STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL
RESOURCES DEPARTMENT

Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, New Mexico 87505

FORM C-108
Revised June 10, 2003

APPLICATION FOR AUTHORIZATION TO INJECT

I. PURPOSE: ________Secondary Recovery ________Pressure Maintenance __X__Disposal ________Storage
Application qualifies for administrative approval? ________Yes __X__No

II. OPERATOR: **Stakeholder Gas Services, LLC.**
ADDRESS: **777 E Sonterra Blvd., Suite 100, San Antonio, TX 78258**
CONTACT PARTY: **Alberto A. Gutierrez, R.G. - GEOLEX, INC.** PHONE: **(505)-842-8000**

III. WELL DATA: Complete the data required on the reverse side of this form for each well proposed for injection. Additional sheets may be attached if necessary. **A CROSS REFERENCE TO THE APPLICABLE SECTIONS OR APPENDICES IN THE ATTACHED C108 APPLICATION FOR EACH ROMAN NUMERAL BELOW IS SPECIFIED BY SECTION AND/OR APPENDIX NUMBERS.**

IV. Is this an expansion of an existing project? ________Yes __X__No
If yes, give the Division order number authorizing the project: ________________

V. Attach a map that identifies all wells and leases within two miles of any proposed injection well with a one-half mile radius circle drawn around each proposed injection well. This circle identifies the well's area of review. **SECTIONS 5 and 6; APPENDICES A and B.**

VI. Attach a tabulation of data on all wells of public record within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of completion, and a schematic of any plugged well illustrating all plugging detail.
SECTION 5; APPENDIX A.

VII. Attach data on the proposed operation, including:

1. Proposed average and maximum daily rate and volume of fluids to be injected; **SECTIONS 1, 2, and 3**
2. Whether the system is open or closed; **SECTIONS 1, 2, 4 and 7**
3. Proposed average and maximum injection pressure; **SECTIONS 1 and 3**
4. Sources and an appropriate analysis of injection fluid and compatibility with the receiving formation if other than reinjected produced water; and, **SECTIONS 3 and 4**
5. If injection is for disposal purposes into a zone not productive of oil or gas at or within one mile of the proposed well, attach a chemical analysis of the disposal zone formation water (may be measured or inferred from existing literature, studies, nearby wells, etc.). **SECTIONS 3 and 4**

*VIII. Attach appropriate geologic data on the injection zone including appropriate lithologic detail, geologic name, thickness, and depth. Give the geologic name, and depth to bottom of all underground sources of drinking water (aquifers containing waters with total dissolved solids concentrations of 10,000 mg/l or less) overlying the proposed injection zone as well as any such sources known to be immediately underlying the injection interval. **SECTIONS 4 and 5 and APPENDIX A**

IX. Describe the proposed stimulation program, if any. **N/A**

*X. Attach appropriate logging and test data on the well. (If well logs have been filed with the Division, they need not be resubmitted). **WELL ARE NOT YET DRILLED**

*XI. Attach a chemical analysis of fresh water from two or more fresh water wells (if available and producing) within one mile of any injection or disposal well showing location of wells and dates samples were taken. **SECTION 4.**

XII. Applicants for disposal wells must make an affirmative statement that they have examined available geologic and engineering data and find no evidence of open faults or any other hydrologic connection between the disposal zone and any underground sources of drinking water. **SECTION 7**

XIII. Applicants must complete the "Proof of Notice" section on the reverse side of this form. **APPENDIX B**

XIV. Certification: I hereby certify that the information submitted with this application is true and correct to the best of my knowledge and belief.

NAME: Alberto A. Gutierrez, C.P.G. TITLE: President, Geolex, Inc.®; Consultant to Stakeholder Midstream LLC

SIGNATURE: ________________ DATE: 7/10/2017

E-MAIL ADDRESS: aag@geolex.com

* If the information required under Sections VI, VIII, X, and XI above has been previously submitted, it need not be resubmitted. Please show the date and circumstances of the earlier submittal: **SEE ATTACHED APPLICATION**

DISTRIBUTION: Original and one copy to Santa Fe with one copy to the appropriate District Office

III. WELL DATA

A. The following well data must be submitted for each injection well covered by this application. The data must be both in tabular and schematic form and shall include:

(1) Lease name; Well No.; Location by Section, Township and Range; and footage location within the section.

AGI #1 Surface: 660' FSL, 1790' FWL Section 21, T16S, R35 E, - SECTIONS 1, 3 and 4. (Vertical Well)

AGI #2 Surface: 1980' FSL, 2080' FEL Section 21, T16S, R35 E, - SECTIONS 1, 3 and 4. (Vertical Well)

(2) Each casing string used with its size, setting depth, sacks of cement used, hole size, top of cement, and how such top was determined. **SEE SECTION 3 FOR PROPOSED WELL DESIGNS. FINAL AS-BUILTS WILL BE SUBMITTED WHEN PROPOSED WELLS ARE DRILLED AND COMPLETED.**

(3) A description of the tubing to be used including its size, lining material, and setting depth. **SECTION 3 AND FIGURE 7 FOR PROPOSED WELL DESIGN**

(4) The name, model, and setting depth of the packer used or a description of any other seal system or assembly used. **SECTION 3**

Division District Offices have supplies of Well Data Sheets which may be used or which may be used as models for this purpose. Applicants for several identical wells may submit a "typical data sheet" rather than submitting the data for each well.

B. The following must be submitted for each injection well covered by this application. All items must be addressed for the initial well. Responses for additional wells need be shown only when different. Information shown on schematics need not be repeated.

