dcp Midstream.

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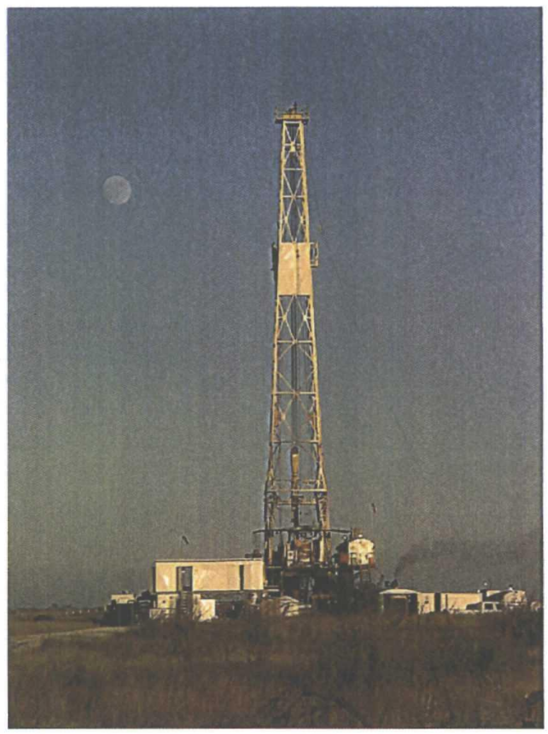
Final End of Well Report

DCP Midstream LLC
Linam AGI #1
API # 3002538576
1980'FSL & 1980' FWL
Section 30, T18S, R37E
Lea County, New Mexico



September 30, 2011

Prepared For:
DCP Midstream LLC
370 17th Street, Suite 2500
Denver, Colorado 80202

Prepared By:
Geolex, Inc.
500 Marquette Avenue, NE, Suite 1350
Albuquerque, New Mexico 87102
(505)-842-8000

BEFORE THE OIL CONSERVATION
COMMISSION
Santa Fe, New Mexico
Exhibit No. 5
Submitted by:
DCP MIDSTREAM, LP
Hearing Date: December 20, 2012

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DCP MIDSTREAM LLC
LINAM AGI #1

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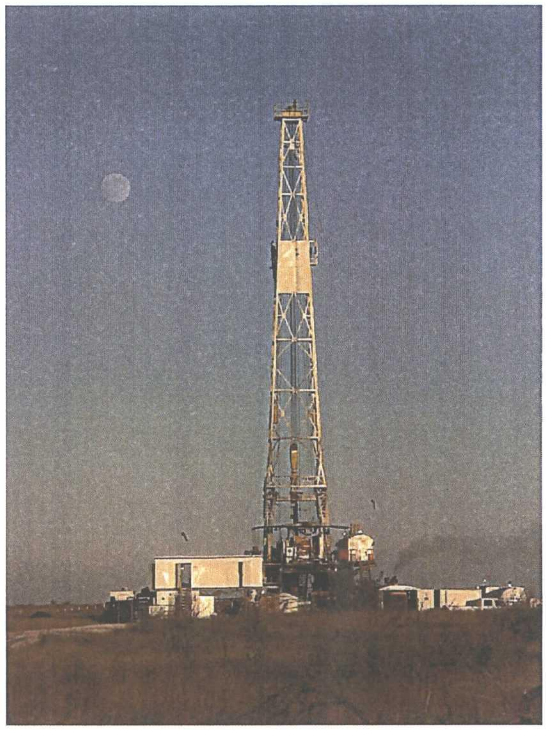

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1.0 EXECUTIVE SUMMARY AND WORK PERFORMED

On September 12, 2005, Geolex Inc.® (Geolex), on behalf of Duke Energy Field Services (now DCP Midstream, LP), submitted a C-108 Application for Authorization to Inject for an acid gas injection (AGI) well, to be located near the DCP Midstream's Linam Gas Plant near Hobbs, New Mexico (Figure 1). The purpose of the AGI was to replace the existing sulfur reduction unit (SRU) used to reduce elemental sulfur from the treated acid gasses (TAG) from the sweetener units. The SRU was aging, inefficient, and caused chronic emission problems.

