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

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

APPLICATION OF DCP MIDSTREAM, LP FOR AUTHORIZATION TO INJECT ACID GAS INTO THE PROPOSED ZIA AGI #2D WELL, SECTION 19, TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM, LEA COUNTY, NEW MEXICO.

CASE NO. 15528
ORDER NO. R-14207

ORDER OF THE COMMISSION

THIS MATTER came before the Oil Conservation Commission ("Commission") on the application of DCP Midstream, LP ("DCP" or the "Applicant"). The Commission, having held a public hearing on August 25, 2016, and considered the testimony, the record, and the arguments of the parties, and being otherwise fully advised, now, on this 6th day of September, 2016,

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 July 12, 2016, DCP filed an administrative 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") into the target injection zones located in the Devonian, Upper Silurian Wristen, and Fusselman Formations, at an approximate depth interval of 13,755 feet to 14,750 feet below the surface through the Zia AGI No. 2D well, at a maximum surface operating pressure of 5,028 pounds per square inch, a rate of 15.0 MMSCF per day TAG, and at a location in Section 19, Township 19 South, Range 32 East, NMPM, in Lea County, New Mexico. The proposed well will be drilled as a vertical well with the surface location at 1900 feet from the South line (FSL) and 950 feet from the West line (FWL) of Section 19.

3. On July 15, 2016, Geolex, Inc., submitted a revised Hydrogen Sulfide Contingency Plan amending the previously approved Zia II Gas Plant Rule 11 contingency plan to incorporate the proposed well. On July 22, 2016, the Division's Environmental Bureau approved and accepted those revisions.

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

5. An adjacent operator and the U.S. Bureau of Land Management, which owns the surface and minerals within the application area, support DCP's application.

6. The purpose of the proposed Class II injection well is to dispose of natural gas processing wastes consisting of CO_2 and H_2S from the Applicant's Zia II Gas Processing Plant ("Zia Gas Plant") by injecting TAG into the target injection zones. The TAG will consist of approximately 10 percent H_2S and 90 percent CO_2, although the proportions will vary with inlet gas composition changes over time.

7. The Zia AGI No. 2D well will have a surface location approximately 1900 feet from the South line and 950 feet from the West line of Section 19, Township 19 South, Range 32 East, NMPM, Lea County, New Mexico. The proposed AGI well will be located within the boundary of the Zia Gas Plant's premises.

8. On July 12, 2016, DCP requested that its C-108 Application be set for a hearing before the Commission on the August 25, 2016, docket.

9. On August 18, 2016, DCP filed with its Prehearing Statement and exhibits a corrected "Table A-1," marked as Exhibit 2, to replace the original Table A-1 filed with the Form C-108 Application.

10. DCP 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 one-mile radius of the location for the proposed well.

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

12. No objections to the application were filed. The Division entered an appearance in this matter, but presented no witnesses and no testimony. The Division does not oppose the application. It presented one exhibit, which provided the Division's recommendations for conditions of approval.

13. In support of the application, DCP presented direct testimony from two witnesses: one fact witness, Carlton D. "Tony" Canfield, DCP's Project Engineering Manager, and a technical expert witness, Alberto Gutiérrez, RG, President of Geolex, Inc.

14. DCP's Tony Canfield testified that the proposed Zia Gas Plant has a capacity to process up to 200 MMSCF per day of sour gas and that the design and operation of the Zia Gas Plant is dependent on AGI wells to dispose of the resultant TAG. DCP has been injecting TAG through Zia AGI No. 1 well, approved in Order No. R-13809, since

August 2015 into the Lower Cherry Canyon and Upper Brushy Canyon formations at a depth of approximately 5,470 to 6,070 feet below the surface.

15. Mr. Canfield testified that after commencing injection through the Zia AGI No. 1 well, an operator approached DCP about injecting TAG into a deeper formation. DCP identified the Devonian, Upper Silurian Wristen, and Fusselman Formations as a suitable candidate for injection of TAG through the proposed AGI No. 2D well. DCP intends to maintain authority to inject TAG through the Zia AGI No. 1 well in Order No. R-13809.