(1) The name of the injection formation and, if applicable, the field or pool name. **SECTIONS 1 and 4**

(2) The injection interval and whether it is perforated or open-hole. **SECTION 3**

(3) State if the well was drilled for injection or, if not, the original purpose of the well. **N/A- WELLS NOT YET DRILLED**

(4) Give the depths of any other perforated intervals and detail on the sacks of cement or bridge plugs used to seal off such perforations. **N/A**

(5) Give the depth to and the name of the next higher and next lower oil or gas zone in the area of the well, if any. **SECTIONS 4 and 5; APPENDICES A and B**

XIV. PROOF OF NOTICE

All applicants must furnish proof that a copy of the application has been furnished, by certified or registered mail, to the owner of the surface of the land on which the well is to be located and to each leasehold operator within one-half mile of the well location. **SECTION 5; APPENDIX B WE WILL NOTIFY OPERATORS AND LEASEHOLD OWNERS AND SURFACE OWNERS WITHIN THE AREA OF REVIEW PURSUANT TO NMOCD REGULATIONS AND WE WILL SUBMIT AFFIDAVITS OF PUBLICATION OF NOTICE AND CERTIFIED MAIL RETURN RECEIPTS AT HEARING.**

Where an application is subject to administrative approval, a proof of publication must be submitted. Such proof shall consist of a copy of the legal advertisement which was published in the county in which the well is located. The contents of such advertisement must include: **SEE APPENDIX B FOR DRAFT OF PUBLIC NOTICE – AFFIDAVIT OF PUBLICATION OF NOTICE FROM NEWSPAPER WILL BE SUBMITTED AT HEARING.**

(1) The name, address, phone number, and contact party for the applicant;

(2) The intended purpose of the injection well; with the exact location of single wells or the Section, Township, and Range location of multiple wells;

(3) The formation name and depth with expected maximum injection rates and pressures; and,

(4) A notation that interested parties must file objections or requests for hearing with the Oil Conservation Division, 1220 South St. Francis Dr., Santa Fe, New Mexico 87505, within 15 days.

NO ACTION WILL BE TAKEN ON THE APPLICATION UNTIL PROPER PROOF OF NOTICE HAS BEEN SUBMITTED.

NOTICE: Surface owners or offset operators must file any objections or requests for hearing of administrative applications within 15 days from the date this application was mailed to them.

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1.0 EXECUTIVE SUMMARY

On behalf of Stakeholder Gas Services LLC (Stakeholder), Geolex, Inc. ® (Geolex) has prepared and is hereby submitting a complete C-108 application for approval to drill, complete and operate two acid gas injection wells (Stakeholder AGI #1 and AGI #2) at the proposed Stakeholder Gas Plant in Section 21, T16S, R35E approximately 9 miles southwest of Lovington in Lea County, New Mexico (Figure 1).

Stakeholder intends to use these two wells to safely inject up to a maximum total of 6.8 MMSCFD of treated acid gas (TAG) distributed between both wells for at least 30 years. Geologic studies conducted for the selection of this location demonstrate that the proposed injection zone is readily capable of accepting and containing the proposed acid gas injection volumes within NMOCD's recommended maximum injection pressures.

The Stakeholder AGI #1 well will be drilled at a surface location approximately 660 feet from the south line (FSL) and 1,790 feet from the west line (FWL) of Section 21, Township 16 South, and Range 35 East in Lea County, New Mexico, and AGI #2 will be drilled approximately 1,980 feet from the south line (FWL) and 2,080 feet from the east line (FEL) of the same Section (Figure 2). The well spacing is approximately 2,050 feet. Both Stakeholder AGI wells are designed as vertical wells.

The proposed injection zone is the Premier Sand, which is found at a depth of approximately 4,700 to 4,800 feet in the lower portion of the Grayburg Formation.

Geolex has reviewed all of the surface owners, operators, leaseholders and mineral owners within one mile of the proposed AGI wells. The results of this review are provided in detail in Appendix B.

In preparing this C-108 application, Geolex conducted a detailed examination of all of the elements required to be evaluated in order to prepare and obtain approval for this application for injection. The elements of this evaluation included:

- Identification and characterization of all hydrocarbon-producing zones of wells that surround and are present on the proposed plant site (no changes from the original application).
- The depths of perforated pay intervals in those wells relative to the depth of the target injection zone.
- The past and current uses of the proposed injection interval.
- Total feet of net porosity in the proposed injection interval.
- The stratigraphic and structural setting of the targeted injection zone relative to any nearby active or plugged wells, and other wells penetrating the interval.
- The identification of surface owners within a one-half mile radius of the proposed injection well.
- The identification of all wells within a two-mile radius and of all operators, and of all wells within a one-mile area of review penetrating the injection zone.
- Identification and characterization of all active and plugged wells within the one-mile area of review of the proposed injection well.
- The details of the proposed injection operation, including general well design and maximum daily rates of injection and injection pressures.
- Sources and predicted composition of injection fluid and compatibility with the formation fluid of the injection zone.
- Location and identification of any fresh water bearing zones in the area and the depth and quality of available groundwater in the vicinity of the proposed well, including a determination that there are no structures which could possibly communicate the disposal zone with any known sources of drinking water.

- A Rule 11 Plan is being prepared for the facility. Prior to the initial injection from the new Stakeholder AGI #1, the Rule 11 Plan will be submitted to the NMOCD for approval.

Based upon this detailed evaluation, as summarized in this application, Geolex and Stakeholder have determined that the proposed AGI wells are a safe and environmentally-sound system for the disposal of acid gas into the proposed injection zone. Furthermore, the project provides additional environmental benefits by permanently sequestering a significant volume of CO_2 which would otherwise be released to the atmosphere if H_2S was flared or if a sulfur reduction unit (SRU) was operated at the Plant.

Our research has identified a porous and permeable sand unit, the Permian Premier Sand unit of the Grayburg Formation. These sands are sufficiently isolated from active pay zones above and below by hundreds of feet of tight, Permian limestones and shales.

The proposed wells will be essentially identical, and will be constructed using a three-casing string design, with the 13 3/8" surface casings advanced to a depth of approximately 600 feet to protect fresh water aquifer. The 9 5/8" intermediate casings will be set at approximately 3,340 feet to isolate the Salado, Tansill, and Yates formations. The 7" production casings will be advanced to approximately 4,900 feet in the San Andres Formation immediately below the targeted Premier Sand of the Grayburg (Section 3.3). The wells will also be completed incorporating Corrosion Resistant Alloys (CRA) in selected sections of the tubing and casing, and corrosion-resistant cement will be used for the lower half of the production strings. In addition, both wells will include bottom-hole pressure and temperature monitoring equipment.

At the anticipated reservoir conditions of 125° F and 2,000 psig, each MMSCFD of TAG will occupy a volume of approximately 2,700 cubic feet (480 barrels). At the anticipated maximum operational capacity of 6.8 MMSCFD, the compressed TAG will occupy 18,450 cubic feet (3,300 barrels) per day. After 30 years of operation, the TAG will occupy an area of approximately 690 acres in the proposed injection zone. As described further in Sections 3.1 and 3.2, the TAG is expected to migrate approximately 2,500 feet from each well after 30 years, if both wells receive essentially identical injection volumes. Using a safety factor of 100% (1,380 acres), the TAG has been calculated to migrate approximately 3,700 feet after 30 years. In both cases, the calculated TAG migration is well within the one mile area of review.