On February 9, 2006, a hearing was held by the New Mexico Oil Conservation Division (NMOCD) to review the C-108 application. On May 5, 2006, NMOCD approved the application under Order R-12546, allowing DCP Midstream (DCP) to inject treated acid gasses (TAG) into the lower Bone Springs at pressures not to exceed 2,644 psi. The term of that Order was extended on April 2, 2006, until January 5, 2009, due to logistical and permitting issues.

The original Order R-12546 of May 5, 2006, required that DCP receive an approved Discharge Plan before commencing injection. While the Discharge Plan was being prepared and reviewed, the problems with the SRU became acute, and DCP petitioned and received Order 12546-D on November 20, 2009, temporarily staying the Discharge Plan requirement and allowing DCP to begin injection. This Order, however, capped the injection rate at 4.0 million standard cubic feet per day (MMSCFD) and a pressure of 1,800 psi. Subsequent changes in NMOCD policy eliminated the requirement for a Discharge Plan, and, after a NMOCD public hearing held on July 14, 2011, on July 28, 2011, issued Order 12546-I rescinding the formerly required Discharge Plan, lifting the caps on volume and restoring the original injection pressure of 2,644 psi.

The injection well and compressor facility is located approximately one mile north of the Linam Gas Plant. This location was selected after careful review of the local geology. The plant is located on the northern end of the Central Platform, a buried structural high in the Permian Basin. In this area, the Permian Bone Springs consists of carbonate debris fans that flowed down slope from the northern edge of the Central Platform. Seismic data showed that these debris fans were very thin under the Linam Plant, but thicken abruptly north of the Platform edge to the immediate north. By selecting a location one mile north of the plant, a far more favorable reservoir could be encountered by the well.

In order to transfer the TAG from the plant to the well, a low-pressure pipeline was constructed from the plant to the well site (Figure 2). Here, a compressor plant has been constructed to raise the TAG pressure from the line pressure of approximately 80 psi to as high as 2,600 psi at the well head. A comprehensive Hydrogen Sulfide Contingency Plan (Rule 11), which encompasses the Gas Plant, the pipeline, the compressor facility and the well head (Appendix N), was submitted to NMOCD and approved in November 2009, prior to commencement of injection operations.

On October 20, 2007, Tyler Well Service moved in and rigged up their Rig #2. At 0400 on October 21, 2007, the Linam AGI #1 well (API # 3002538576) was spudded 1,980 feet FSL and 1,980 feet FWL in Unit K of Section 30, Township 18 South, range 37 East in Lea County, New Mexico. A total depth of 9,213 feet in the Permian Wolfcamp Series, directly beneath the Bone Springs, was reached on November 16, 2007, and after logging and casing, the rig was released on November 20, 2007.

Between December 12 and December 23, 2007, the well was perforated, acidized and swabbed for cleaning and initial testing The well was then shut in for a 7-day pressure test. These tests indicated excellent injectivity in the reservoir.

On January 2, 2008, the well was re-entered for a step test. Testing began on January 3, and involved injection steps from 1 to 9 barrels per minute, with 30-minute steps. Subsequent analyses (Figure 10 and Appendix J) showed no parting or fracture behavior at or above the approved maximum pressure (2,644 psi).

On January 19, 2008, following additional testing, a mechanical integrity test (MIT) was conducted, testing the 7 inch casing at 600 psi for 30 minutes. After the successful test was completed, a drillable bridge plug was set at 8,650 feet, topped with 45 feet of cement. The well was secured and temporarily abandoned in anticipation of the installation, testing and operation of the topside compressor facility.

On July 20, 2009, DCP Midstream re-entered the well and drilled out the bridge plug and cement. A permanent packer was set at 8,750 feet, and 3 ½ inch, 9.3 pound/foot tubing was installed, along with a subsurface safety valve (SSV) at 259 feet. Diesel fuel was installed to fill the annulus between the production casing and the tubing. Approximately 15,000 gallons of 15% HCl was pumped down the tubing to reconfirm the injection capacity. The remote panel for the SSV was installed and tested, and the well head was secured.

After final testing of the topside compressor facilities, initial injection began in December 2009. Since then, through June 2011, the well has received 1,779,347 barrels of compressed TAG, or a daily average of 3,089 barrels per day. This rate has been achieved at an average wellhead pressure of 1,149 psi, well below the previous Order maximum of 1,800 psi.

This rate limit was subsequently lifted, and the pressure cap restored to the original 2,644 psi, in NMOCD Order No. 12546-I, issued on July 28, 2011.