16. Mr. Canfield testified that approval of the Zia AGI No. 2D well is necessary to help meet growing production demand for sour gas processing and waste disposal, will increase processing safety and reliability by reducing unplanned plant outages and production well shut-ins, and will result in a net reduction of air emissions from DCP consolidated facilities, as well as Zia Gas Plant and field flaring.

17. Mr. Canfield testified that having redundant AGI wells at the Zia Gas Plant will increase plant reliability and allow DCP to continue to process and inject TAG while one acid gas well is off-line.

18. DCP expert witness Alberto Gutiérrez, RG, testified that injection of TAG through the proposed AGI well will be at a maximum rate of 15.0 MMSCF per day, and at a maximum operating surface pressure of 5,028 pounds per square inch.

19. Mr. Gutierrez testified that with a safety factor of 100 percent, or an additional 15.0 MMSCF per day per well, the radius of influence for the Zia AGI No. 2D well after injecting for thirty years would be approximately 0.39 miles. The radius of influence for the well, based on the actual authorized injection volumes, is expected to be approximately 0.28 miles after thirty years of injection. However, based on areas of higher porosity and permeability in the area observed in the seismic data, the TAG plume may occupy an equivalent area elongated north to south within this zone of higher porosity and permeability rather than a strictly radial pattern.

20. Mr. Gutierrez testified that the proposed injection 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. One fault, which has been identified and mapped in the area, is restricted vertically to the injection zone and cannot, therefore, serve as a conduit to zones outside the confines of the injection zone.

21. Fresh water will be protected by surface casing, which will extend to approximately 800 feet below the surface. The salt zone, including the Salado Formation, will be isolated by the first intermediate casing to approximately 2,550 feet below the surface, and the Capitan Aquifer will be completely isolated by the second intermediate casing, set at approximately 4,500 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 Oil Conservation Division requirements.

22. The AGI well's 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 also will be equipped with downhole pressure and temperature monitoring equipment. As detailed in Section 3.4 of the C-108, DCP also proposes 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, DCP 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, DCP may perform periodic bottomhole pressure monitoring using slickline pressure tools only if data from such a temporary device is necessary to fill in data for relevant analyses, and only at times when the well is off-line.

h. After approximately ten years of operation, DCP may perform another step-rate test and fall-off test to compare with the baseline measured prior to injection.

i. DCP may use the data obtained through the foregoing activities to conduct the periodic ten-year reservoir performance analysis addressed in Section 3.8 of the C-108, which would serve as the required ten-year comparison of actual reservoir performance against DCP's predicted performance, provided in decretal Paragraph 10, below.

24. DCP 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. William V. Jones, P.E., and Phillip Goetze, P.G., both of whom are with the Oil Conservation Division's Engineering Bureau, submitted a letter to the Commission, dated August 18, 2016, and marked as Exhibit 1, stating that they had conducted a review of the C-108 application and that DCP had addressed questions raised in the Division's review. The Division recommended that an order approving DCP's application incorporate those standard conditions and the standard conditions provided in Order Nos. R-13443-B and C.

26. Those conditions are as follows:

a. Conduct a mechanical integrity test ("MIT") on the proposed AGI well every year.

b. .Conduct continuous monitoring of surface TAG injection pressure, temperature and rate, surface annular pressure and bottomhole temperatures and pressures inside the tubing and annulus.

c. Conduct a step-rate test on the completed well before commencing injection. The maximum injection pressure for the proposed well shall be 5,028 pounds per square inch, which may be appropriately adjusted after a step-rate test.

d. Include a biocide component in the inert annular fluid of the well.

e. Keep a maintenance log of its annular fluid (diesel) replacement activities in the annulus of the well.