Twelve recorded oil and/or gas wells penetrating the injection zone were identified within one mile of the proposed AGI locations. Four of these wells are currently operating, and eight are plugged and abandoned. Completion and/or plugging details are provided in Section 5.0.

There is no current production in the proposed injection zone within the two-mile area.

Details on all operators, lessees, and surface and mineral owners within the one-half mile area of interest are included in Appendix B.

There is no permanent body of surface water within several miles of the plant. A search of the New Mexico State Engineer's files shows 6 water wells within one mile of the proposed AGI (see Section 4.6). Data from these wells show that groundwater occurs at a depth of approximately 60 to 280 feet, and is hosted by alluvium and Triassic formations. Available analyses of groundwater in the alluvium, from a well in Section 29, T19S, R37E (approximately 7 miles east of the proposed AGI well) showed a specific conductivity of 865 micromhos (Nicholson and Clebsch, 1961).

2.0 INTRODUCTION AND ORGANIZATION OF THIS C-108 APPLICATION

The completed NMOCD Form C-108 is included before the Table of Contents of this document and references appropriate sections where data required to be submitted are included herein.

This application organizes and details all of the information required by NMOCD and NMOCC to evaluate and approve the submitted Form C-108 – Application for Authorization to Inject. This information is presented in the following categories:

- A detailed description of the location, construction and operation of the proposed injection well (Section 3.0)
- A summary of the regional and local geology, the hydrogeology, and the location of drinking water wells within the area of review (Section 4.0)
- The identification, location, status, production zones, and other relevant information on oil and gas wells within the area of review (Section 5.0)
- The identification and required notification for operators and surface land owners that are located within the area of review (Section 6.0)
- An affirmative statement, based on the analysis of geological conditions at the site, that there is no hydraulic connection between the proposed injection zone and any known sources of drinking water (Section 7.0)
- References used in preparing this report (Section 8).

In addition, this application includes the following supporting information:

- **Appendix A:** Information on Oil and Gas Wells within Two Miles of Proposed Stakeholder AGI #1
- **Appendix B:** Land Information on Tracts within One-Half Mile of Proposed Stakeholder AGI #1
- **Appendix C:** Copies of Notice Letters, Documentation, and Affidavit of Publication of Newspaper Notice

3.0 PROPOSED CONSTRUCTION AND OPERATION OF STAKEHOLDER AGI #1 and AGI #2

TAG from the plant's sweeteners will be routed to a central compressor facility, and then be routed to the wells via high-pressure rated NACE-compliant lines and temperature-compensated flow meters. Figure 3 summarizes the injection system design elements, and design details are provided in Section 3.3 below.

3.1 CALCULATED MAXIMUM INJECTION PRESSURE

The wells will be designed and constructed such that it will serve as the injection conduit for a stream of treated acid gas. The treated acid gas stream (TAG) will be of approximately the following composition:

- 85% CO_2
- 15% H_2S
- Trace Components of $C_1 - C_7$

The total volume of TAG to be injected under this scenario will be approximately 540 barrels per day for each million cubic feet at reservoir conditions. Pressure reduction valves will be incorporated to assure that maximum surface injection pressure allowed by NMOCD will not be exceeded.

The calculated maximum allowable injection pressure would be approximately 1,845 psig (depending on specific gravity of final TAG stream). We have used the following method approved by NMOCD to calculate the preliminary proposed maximum injection pressure. The final maximum permitted surface injection pressure should be based on the final specific gravity of the injection stream according to the following formula:

$IP_{max} = PG\ (D_{top})$ where: IP_{max} = maximum surface injection pressure (psig)
PG = pressure gradient of mixed injection fluid (psig/foot)
D_{top} = depth at top of perforated interval of injection zone (feet)

and $PG = 0.2 + 0.433\ (1.04 - SG_{tag})$ where:

SG_{tag} = specific gravity of treated acid gas (pressure and temperature dependent; calculated as the average density in the tubing, using surface conditions of 100°F and 1,200 psig, and bottom hole conditions of 125°F and 2,000 psig; see Table 1 for details)

For the maximum requested injection volume (6.8 MMSCF/Day) it is assumed that:

$$SG_{tag} = 0.602$$
$$D_{top} = 4{,}735 \text{ feet}$$

Therefore:

$$PG = 0.2 + 0.433\ (1.04 - 0.602) = 0.3896$$

$$IP_{max} = PG(D_{top}) = 0.3896 \times 4{,}735 = 1{,}845 \text{ psig}$$

Based on the performance of the existing injection well, it is anticipated that the average injection pressure would not exceed 1500 psig. Based on the above calculations, Stakeholder is requesting approval of a maximum injection pressure to be 1,845 psig at the surface.

3.2 INJECTION VOLUME CALCULATIONS

Review of available log data and other geological information indicates that there is approximately 75 feet of reservoir rock in the proposed injection zone with an average porosity of 15.5 percent or more. Incorporating the calculated residual water (Sw) of 0.35, this yields a net available porosity of 7.6 feet.

Table 1 below summarizes the calculations used to determine the radius of injection after 30 years of operating at an average rate of 3.4 MMSCFD, and Table 2 summarizes the calculations used to determine the radius of injection after 30 years of operating at an average rate of 6.8 MMSCFD.

At 3.4 MMSCFD per well after 30 years the TAG plume would occupy approximately 345 acres per well, and have a radius of 2,187 feet (0.41 miles) for each well. At the calculated 100% safety factor of 6.8 MMSCFD the injection plume is calculated to cover approximately 690 acres per well, with a radius of 3,093 feet (0.59 miles) per each well.

Since the calculated radii of both the 3.4 MMSCFD plumes (0.41 miles from each well) and the 6.8 MMSCFD plumes (0.59 miles from each) overlap (well spacing is 0.39 miles), the areas of the actual combined plumes will be larger than the single-well radii. Figure 4 shows these corrected plumes, based on total areas of 690 acres total, and 1,380 acres. The 690 acre plume would migrate a maximum distance of approximately 2,500 feet (0.47 miles) from either well, and the 1,380 acre plume would migrate approximately 3,700 feet (0.70 miles).