The AGI system is designed to be safe and robust. All tubing and equipment in contact with the TAG is constructed of materials resistant to the corrosive properties of the gasses. The Christmas tree, designed and built by Wood Group, contains corrosion-resistant material in all surfaces contacting the TAG. From the wellhead, the TAG will be carried to the production packer via 3-½ inch L-80 tubing. The Schlumberger QL 7X4 production packer, set at 8,750 feet, is constructed from Incoloy 925 material.

The Linam #1 AGI well was originally designed for the purpose of safely injecting up to 4.6 million standard cubic feet (MMSCF) per day of treated acid gas (TAG) produced from the DCP Midstream Linam Gas Plant. The TAG stream consisted of approximately 72% carbon dioxide (CO_2), 28% hydrogen sulfide (H_2S) and traces of light hydrocarbons ($C_1 - C_7$). At well head pressures of 1,150 psi, this TAG will be compressed to approximately 1,862 barrels per day, equilibrated in the reservoir.

Changes in the field gas stream and plant operations have increased the daily production of TAG to 7.0 MMSCFD, and a change in the composition to 81.6% carbon dioxide (CO_2), 18.4% hydrogen sulfide (H_2S) and traces of light hydrocarbons ($C_1 - C_7$). At well head pressures of 1,150 psi, this TAG would be compressed to approximately 2,899 barrels per day, equilibrated in the reservoir.

At the original design rate of 4.6 MMSCFD, the calculated 30-year radius in injection would be approximately 0.38 miles, and fill an area of approximately 285 acres. At 7.0 MMSCFD, the radius would increase to 0.47 miles, and the area to 445 acres.

2.0 ORGANIZATION OF END OF WELL REPORT

This is a final well report describing the design, installation, completion and current status of the Linam AGI #1 acid gas injection well. This report is presented in the following categories:

- A history of the Linam AGI #1 project, including: a description of the Linam natural gas processing plant and the need for the AGI project; a summary of the project permitting history; a basic project design and anticipated disposal volumes; and a review of nearby wells and potential interactions (Section 3.0),
- A synopsis of the technical aspects of the Linam AGI #1 design, the drilling operations, and completion (Section 3.0),
- An evaluation of the local subsurface geology and the suitability of the Bone Springs Formation as an injection reservoir (Section 4.0), and
- A characterization of the reservoir and its response to injection, including an evaluation of the area that will be impacted by injection (Section 5.0).

In addition, this report includes the following supporting information:

- Appendix A: NMOCD Documents and Orders
- Appendix B: Well Bore Specifications
- Appendix C: Drilling Plan
- Appendix D: Drilling Reports
- Appendix E: Cement Program and CBLs
- Appendix F: Mud Program
- Appendix G: Coring and Core Analyses
- Appendix H: Open-Hole Geophysical Logs
- Appendix I: Completion Reports
- Appendix J: Reservoir Tests and Reservoir Calculations
- Appendix K: Formation Fluid Analyses
- Appendix L: Design Specifications for Subsurface Safety Valve, Panel and Operation Manual
- Appendix M: C-115 Injection Report Summaries
- Appendix N: H_2S Contingency Plan

3.0 PERMITTING, DESIGN DRILLING AND COMPLETION

Following initial discussions in August of 2003, Geolex was retained by DCP to evaluate the potential for an acid gas injection well for their natural gas plant, located east of Hobbs, New Mexico (Figure 1). Geolex collected, analyzed and evaluated the available geological information relevant to the area, and developed a feasibility study, presented in April 2005. The study identified the Permian Bone Springs Formation as the best injection target, and closely examined the two major options, drilling at the site, and drilling at a more geologically promising site approximately one mile north of the plant. More detailed options included:

1. Drilling a vertical well on the site, where geological data indicated that the Bone springs was relatively thin and was likely to have relatively low porosity,
2. Drilling a deviated well from the site to the more promising zone of the Bone Springs, one mile to the north,
3. Drilling the well at the north location, and building a new sweetening plant and compressor plant at the well site, eliminating the new pipeline under the highway, and
4. Drilling the well at an available location one mile north of the plant, building a low-pressure TAG pipeline beneath the intervening highway, and building a compressor facility by the well head.