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

g. Equip the well with a pressure-limiting device as well as a one-way safety valve on the tubing approximately 250 feet below the surface.

h. Provide summary data on injection parameters monitored in item b. above, as requested by the Division in quarterly reports. After one year. the Division may approve submission of such reports annually upon request..

i. Conduct and implement all required air monitoring and safety measures pursuant to the updated H_2S Contingency Plan approved by the Division on July 22, 2016.

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 and the estimated static bottomhole pressure measured at completion of drilling the well shall be submitted to the Division's District I Office.

n. Provide a report at the completion of every tenth year of injection summarizing the AGI No. 2D well's performance and potential calibration of models due to information collected during the prior ten-year period.

27. In the letter from Mr. Jones and Mr. Goetze, the Division recommended two additional conditions:

o. The top of cement for the proposed seven-inch production casing should be circulated to the surface; and

p. The final reservoir evaluation should confirm that the open-hole portion of the AGI well does not intersect the fault plane of the identified fault in the Devonian section.

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. DCP's request for a maximum allowable operating pressure for injection of 5,028 pounds per square inch (psi) should be approved.

5. DCP'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. DCP'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 from the Zia Gas Plant and DCP facilities.

IT IS THEREFORE ORDERED THAT:

1. DCP's application is approved as provided in the Form C-108 as amended and modified by the conditions addressed below. Accordingly, DCP is hereby authorized to drill and operate the Zia AGI No. 2D well to be located in Section 19, Township 19 South, Range 32 East, NMPM, Lea County, New Mexico, to dispose of TAG containing CO_2 and H_2S from DCP's Zia Gas Plant through injection into the Devonian and Silurian Formations, at an approximate depth interval of 13,755 feet to 14,750 feet below the surface at a maximum injection pressure of 5,028 pounds per square inch and a maximum daily injection rate of 15 MMSCF per day.

2. The Zia AGI No. 2D well 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 agreed to by DCP and the Oil Conservation Division set out in Findings Paragraphs 26 and 27, above.

3. The maximum allowable operating pressure for the Zia AGI No. 2D well shall be 5,028 psi. DCP shall conduct a step-rate test on the completed well before commencing injection. Based on the step-rate test, the Division may allow an increase in the maximum allowable operating pressure.

4. DCP shall be required to conduct a MIT in accordance with Division rules on the Zia AGI No. 2D well once every year.

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

6. 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.

7. 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.

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

9. The operator shall record injection rates and pressures on a continuous basis and report these readings in a summary form on a quarterly basis 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 DCP may apply to the Division to submit such data annually.

10. The operator shall every ten 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, along with a summary of all the injection results to date. DCP 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.

11. The Division Director shall have discretion to determine whether any modifications to this order that may be requested by DCP, 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.

12. 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.

13. 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.

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

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ROBERT BALCH, MEMBER

PATRICK PADILLA, MEMBER

David R. Catanach

DAVID R. CATANACH, CHAIR

SEAL

Conditions of Approval

OPERATOR'S NAME:	DCP Midstream LP
LEASE NO.:	NM0149956
WELL NAME & NO.:	2-Zia AGI
SURFACE HOLE FOOTAGE:	1900'/S & 950'/W
BOTTOM HOLE FOOTAGE	1655'/S & 1655'/W
LOCATION:	Sec. 19, T. 19 S., R. 32 E.
COUNTY:	Lea County, New Mexico

A. DRILLING OPERATIONS REQUIREMENTS

The BLM is to be notified in advance for a representative to witness:

a. Spudding well (minimum of 24 hours)
b. Setting and/or Cementing of all casing strings (minimum of 4 hours)
c. BOPE tests (minimum of 4 hours)

☒ **Lea County**
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240, (575) 393-3612

1. A Hydrogen Sulfide (H2S) Drilling Plan shall be activated **500** feet prior to drilling into the **Delaware** formation. **As a result, the Hydrogen Sulfide area must meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.**

2. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval. **If the drilling rig is removed without approval – an Incident of Non-Compliance will be written and will be a "Major" violation.**

3. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works is located, this does not include the dog house or stairway area.

4. **The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.**

B. CASING

Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.).

The initial wellhead installed on the well will remain on the well with spools used as needed.