Table 1: Calculated Injection Area and Radii at 3.4 MMSCFD per Well

PROPOSED INJECTION STREAM CHARACTERISTICS

TAG	H_2S	CO_2	H_2S	CO_2	TAG
Gas vol MMSCFD	conc. mol %	conc. mol %	inject rate lb/day	inject rate lb/day	inject rate lb/day
3.4	15	85	48411	354246	402656

CONDITIONS AT WELL HEAD

Well Head Conditions		TAG							
Temp F	Pressure psi	Gas vol MMSCFD	Comp CO_2:H_2S	Inject Rate lb/day	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
100	1200	3.4	85:15	402656	505.00	0.51	4.22	12766	2274

CONDITIONS AT BOTTOM OF WELL

Injection Zone Conditions					TAG				
Temp F	Pressure[3] psi	$Depth_{top}$ ft	$Depth_{bottom}$ ft	Thickness[4] ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
125	2420	4735	4810	75.00	699.00	0.70	5.84	9223	1643

CONDITIONS IN RESERVOIR AT EQUILIBRIUM

Injection Reservoir Conditions					TAG				
Temp[5] F	Pressure[3] psi	Ave. Porosity[6] %	Swr	Porosity ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
125	2000	15.5	0.35	7.6	622.00	0.62	5.19	10365	1846

CONSTANTS

	SCF/mol	
Molar volume at STD	0.7915	
	g/mol	lb/mol
Molar weight of H_2S	34.0809	0.0751
Molar weight of CO_2	44.0096	0.0970
Molar weight of H_2O	18.015	0.0397

CALCULATION OF MAXIMUM INJECTION PRESSURE LIMITATION

SG_{TAG}	0.602
$PG = 0.2 + 0.433\,(1.04\text{-}SG_{TAG})$	0.390 psi/ft
$IP_{max} = PG * Depth$	1845 psi

Where: SG_{TAG} is specific gravity of TAG; PG is calculated pressure gradient; and IP_{max} is calculated maximum injection pressure.

[1] Density calculated using AQUAlibrium software
[2] Specific gravity calculated assuming a constant density for water
[3] PP is taken from well tests of Linam AGI #1
[4] Thickness is the net thinckness of the perforated intervals
[5] Reservoir temp. is extrapolated from bottomhole temp. measured in logs
[6] Porosity is estimated using geophysical logs from nearby wells

CALCULATION OF 30 YEAR AREA OF INJECTION

Cubic Feet/day (5.6146 ft^3/bbl)	10365 ft^3/day
Cubic Feet/30 years	113570980 ft^3/30 years
Area = V/Net Porosity (ft)	15030072 ft^2/30 years
Area = V/Net Porosity (ft) (43560 ft^2/acı	345.0 acres/30 years
Radius =	2187 ft
Radius =	0.41 miles

Table 2: Calculated Injection Area and Radii at 6.8 MMSCFD per Well (100% Safety Factor)

PROPOSED INJECTION STREAM CHARACTERISTICS

TAG	H_2S	CO_2	H_2S	CO_2	TAG
Gas vol MMSCFD	conc. mol %	conc. mol %	inject rate lb/day	inject rate lb/day	inject rate lb/day
6.8	15	85	96821	708491	805312

CONDITIONS AT WELL HEAD

Well Head Conditions		TAG							
Temp F	Pressure psi	Gas vol MMSCFD	Comp CO_2:H_2S	Inject Rate lb/day	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
100	1200	6.8	85:15	805312	505.00	0.51	4.22	25532	4547

CONDITIONS AT BOTTOM OF WELL

Injection Zone Conditions					TAG				
Temp F	Pressure[3] psi	$Depth_{top}$ ft	$Depth_{bottom}$ ft	Thickness[4] ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
125	2420	4735	4810	75.00	699.00	0.70	5.84	18446	3285

CONDITIONS IN RESERVOIR AT EQUILIBRIUM

Injection Reservoir Conditions					TAG				
Temp[5] F	Pressure[3] psi	Ave. Porosity[6] %	Swr	Porosity ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
125	2000	15.5	0.35	7.6	622.00	0.62	5.19	20729	3692

CONSTANTS

	SCF/mol	
Molar volume at STD	0.7915	
	g/mol	lb/mol
Molar weight of H_2S	34.0809	0.0751
Molar weight of CO_2	44.0096	0.0970
Molar weight of H_2O	18.015	0.0397

[1] Density calculated using AQUAlibrium software
[2] Specific gravity calculated assuming a constant density for water
[3] PP is taken from well tests of Linam AGI #1
[4] Thickness is the net thinckness of the perforated intervals
[5] Reservoir temp. is extrapolated from bottomhole temp. measured in logs
[6] Porosity is estimated using geophysical logs from nearby wells

CALCULATION OF MAXIMUM INJECTION PRESSURE LIMITATION

SG_{TAG}	0.602
$PG = 0.2 + 0.433\ (1.04 - SG_{TAG})$	0.390 psi/ft
$IP_{max} = PG * Depth$	1845 psi

Where: SG_{TAG} is specific gravity of TAG; PG is calculated pressure gradient; and IP_{max} is calculated maximum injection pressure.

CALCULATION OF 30 YEAR AREA OF INJECTION

Cubic Feet/day (5.6146 ft^3/bbl)	20729 ft^3/day
Cubic Feet/30 years	227141961 ft^3/30 years
Area = V/Net Porosity (ft)	30060144 ft^2/30 years
Area = V/Net Porosity (ft) (43560 ft^2/ac)	690.1 acres/30 years
Radius =	3093 ft
Radius =	0.59 miles

3.3 WELL DESIGN

The AGI compressor facilities and the wells are integrated components of the Stakeholder Gas Plant design. The schematic of the AGI facilities and tie-in to the Stakeholder Gas Plant are shown in Figure 3, and the preliminary well design for the new injection wells is shown on Figure 5.

Both wells will share the same basic design of three strings of the telescoping casing cemented to the surface and will include a subsurface safety valve on the production tubing to assure that fluid cannot flow back out of the well in the event of a failure of the injection equipment (Figure 5). In addition, the annular space between the production tubing and the well bore will be filled with an inert fluid (corrosion-inhibited diesel fuel) as a further safety measure which is consistent with injection well designs which have been previously approved by NMOCD for acid gas injection.

The wells will be advanced vertically to the anticipated approximate total depths of approximately 4,900 feet. The injection zones (approximately 4,760 to 4,835 feet) will be completed as a perforated, cased zone.

Design and material considerations include: Placement of Subsurface Safety Valve (SSSV) and the packer; triple casing through freshwater resources (Ogallala and Santa Rosa Formations – groundwater, Rustler – saline groundwater); characterization of the zone of injection; and a total depth (TD) ensuring identification of the reservoir. All casing strings will be cemented to the surface and the cement jobs will be verified by pressure testing. Radial 360° cement bond logs will be conducted for all casing strings as well.