Option 1 was rejected due the geological uncertainties, particularly with respect to the formation capacity for the anticipated volume of TAG to be injected over the life of the plant. Although Option 2 would reach the target and eliminate the pipeline, it was also rejected due to the cost and complexity of a deviated well. Option 3 was rejected, due to the costs and additional personnel required to build a large second facility away from the existing plant. This option would also require significant re-design and construction of existing field pipelines.

Option 4 was selected, based on the most favorable geological target and the best compromise in capital and operational costs. Following the selection of this option, Geolex began working with DCP to:

- Develop a detailed design and Authorization for Expenditures (AFE) for the proposed well,
- Research land issues regarding the well site and the proposed pipeline right-of-way, and
- Prepared, submitted and received approval for an Authorization to Inject (C-108) with the New Mexico Oil Conservation Division.

The successful accomplishment of these items is detailed in the sections below.

3.1 PLANT DESCRIPTION AND NEED FOR AGI

The DCP Linam Gas Plant collects and processes approximately 156 MMSCFD of field gas from fields in the adjacent Permian Basin. The field gas is treated to remove 4.85 MMSCFD (3 % total) of acid gases, of which H_2S comprises 0.89 MMSCFD (18% acid gases) and CO_2 accounts for 4.85 MMSCFD (82% acid gases).

After physical separation to remove the associated hydrocarbon condensate and produced water, the field gas is sent to an amine sweetener to remove the H_2S and CO_2. After a final dehydration process, the gas is sent to a cryogenic plant to remove useful liquefied gases such as butane and propane. The final natural gas stream is then delivered to pipelines for sale.

As originally designed and operated, the H_2S and CO_2 TAG stream was piped to a sulfur recovery unit (SRU) to reduce the H_2S to elemental sulfur, using the Claus process. The first stage of the Claus process involves oxidizing the H_2S to SO_2, using atmospheric oxygen for combustion. Due to the high percentage of CO_2 in the TAG stream (82%), a significant amount of otherwise-marketable natural gas must be burned with the TAG to maintain combustion.

In effect, the SRU acts as a bottleneck in the plant's operational capacity. Additional problems include the net costs of disposal of the waste sulfur (approximately 40 tons per day), carbon emissions to the atmosphere (approximately 300 tons per day of CO_2), operational costs, and problems with environmental compliance.

As the SRU at the Linam Plant neared its useful life, the economics and environmental benefits of an AGI greatly overweighed the costs of replacing the SRU with a similar unit.

3.2 PERMITTING HISTORY OF AGI WELL

The major milestones in the permitting, drilling and completion of the Linam AGI #1 are summarized in Table 1 below. The original application was approved in NMOCD Order R-12546 on March 5, 2006. Over the next 5 years, an additional 9 Orders were promulgated (Appendix A), and are summarized below.

- R-12546-A (June 5, 2006): Denial of a request for re-hearing by adjacent landowners
- R-12546-B (March 2, 2007): Extension of period to drill until May 5, 2008
- R-12546-C (October 31, 2008): Extension of period to drill until December 31, 2009
- R-12546-D (November 20, 2009): Stays the requirement for an approved Discharge Plan prior to injection (per original Order 12546) and allows DCP to inject, with a cap of 4.0 MMSCFD and pressure of 1,800 psi
- R-12546-E (January 28, 2010): Extends R-12546-D for 60 days
- R-12546-F (April 19, 2010): Extends R-12546-E for 90 days
- R-12546-G (July 19, 2010): Extends R-12546-F until new hearing
- R-12546-H (June 6, 2011): Denial of request for hearing extension by adjacent landowners, and acknowledgement of new NMOCD Discharge Plan Requirements (May 10, 2011) that Linam Gas Plant does not require a Discharge Plan
- R-12546-I (July 28, 2011): Formally removes the requirement for a Discharge Plan and lifts the caps of 4.0 MMSCFD and pressure of 1,800 psi and restores original allowed pressure to 2,644 psi with no cap on volume

The well was spudded on October 21, 2007; TD of 9,213 feet reached on November 16, 2007. Injection began in December 2009, following the receipt of Order R-12546-D, following the cap of 4.0 MMSCFD and pressure of 1,800 psi. Following the July 28, 2011, Order R-12546-I, DCP is now free to inject as much TAG as necessary, given the pressure limit of 2,644 psi.

