper interior drift diameter) on the tubing approximately 250 feet below the surface.

9. Ninety days after commencing injection, the operator must review the pre-injection immediate notification parameters with the Division. If the Division determines that the parameters

require modification, new immediate notification parameters shall be developed and implemented in coordination with the Division.

10. The immediate notification parameters shall be reviewed jointly by the operator and the Division periodically, but not less than once a year.

11. The operator shall continuously monitor and record injection data including injection rates, injection and annular pressures, injection temperature, bottom hole injection pressure and temperature on a continuous basis and provide a quarterly report to the Engineering Bureau in the Division's Santa Fe Office and to the Division's District I Office. Each such report shall include the well name, location, API number and the number of this order. After one year 3Bear may apply to the Division to submit such data annually.

12. Prior to commencing injection, the operator shall prepare and secure approval of the Division's Environmental Bureau (Santa Fe office) of a hydrogen-sulfide contingency plan that complies with Rule 19.15.11.9 NMAC, and provide a map of associated gathering lines with a GIS overlay to the Division as part of the plan.

13. The operator shall every five years, once injection begins, provide the Division with a report that compares the reservoir pressures, volumes injected and projected TAG plume extent to those estimated in the C-108 application, together with summarizing the AGI wells' performance (including, but not limited to, injected volumes by fluid type and reservoir pressures) and potential calibration of models due to information collected during the prior five-year period. 3Bear may use data collected and analyses conducted pursuant to Paragraph 23, above, to prepare this analysis. The report shall include an updated model of current and projected plume migration and shall use the modeling technology in standard use at the time of the report and any available information about plume migration. At the request of the Commission, the operator shall provide in-person presentations of its data and analysis regarding the AGI wells' performance.

14. The operator's final reservoir evaluation should confirm that the open-hole portion of the AGI wells does not intersect the fault plane of any identified fault especially for those wells having the Devonian and Silurian sections for disposal intervals.

15. The operator shall install a redundant AGI well within three years of injection commencing in the first AGI well.

16. 3Bears shall provide to the Division documentation of its current bond in place with the Bureau of Land Management.

17. In the event 3Bear transfers ownership of the Libby AGI No. 1 and/or Libby AGI No. 2 wells, 3Bear shall seek approval of such change in ownership from the Division pursuant to 19.15.9.9 NMAC.

18. Concurrent with the report to be provided to the Division under Paragraph 28.n., above, the operator of the Libby AGI #1 and AGI #2 wells will present an analysis, with

modeling if necessary, to demonstrate that the Libby AGI #1 and AGI #2 wells are not negatively influencing the adjacent Libby Berry Fee SWD #1 (API No. 300-25-44288) well, or that the adjacent Libby Berry Fee SWD #1 well is not negatively influencing the Libby AGI #1 and AGI #2 wells. Should this analysis demonstrate negative influence in either case, the operator shall submit a plan to the Division to resolve or eliminate any such negative influence. This plan may be reviewed and approved by the Division administratively.

19. The Division Director shall have discretion to determine whether any modifications to this order that may be requested by 3Bear, or imposed by the U.S Bureau of Land Management, may be administratively approved by the Division or if a hearing before the Commission is required.

20. The injection authority herein granted shall terminate three years after the effective date of this order if the operator has not commenced injection operations pursuant hereto. The Division Director, upon written request of the operator submitted prior to the expiration of this order, may extend this time for good cause shown.

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

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

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

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

DR. THOMAS ENGLER, P.E.,MEMBER

JORDAN KESSLER, Esq., MEMBER

ADRIENNE SANDOVAL, M.E., CHAIR

SEAL