A suitable drilling rig will be chosen for the job that will include an appropriate blowout preventer and choke manifold for any unforeseen pressures encountered. Visual inspections of cement returns to the surface will be noted in both the conductor and surface pipe casing jobs. Casing and cement integrity will be demonstrated by pressure-testing and 360-degree cement bond logging after each cement job.

The three casing strings shown in Figure 5 are summarized below:

1. The surface casing will extend to the base of the Dockum Formation, at approximately 600 feet depth, to protect fresh water in the Ogallala and Santa Rosa Formations. The borehole for the surface casing will be drilled with a 17 ½ -inch bit to a depth of approximately 600 feet (above the uppermost salt beds), and 13 3/8-inch, 61 ppf, J-55, BTC casing will be installed and cemented to the surface.

2. The intermediate casing will isolate the Salado salt beds, as well as any production zones above the Yates Formation. It will be drilled with a 12 ¼ -inch bit to a depth of approximately 3,340 feet and will be constructed with of 9 5/8-inch casing, using 40.0 ppf, N-80, STC. The casing will be cemented to the surface in two stages with Class C cement.

3. The production casing will be emplaced in a 8 ¾ inch borehole and will be constructed with three segments of casing. The upper segment will be composed of 7-inch, 29.0 ppf, P-110 casing, to a depth of approximately 4,440 feet. The second segment (4,440 to 4,740 feet) will include a 300-foot section of 7-inch 29.0 to 32.0 ppf V-110 Vallourec Corrosive Resistant Alloy (CRA) or equivalent material. This segment is to protect the packer and the adjacent cap rock zones from acid gases. The third segment will run from 4,740 feet to total depth of 4,900 feet and will be composed of the same 7-inch, 29.0 ppf, P-110 casing as was used in the first segment. This final casing string will be perforated at selected depths, based on geophysical logs and mudlog data. The basal portion of the production string up to approximately 4,000 feet will be cemented with

corrosion-resistant cement. The remaining casing will be cemented to the surface with Class H cement.

The proposed open hole logging suite for the TD run consists of a Dual Induction, Density-Neutron-Gamma Ray, Porosity and Formation Micro Imager (FMI) log in the injection zone.

Once the cement has set up, the tubing adaptor for the wellhead will be welded on the wellhead and the rig will be released. A casing integrity test (pressure test) will be performed to test the casing just prior to releasing the rig. After a successful test and the drilling rig released, a work-over rig will be mobilized to the location and a cement bond log will be run to ascertain the quality of the cement bond of the production casing. It is important that a good bond be established around the injection interval as well as below the CRA joint to minimize any chances that acid gases mixed with formation water do not travel up the outside of the casing and negatively impact the integrity of the casing job.

Once the integrity of the cement job has been determined a temporary string of removable packer and tubing will be run, and injection tests (step tests) will be performed to determine the final injection pressures and volumes.

Once the reservoir has been tested, the final tubing string will be emplaced. The tubing completion schedule is:

1. 3 ½ - inch 9.3 ppf L-80 VAM TOP from 0 to 250 feet
2. Subsurface Safety Valve Assembly, 250 to 280 feet
3. 3 ½ - inch 9.3 ppf L-80 VAM TOP from 280 to 4,440 feet
4. 3 ½ - inch 9.3 ppf Incoloy or equivalent CRA material VAM TOP from 4,400 to the pacler at ~4,740 feet
5. Bottom hole pressure/temperature sub (Halliburton ROC gauge)
6. 7 inch 26 32# BWD Incoloy 925 Permanent Packer at ~4,650 feet

Permanent, continuous-recording sensors will be incorporated into a sub located immediately above the packer assembly and appropriate connections will be run through the annulus and out of the well head. These sensors will provide real-time temperature and pressure in the reservoir. Data will be transmitted to the plant's control room for observation, analysis, and recording. Section 3.4 below addresses how that data will be used and supplemented in the event of downhole sensor failure.

The SSSV will be run into the well at a depth of approximately 250 feet. A ¼-inch stainless steel line will connect the SSSV to a hydraulic panel at the surface.

The National Association of Corrosion Engineers (NACE) issues guidelines for metals exposed to various corrosive gases like the ones in this well. For a H_2S/CO_2 stream of acid gas that is de-watered at the surface through successive stages of compression, downhole components such as the SSSV and packer need to be constructed of or cladded with Inconel 925 or equivalent. The CRA joints will be constructed of a similar alloy from a manufacturer such as Sumitomo. The gates, bonnets, and valve stems within the Christmas tree will also be nickel coated or cladded with similar materials.

The rest of the Christmas tree will be made of standard carbon steel components and outfitted with annular pressure gauges that report operating pressure conditions in real time to a gas control center located remotely from the wellhead. In the case of abnormal pressures or any other situation requiring immediate action, the acid gas injection process can be stopped at the compressor and the wellhead. An emergency shutdown (ESD) valve and a Fisher control valve control compressor backpressure, and both are pneumatically operated on the well head. The SSSV provides a redundant safety feature to shut in the well in case the wing valve does not close properly. After the AGI wells are drilled and tested to assure that it will be able to accept the volume of injection fluid (without using acid gas), it will be completed with the approved injection equipment for the acid gas stream.

3.4 RESERVOIR TESTING AND PRESSURE MONITORING

The Stakeholder AGI #1 and AGI #2 will be equipped with bottom hole pressure and temperature monitoring equipment. This equipment is designed to provide real-time monitoring of reservoir conditions as it is installed immediately above the packer. While this equipment is useful in gathering data that will ultimately be used to evaluate reservoir and well performance, it is only a portion of the overall data collection and analysis program to evaluate the reservoir over time and to compare the predicted reservoir performance discussed above in Section 3.2 with actual performance at any future reporting period.

The collection and analysis of injection and annular pressure data has a two-fold purpose. The primary purpose being to provide an early warning of any mechanical well issues which may arise and the second purpose is to provide data for reservoir performance evaluation. While the initial purpose of monitoring the mechanical integrity of the well only requires the surface injection pressure, temperature, rate, and annular pressure monitoring, the bottom hole data provides the ability to analyze the performance of the reservoir. Surface pressure/temperature/annular pressure monitoring equipment has extremely high reliability. In contrast, our initial experience with bottom hole pressure/temperature monitoring equipment has shown that this equipment is more complex and suffers from periodic data collection and transmission issues.