Table 1: Summary of Reports and Permits

No.	Form	Submitted	Approved	Notes
1	C-108 – approval to drill & inject	September 12, 2005	March 5, 2006 Order #R-12546 and Orders R-12546A to I (July 28, 2011)	Appendix A
2	C-101 App. To Drill	Sept. 25, 2007	Oct. 1, 2007	Appendix A
3	O & G Plugging bond	na	na	Bond # 104907148
4	C-102 – Well Location	Sept. 28, 2007	Sept. 28, 2007	Appendix A
5	C-103 – spud	Oct. 21, 2007	Oct. 31, 2007	Appendix A
6	C-103- Cond. & Cmt	Nov. 1, 2007	Nov. 5, 2007	Appendix A
7	C-103 – Inter. & Cmt	Nov. 5, 2007	Nov. 19, 2007	Appendix A
8	C-103 Long Str. & Cmt	Nov. 29, 2007	Dec. 7, 2007	Appendix A
9	C-103 – Logging program	Dec. 20, 2007	Jan. 7, 2008	Appendix A
10	C-144 Pit Closure	Jan. 30, 2008	Jan. 30, 2008	Appendix A
11	C-144 Pit Closure (remediation)	March 19, 2008	March 19, 2008	Appendix A
12	C-103 MIT & TA	Jan. 19, 2009	Feb. 2, 2009	Appendix A
13	C-105 – Well completion	Feb. 10, 2009	Feb. 10, 2009	Appendix A
14	C-103 Return to Inj.	July 2, 2009	July 7, 2009	Appendix A
15	C-103 Return to Inj.	July 30, 2009	July 30, 2009	Appendix A
16	C-103 - MIT	July 30, 2009	July 30, 2009	Appendix A

3.3 WELL DESIGN

The well was designed to allow testing the suitability of the Brushy Canyon (5,000 to 5,300 feet) and the Bone Springs (8,700 to 9,000 feet) for acid gas injection. If tests were successful, the well would be completed in one or both of the target formations.

Planning and Well Design

As shown in Figure 3 and Appendices B and C, the well was designed to be drilled in 3 stages, using bit sizes of 17-½, 12-¼ and 8-¾ inch bits for boring, and 13-$^3/_8$, 9-$^5/_8$ and 7 inch casing. The 17-½ surface hole and 13-$^3/_8$ casing would be advanced to approximately 530 feet to isolate any fresh-water units, the 12-¼ hole and 9-$^5/_8$ casing would be set at approximately 4,200 feet in the Grayburg, and the "long string" 8-¾ inch bore and 7 inch casing would extend to total depth.

Metallurgy

The casing was constructed of conventional steel pipe, in accordance with API specifications. The Christmas tree and tubing, however, were designed to be corrosion-resistant, due to their constant contact with the TAG stream. As seen in Appendix B, the Christmas tree, designed and built by Wood Group, contains corrosion-resistant material in all surfaces contacting the TAG. From the wellhead, the TAG will be carried to the production packer via 3-½ inch L-80 tubing. The Schlumberger QL 7X4 production packer, set at 8,750 feet, is constructed from Incoloy 925 material.

Drilling and Mud Program

Detailed specifications for step-by-step drilling procedures are also included in Appendix C. The well was designed using a conventional three-string configuration, to be cased to total depth. The drilling plan provided detailed bottom-hole assembly (BHA) schedules for each segment, as well as the sequence of the collars and drill pipe. Estimated quantities were also included for mud, water and other supplies.

A comprehensive mud program was developed by Eagle Drilling Fluids, and is included in Appendix F. This program included the basic materials (e.g., bentonite, barite), loss control materials, chemicals, thinners, lost circulation materials and other miscellaneous special products.

The program called for the ideal mud weight and viscosity for each drilling segment and depth, and identified potential problem zones and suggested responses. The program also provided specific mixing programs for each type of mud, and instructions for maintaining the proper weight and viscosity.

Cementing

Halliburton developed the cementing program, and provided the cementing services during the drilling of the well (Appendix E). Halliburton calculated the volumes required in each cement stage, and recommended cement types, additives, weights, and total cement volumes to achieve the goal of a good and reliable fill and bond for each casing segment.

Stand-alone jobs were developed for the surface, intermediate and production casings. The production casing job entailed a stage-two process. Stage 1 was designed to fill 1,000 feet of annulus, from total depth to below the diverter valve (DV) at 5,686 feet. The DV was then opened and the second stage, consisting of 4,500 feet of lead cement and 3,500 feet of tail cement, were pumped into the well.