Centralizers required on surface casing per Onshore Order 2.III.B.1.f.

<u>Wait on cement (WOC) for Water Basin:</u>

After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least <u>8 hours</u>. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements. DURING THIS WOC TIME, NO DRILL PIPE, ETC. SHALL BE RUN IN THE HOLE.

Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.

No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.

<u>Risks:</u>

Possibility of Water Flows in the Capitan Reef, in the Salado and in the Artesia Group. Possibility of Lost Circulation in the Rustler, Capitan Reef, Red Beds, Delaware and in the Artesia Group.

1. The **20** inch surface casing shall be set at approximately **800** feet **(in a competent bed <u>below the Magenta Dolomite</u>, which is a <u>Member of the Rustler</u>, and if salt is encountered, set casing at least 25 feet above the salt)** and cemented to the surface.
    a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
    b. Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry.
    c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
    d. If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The minimum required fill of cement behind the **13 3/8** inch intermediate casing is:

☒ Cement to surface. If cement does not circulate see B.1.a, c-d above.

3. The minimum required fill of cement behind the **9 5/8** inch production casing is:

Operator has proposed DV tool at depth of 2650'. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range.

a. First stage to DV tool:

☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office before proceeding with second stage cement job. Operator should have plans as to how they will achieve circulation on the next stage.

b. Second stage above DV tool:

☒ Cement to surface. If cement does not circulate see B.1.a, c-d above.

4. The minimum required fill of cement behind the **7-5/8** and **7** inch intermediate casing is:

Operator has proposed DV tool at depth of 6350'. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range.

c. First stage to DV tool:

☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office before proceeding with second stage cement job. Operator should have plans as to how they will achieve circulation on the next stage.

d. Second stage above DV tool:

☒ Cement to surface. Operator to provide method of verification.

5. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

C. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API 53.

2. Variance approved to use flex line from BOP to choke manifold. Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. **Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.** If the BLM inspector questions the straightness of the hose, a BLM engineer will be contacted and will review in the field or via picture supplied by inspector to determine if changes are required (operator shall expect delays if this occurs).

3. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **surface casing shoe** shall be **2000 (2M)** psi.

4. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **9 5/8 inch intermediate casing** shoe shall be **10,000 (10M)** psi. **10M system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.**

5. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.
    a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead when specified), whichever is greater. However, if the float does not hold, cut-off cannot be initiated until cement reaches 500 psi compressive strength (including lead when specified).

    b. The tests shall be done by an independent service company utilizing a test plug **not a cup or J-packer**.

    c. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.

    d. The results of the test shall be reported to the appropriate BLM office.

    e. All tests are required to be recorded on a calibrated test chart. **A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.**

f. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.

g. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the **Wolfcamp** formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per Onshore Order No. 2.

D. DRILLING MUD

Mud system monitoring equipment, with derrick floor indicators and visual and audio alarms, shall be operating before drilling into the **Wolfcamp** formation, and shall be used until production casing is run and cemented.

E. WELL COMPLETION

A NOI sundry with the procedure to complete this well in compliance with BLM and NMOCD requirements shall be submitted and approved prior to commencing completion work.

The procedure will be reviewed to verify that the completion will allow the operator to restrict the injection fluid to the approved formation. NOTE: The sundry shall include data from the conventional core analysis and logs with detailed analysis of the reservoir seal depth related to the perforation interval and the packer setting depth. It may also need to include previously submitted information.

DO NOT install injection tubing until approval is received

NOTE: (include with NOI sundry) prior to beginning Acid Gas Injection at the well, the Operator shall provide all Operators of existing wells within a 1 mile radius with a notice of beginning injection operations and include a map of the possible worst case scenario H2S exposure area(s). BLM is to be copied on this notice mailing. (H2S Public Protection Plan)

An MIT test must be conducted annually and submitted to the BLM via subsequent sundry.

F. DRILL STEM TEST

If drill stem tests are performed, Onshore Order 2.III.D shall be followed.

G. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

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