While Stakeholder will use its best efforts to improve performance and reliability, we have developed a process to assure necessary data are collected in the event of bottom hole sensor failures. The simultaneous collection of the surface and bottom hole data allows us develop empirical relationships with actual observed data that, in conjunction with the use of established models (such as AQUAlibrium™ or equivalent) will allow us to fill in gaps when bottom hole data loss occurs due to sensor or data transmission failures. This approach will allow us to provide NMOCD with reliable monitoring data and interpretations and provides the basis for the reservoir evaluation which will be performed periodically during the lifetime of the well.

Below is a summary of the overall data collection and analysis program proposed for these wells and reservoir.

1. Install work string and packer, swab and collect formation fluid samples; verify lack of economical hydrocarbons.
2. Obtain initial bottom hole pressure and temperature after drilling (during logging).
3. Perform detailed SRT and 10 day falloff test to provide baseline reservoir data prior to injection.
4. Monitor surface parameters (injection pressure, temperature and rate, and annular pressure) to provide early warning system for any potential mechanical issues in the well.
5. Monitor bottom hole pressure/temperature with a device to provide real time reservoir condition data for analysis of reservoir performance.
6. Use bottom hole reservoir and surface pressure/temperature data to develop well-specific empirical relationship between observed surface and bottom hole data.
7. Use TAG/wellbore models to predict bottom hole P/T conditions based on surface data and test with empirical relationships observed in #5 above to calibrate models.
8. Use surface data along with tools in #5 and #6 above to fill in missing bottom hole data when data drops or sensor failure occurs.

4.0 REGIONAL AND LOCAL GEOLOGY AND HYDROGEOLOGY

4.1 GENERAL GEOLOGIC SETTING/SURFICIAL GEOLOGY

The Stakeholder Gas Plant is located in Section 21, T16S, R35E approximately 9 miles southwest of Lovington in Lea County, New Mexico (Figure 1). The Plant is located within a physiographic area known as the Llano Estacado (High Plains) approximately 22 miles east of the Mescalero Ridge and Pecos River basin (Nicholson & Clebsch, 1961). This area is relatively flat with a gentle east-southeast slope. Small sand dunes and shallow depressions are the only significant relief features on the Llano Estacado, and marred only by slight undulations and covered with short prairie grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the Plant. The Plant site is underlain by the Miocene-Pliocene Ogallala Formation overlying Triassic redbeds of the Dockum Group, both of which are local sources of groundwater. The Ogallala Formation is composed of alluvial and eolian deposits, and petrocalcic soils (i.e. caliche) that make this topographically high area relatively resistant to erosion. The thick sequences of Permian rocks that underlie these deposits are generally described below.

4.2 BEDROCK GEOLOGY

Figure 6 shows the structural setting of the proposed Stakeholder plant and AGI wells, and Figure 7 is a generalized stratigraphic column showing the Permian formations that underlie the Plant site. The proposed plant and well are located in the Delaware Basin west of the northwestern margin of the Central Basin Platform. The Delaware basin is a structural low and the Central Basin Platform is a structural high, and both are components of the larger encompassing Permian Basin, which covers a large area of southeastern New Mexico and west Texas. The Permian Basin lies within the area of the larger, ancestral (pre-Mississippian) Tabosa Basin, which covered an area that included the entire present-day Permian Basin area and beyond. The Tabosa Basin was a shallow sub-tropical basin throughout the period between the Ordovician and early Mississippian (Osagean).

There are approximately 1,600 feet of Triassic rocks, 10,000 feet of Permian rocks, and up to 5,000 feet of older Paleozoic rocks in the region. The Triassic rocks at this location include the Dockum Group, a late Triassic deposit of red mixed clastics (i.e. red beds) sourced from older Paleozoic rocks. The Permian rocks of interest at this location include the Ochoa, Rustler, Salado, Tansill, Yates, Seven Rivers, Queen, Grayburg, and San Andres, covering Late-Middle Permian time, respectively. The upper Late Permian sections (Seven Rivers-Queen interval) are anhydrite-rich. These anhydritic carbonates are generally tight and provide excellent seals between porous zones. The Seven Rivers-Queen interval in this area carries a relatively lower percentage of anhydrite, not as discrete beds, but as secondary diagenetic fill of vugs and voids.

The lower Middle Permian section (Grayburg-San Andres interval) contains sandy siltstones, limestone, dolomite, and sandstones and is loaded with secondary anhydrite in thick bedded dolomites, and as such, has the lowest overall porosity budget in the area. However, the Premier Sand, a basal member of the Grayburg Formation that was deposited as series of transgressive shallow submarine bars during the Middle Permian, is a relatively high porosity zone with indications of good permeability. The Premier Sand sits on top of the upper San Andres, and is the most universally present and porous unit in the shallow Permian section.

Production is active in the two-mile area of the proposed project, but is limited to deeper zones, including the Abo (Permian) down to the Mississippian. This production precludes the use of deeper zones for injection in this area (Figure 7).

There have been no commercially significant deposits of oil or gas found in the Premier Sand rocks (the proposed injection zone), in the vicinity of the well. Adjacent wells have shown that this formation is "wet", and there is no current or foreseeable production at these depths within the one-half mile radius of review. In fact, this zone has been used as a produced-water disposal zone in this area.

4.3 LITHOLOGIC AND RESERVOIR CHARACTERISTICS OF THE PREMIER SAND

The proposed primary injection interval includes the Premier Sand, a basal member of the Grayburg Formation. Based on the geologic analyses of the subsurface, we recommend acid gas injection and H_2S/CO_2 sequestration in the Premier Sand.

Figures 8 and 9 provide a cross-section showing the stratigraphic context and relative thickness of the Premier Sand in the immediate area of the proposed plant and wells. Figure 10 is a more detailed log segment form a well adjacent to the proposed project, and shows good evidence for porosity in the range of 15% in this interval.

Figure 11 shows an interpreted contour map of sand thickness in the Premier Sand interval. This shows that there is as much as 80 feet of available sand in the selected AGI well locations.

4.4 INJECTIVITY OF THE PREMIER SAND INTERVAL

No direct measurements have been made of the injection zone porosity or permeability. After completion, a comprehensive suite of reservoir tests will be conducted (see Section 3.4 above) to better characterize the zone.