In each instance, cement returns to the surface were observed.

Completion

On December 12, 2007, Tyler Well Services moved in and rigged up their workover rig and began completion operations by installing the 3-½ inch tubing and drilling out the DV and cement plugs. After cleaning and circulation, Schlumberger was mobilized and ran the cement bond logs (CBL) on December 13, 2007. On December 14 - 15, Schlumberger rigged in and perforated the production casing from 8,710 to 9,085 feet with a total of 750 shots. The well was swabbed and cleaned and shut in.

On December 18, 2007, the well was re-opened and tested with 2 % KCl water, successfully receiving 5-½ barrels per minute. From December 19 to December 23, 2007, the well was acidized, swabbed, cleaned and conditioned. The well was then shut in and secured for a 7-day pressure test.

On January 19, 2008, following additional testing, a mechanical integrity test (MIT) was conducted, testing the 7 inch casing at 600 psi for 30 minutes. After the successful test was completed, a drillable bridge plug was set at 8,650 feet, topped with 45 feet of cement. Following a successful pressure test, the well was secured and temporarily abandoned in anticipation of the installation, testing and operation of the topside compressor facility.

On July 20, 2009, DCP Midstream re-entered the well and drilled out the bridge plug and cement. A permanent packer was set at 8,750 feet, and 3-½ inch, 9.3 pound/foot tubing was installed, along with a subsurface safety valve (SSV) at 259 feet. Diesel fuel was installed to fill the annulus between the production casing and the tubing. Approximately 15,000 gallons of 15% HCl was pumped down the tubing to reconfirm the injection capacity. The remote panel for the SSV was installed and tested (Appendix L), and the well head was secured pending completion of the topside compressor facility.

Safety

Every effort was made to execute the planned safe operation from the drilling, to completion, to the operation of the well. A pre-spud meeting was held prior to drilling operations to familiarize the drilling and service company personnel with plant safety rules, and a Company Safety representative monitored compliance. During major service company operations like coring, logging, running casing, cementing, perforating, etc. mandatory safety meetings were held to discuss safe procedures and answer any questions personnel might have prior to each job.

As approved by NMOCD in the Rule 11 plan for the site, H_2S monitors are located near the wellhead and inside the wellhead cellar to monitor for any possible leaks of H_2S. The SSSV installed at 257 feet below the surface is designed to fail "closed" if constant hydraulic pressure applied to it through the control line is ever interrupted. In other words, if something as drastic as the wellhead being sheared off at the surface ever occurred, the SSSV would shut itself in automatically, sealing off the injected zone from the surface.

3.4 DRILLING, COMPLETION AND OPERATION

The final well design and AFE for the Linam AGI #1were completed in July of 2007 (Appendix B). The final AFE called for a dry-hole cost of $2,143;625, a completion cost of $1,013,210, and a total cost of $3,156,835. Although the completion costs included $200,000 for engineering to develop the surface facility, no additional surface activities were included in this AFE. Actual drilling, cementing and casing closely matched the original design (Appendix C), as seen in Table 2 below. The final configuration of the well is shown in Figure 3.

Table 2: Linam AGI #1 Design Comparison

Original Design			As Drilled		
Casing (inches)	Depth (ft)	Cement (sx)	Casing (inches)	Depth (ft)	Cement (sx)
13 3/8	530	600	13 3/8	580	475
9 5/8	4,200	1300	9 5/8	4,212	1325 + 375
7	9,100	1200	7	9,120	1,460

The well was spudded on October 21, 2007, and a TD of 9,213 feet reached on November 16, 2007 and the rig was released on November 20, 2007. The well was advanced by drilling a 17-½ inch hole to 580 feet, and cased with 580 feet of 13-$^3/_8$ inch 48 pound/foot surface casing, cemented to the surface with 475 sacks circulated to the surface on October 22, 2007. Pressure testing at 600 psi for 30 minutes was successful. Daily drilling reports are included in Appendix D.

Drilling then continued to 4,212 feet with a 12-¼ inch hole. This segment was cased with 9-$^5/_8$ inch 40 pound/foot intermediate casing, cemented to the surface with 1,325 sacks lead and 375 sacks tail, and circulated to the surface, on November 2, 2007. This casing was tested successfully at 1500 psi for 30 minutes. Cementing reports are included in Appendix E.