4.5 FORMATION FLUID CHEMISTRY

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v2.2n (2/16/2016) identified 38 wells with analyses from drill stem test fluids collected from the Grayburg and San Andres Formations, in wells within approximately 12 miles of the proposed Stakeholder AGI #1 and AGI #2.

These analyses showed Total Dissolved Solids ranging from 13,368 to 273,964 milligrams per liter (mg/l) with an average of 156,155 mg/l. The specific gravity ranged from 1.01 to 1.19 with an average of 1.11. One pH measurement was taken from one well within the area of review, and had pH of 7.5. No other constituents were measured or presented in this report for the wells surveyed. An attempt will be made to collect formation fluids within the injection interval.

4.6 GROUNDWATER HYDROLOGY IN THE VICINITY OF THE PROPOSED INJECTION WELL

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are six water wells within one mile of the proposed Stakeholder AGI #1 and AGI #2; the closest water well is located 0.39 miles away (Figure 12; Table 3). All wells within the one mile radius are shallow, collecting water from about 60 to 280 feet depth, in the alluvium and/or in the Triassic redbeds. Two of the closest wells were permitted to drill for irrigation purposes, but the permits were cancelled. Three wells within one mile are permitted for prospecting or the development of natural resources. Only one well is used for domestic and livestock watering. The shallow freshwater aquifer these wells collect from is protected by the surface and intermediate casing in the proposed Stakeholder AGI #1 well, which extend to 600 feet and 3,340 feet, respectively.

The area surrounding the proposed injection well is arid and there are no bodies of surface water within a five mile radius.

Table 3: Water Wells Identified by the New Mexico State Engineer's Files within One Mile of the Proposed Stakeholder AGI #1 and AGI #2 Wells

POD Number	OWNER	Use	UTME	UTMN	Well Depth (ft)	Water Depth (ft)
L 00079	WILLARD EIDSON	Irrigation/*cancelled*	642560	3641679	N/A	N/A
L 01993	MILLARD EIDSON	Irrigation/*cancelled*	642353	3641880	N/A	N/A
L 08230	DINERO OPERATING COMPANY	Prospecting for natural resources	642749	3642287	157	60
L 12470 POD1	EIDSON RANCH	Domestic/livestock watering	642235	3641845	195	60
L 08141	FORSTER DRILLING CO.	Prospecting for natural resources	643981	3640689	125	60
L 04974	CACTUS DRILLING COMPANY	Prospecting for natural resources	643139	3643097	330	280

Note: UTM coordinates are calculated by the State Engineer from PLSS locations and may be approximate.

5.0 OIL AND GAS WELLS IN THE STAKEHOLDER AGI #1 and AGI #2 AREA OF REVIEW

Within the combined two miles of the proposed Stakeholder AGI #1 and AGI #2 there are 57reported wells, of which 19 are active and 38 have been plugged and abandoned. These wells are tabulated, and shown on a map, in Appendix A.

In the combined one mile radii of the proposed Stakeholder AGI #1 and AGI #2 there are 12 reported wells of which 4 are currently active and 8 are plugged and abandoned. These wells are shown in Figure 4 and their details are summarized in Table 4 below.

TABLE 4: Wells Penetrating Injection Zone within One Mile of the Proposed Stakeholder AGI #1 and AGI #2

API	OPERATOR	WELL NAME	SPUD DATE	PLUG DATE	TVD DEPTH	STATUS	DISTANCE FROM AGI #1 (miles)	DISTANCE FROM AGI #2 (miles)
3002526270	BP AMERICA PRODUCTION	STATE HC 001	5-Apr-79	27-Aug-79	13001	Plugged	0.26	0.25
3002535010	LEGACY RESERVES OPERATING, LP	ROCKY STATE GH COM 002	28-Apr-00	NA	12854	Active	0.66	0.35
3002526154	V-F PETROLEUM INC	STATE GH 001	5-Dec-78	NA	12900	Active	0.51	0.36
3002536334	EOG RESOURCES INC	VIPER 21 STATE 001	2-Aug-03	7-Sep-03	11500	Plugged	0.73	0.53
3002535544	LEGACY RESERVES OPERATING, LP	PALOMINO MIDGE 22 STATE COM 001	23-May-01	NA	13570	Active	0.79	0.55
3002526433	CARR WELL SERVICE INC	EIDSON COM 001	5-Sep-79	31-Jan-85	13050	Plugged	0.58	0.75
3002532738	NEARBURG PRODUCING CO	EIDSON 29 STATE COM 001	20-Dec-94	6-Feb-95	12993	Plugged	0.67	1.06
3002526694	DINERO OPERATING CO	EIDSON 001	16-Mar-80	1-Feb-82	13050	Plugged	0.68	0.80
3002535666	LEGACY RESERVES OPERATING, LP	MUSTANG MIDGE 28 001	20-Sep-01		13150	Plugged	0.74	0.79
3002502806	MAGNOLIA PETROLEUM CO	SCHARBAUER EIDSON 001	14-Jul-36	31-Dec-36	5300	Plugged	0.75	1.12
3002536165	MEWBOURNE OIL CO	ROCKY 16 STATE 001	11-Mar-03	NA	12975	Active	1.01	0.87
3002535172	DAVID H ARRINGTON OIL & GAS INC	LORD BALTIMORE 20 STATE 001	8-Mar-01	7-May-14	13100	Plugged	1.06	1.35

Appendix A also provides completion and/or plugging diagrams for these 12 wells. Their configurations are documented in detail in Table A2.

Three wells are located within the calculated 30-year injection plume (690 acres), assuming that 3.4 MMSCFD of TAG will be approximately equally distributed between both proposed wells. The wells are:

- State HC 001 (API # 3002526270) is located 0.25 miles from proposed AGI #2. This well was plugged and abandoned in August 1979. The original intermediate casing was set and cemented into the San Andres beneath the Premier Sand, and the TOC was at ~1,575 feet, well above the Premier. This casing remained in the well during plugging. This configuration provides excellent isolation for the Premier Sand.

- Rocky State GH Com 002 (API # 3002535010) is located 0.35 miles from the proposed AGI #2. This well was spudded in April 2000 and is an active producer in the Atoka/Shoebar zone. The intermediate casing was set and cemented into the San Andres beneath the Premier Sand, and cement was circulated to the surface. This configuration provides excellent isolation for the Premier Sand.
- State GH 001(API # 3002526154) is located 0.36 miles from the proposed AGI #2. This well was spudded in December 1978 and is an active producer in the Morrow zone. The intermediate casing was set and cemented above the Premier Sand, and the TOC was at ~600 feet. The production casing was cemented to a TOC of ~2,290 feet, well above the Premier Sand. This configuration provides excellent isolation for the Premier Sand.

Five wells are located within the 100% safety zone calculated for the 30-year injection plume (1,380 acres), assuming that 6.8 MMSCFD of TAG will be approximately equally distributed between both proposed wells. The wells are:

- Viper 21 State 001 (API # 3002536334) is located 0.53 miles from the proposed AGI #2. This well was plugged and abandoned in September 2003. The original intermediate casing was set and cemented into the San Andres beneath the Premier Sand, and cemented with 1,480 sacks, more than adequate to reach above the Premier. This casing remained in the well during plugging. This configuration provides excellent isolation for the Premier Sand.
- Palomino Midge 22 State Com 001 (API # 3002535544) is located 0.55 miles from the proposed AGI #2. This well was spudded in May 2001 and is an active producer in the Atoka/Shoebar zone. The intermediate casing was set and cemented into the San Andres beneath the Premier Sand, cemented with 1,250 sacks, more than adequate to reach above the Premier. This configuration provides excellent isolation for the Premier Sand.
- Eidson Com 001 (API # 3002526433) is located 0.58 miles from the proposed AGI #1. The well was plugged and abandoned in January 1989. The intermediate casing was originally set at 4,600 feet, above the Premier Sand, and was cemented to the surface. The production casing was cemented with a TOC at ~8,990 feet. During plugging cement plugs adjacent to the Premier Sand were set at 6,296, and 4,630 feet and heavy mud was retained between the plugs. This provides adequate protection for the Premier Sand.
- Eidson 29 State Com 001 (API # 3002532738) is located 0.67 miles from the proposed AGI #1. The intermediate casing was set and cemented into the San Andres beneath the Premier Sand, and cemented to the surface with 1,220 sacks, fully sealing the Premier. The intermediate casing and cement were retained when the well was plugged and abandoned in February 1995. This configuration provides excellent isolation for the Premier Sand.
- Eidson 001(API # 3002536334) is located 0.68 miles from the proposed AGI #1. The intermediate casing was originally set at 4,456 feet, above the Premier Sand, and was cemented to the surface with 2,520 sacks. The production casing was cemented with 1,200 sacks with no reported TOC. During plugging in February 1982 cement plugs adjacent to the Premier Sand were set at 6,600, and 4,500 feet and heavy mud was retained between the plugs. This provides adequate protection for the Premier Sand.

Four wells are outside the 100% safety zone, but within one mile of one or both of the proposed AG wells. These include:

- Mustang Midge 28 001 (API # 3002535666) is located 0.74 miles from the proposed AGI #1. The intermediate casing was set and cemented into the San Andres beneath the Premier Sand, and cemented to the surface with 1,200 sacks, fully sealing the Premier. The intermediate casing and cement were retained when the well was plugged and abandoned in January 2015. This configuration provides excellent isolation for the Premier Sand.
- Scharbauer Eidson 001 (API # 30002806) is located 0.75 miles from the proposed AGI #1. This well was spudded in July of 1936 and plugged and abandoned in December of 1936. The well was advanced to a total depth of 5,300 feet and determined to be a dry hole. Intermediate casing was set at 2,156 with no reported TOC. During plugging the intermediate casing was cut and pulled at ~1,000 feet, and the entire borehole filled with 14 pound/gallon mud. This plugging technique does not meet modern standards, but this well is located well outside the calculated 100% safety zone.
- Rocky 16 State 001 (API # 3002536165) is located 0.87 miles from the proposed AGI #2. The well was spudded in March 2003 and is an active Townsend/Mississippian producer. The intermediate casing was set above the Premier Sand at 4,322 feet and cemented to the surface with 1,800 sacks. The production casing was cemented with 825 sacks and the reported TOC was ~9,640 feet. The annulus penetrating the Premier Sand is currently filled with heavy mud. This well is located well outside the calculated 100% safety zone.
- Lord Baltimore 20 State 001 (API # 3002535172) is located 1.06 miles from the proposed AGI #1. The intermediate casing was set above the Premier Sand at 4,765 feet and cemented to the surface with 1,690 sacks. The production casing was cemented with 790 sacks to a reported TOC of 7,430 feet. During plugging in May 2014 cement plugs adjacent to the Premier Sand were set at 7,325, 5,112, and 4,586 feet and heavy mud was retained between the plugs. This provides adequate protection for the Premier Sand, and this well is located well outside the calculated 100% safety zone.

The evaluation of the conditions of these 12 wells shows that the injected TAG will be properly contained.

6.0 IDENTIFICATION AND REQUIRED NOTIFICATION OF OPERATORS, SUBSURFACE LESSEES, AND SURFACE OWNERS WITHIN THE AREA OF REVIEW

Geolex has reviewed the land status and operators within one mile of the proposed Stakeholder AGI #1 and AGI #2. Active well operators are tabulated below and the remainder of the potentially affected parties are detailed in Appendix B.

TABLE 5: Operators with Active Wells within One Mile of the Proposed Stakeholder AGI #1 and AGI #2

OPERATOR	ADDRESS	CITY	ZIP	ACTIVE WELLS	PLUGGED WELLS
Legacy Reserves Operating, LP	303 W Wall, Suite 1400 Midland, TX 79701	Midland	79701	2	1
Mewbourne Oil Company	PO Box 7698 Tyler, TX 75711	Tyler	75711	1	0
V-F Petroleum	500 W Texas Ave Midland, TX 79701	Midland	79701	1	0

Appendix C contains copies of registered mail receipts, individual letter, and the newspaper affidavit of publication.

7.0 AFFIRMATIVE STATEMENT OF LACK OF HYDRAULIC CONNECTION BETWEEN PROPOSED INJECTION ZONE AND KNOWN SOURCES OF DRINKING WATER

As part of the work performed to support this application, a detailed investigation of the structure, stratigraphy and hydrogeology of the area surrounding the proposed Stakeholder AGI #1 well has been performed. The investigation included the analysis of available geologic data and hydrogeologic data from wells and literature identified in Sections 3, 4 and 5 above including related appendices. Based on this investigation and analysis of these data, it is clear that there are no open fractures, faults or other structures which could potentially result in the communication of fluids between the proposed injection zone with any known sources of drinking water or oil or gas production in the vicinity as described above in Sections 4 and 5 of this application.

8.0 REFERENCES

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FIGURES