After drilling an 8-$^3/_4$ inch hole to approximately 5,290 feet, Schlumberger was mobilized to the site to perform a Drill Stem Test (DST) in the Brushy Canyon Zone, from 5,023 to 5,288 feet. The test was conducted on November 6, 2007, and showed that the Brushy Canyon Zone had little potential for injection (Appendix K). Drilling continued until the ultimate total depth of 9,213 feet was reached on November 16, 2007. After the well was conditioned it was logged by Schlumberger on November 16, 2007. Logging included Laterolog, Density, Neutron, Gamma Ray, Formation Micro Imager (FMI), and 21 rotary sidewall cores (Appendices G and H).

On November 20, 2007, the 7 inch, 26 pound/foot production casing was cemented in place at 9,120 feet. The cement job involved two stages. Stage 1 consisted of a lead of 625 sacks of Halliburton Light Premium, and a tail of 485 sacks of POZ Premium. After 6 hours, the DV, located at 5,686 feet, was opened and the Stage 2 lead of 360 sacks of Interfill H was emplaced. This was followed by a tail of 510 sacks of POZ Premium. Approximately 87 barrels of cement returned to the reserve pit.

On December 10, 2007, Tyler Well Services rigged up their Rig No. 2 workover rig, and drilled out the DV. On December 13, 2007, Schlumberger returned to the site and ran their I-Scanner Cement Bond Log (CBL). The logs showed good isolation around the Bone Springs injection zone and good isolation in the lower part of the 9-$^5/_8$ inch – 7 inch overlap (Appendix C).

Initial completion operations began with perforating the 7 inch casing from 8,710 to 9,085 feet with a total of 775 shots. After perforation, the well was swabbed and "pickled" with 80 barrels of 15% hydrochloric acid (HCL) to clean the well for the subsequent injection testing (Appendix I).

On January 3, 2008, an acid job (running from 3 barrels per minute to 9 barrels per minute) was conducted. This was followed by a step-rate test from 2 to 9 barrels, at time steps of 30 minutes. This test was followed on January 4, 2006, by a 9.5 hour, 2 barrel per minute injection test, and a subsequent 221 hour falloff test. The tests indicated that the Bone Springs interval had excellent properties for injection (Appendix J).

Because the top-side compressor facilities and the approved underground pipeline were not completed, the well was tested for mechanical integrity and temporarily abandoned with a drillable bridge plug, set at 8,160 feet.

On July 20, 2009, the well was re-entered to return it to operational status. The bridge plug was drilled out and a packer was installed at 8,750 feet. The final 3-½ inch, 9.3 ppf injection tubing was installed with a subsurface safety valve (SSV) attached at 259 feet below grade, and 15,000 gallons of 15% HCl was pumped down the well to test injection capacity. The remote control panel for the SSV was set up and tested (Appendix L). Following a Mechanical Integrity Test on July 28, the well was approved for injection. After additional testing and calibration, full-scale injection began in December 2009.

3.5 POTENTIAL IMPACTS ON NEARBY WELLS

As described further in Section 5 below, the immediate area of the well is located above the northern end of the Permian Basin's Central Platform, a buried structural high which strongly influences the structure and stratigraphy of the Permian geology in this area. During the feasibility study and preparation of the C-108 application, Geolex researched the locations, depths, ownership and status of all of the recorded wells within one mile of the Linam AGI #1 (Figure 4). These 20 wells (in addition to Linam AGI #1) are summarized in Table 3 below.

Table 3: Wells within One Mile of Linam AGI #1

API#	OPERATOR	WELLNAME	PLUGDATE	SPUDDATE	DEPTH	STATUS	DIST (Mi)	FORMATION(S)
3002538576	DCP MIDSTREAM, LP	LINAM AGI 001	na	10/21/2007	9213	Active	0.00	BONE SPRINGS
3002505519	GORDON M CONE	SUPERIOR ST. 001	7/8/1942	6/14/1942	810	Plugged	0.00	SHALLOW/ABAND
3002505514	GORDON M CONE-ST PX	BERRY ST. 001	7/13/2006	11/17/1943	4609	Plugged	0.02	PENROSE
3002534786	ENERQUEST RESOURCES, LLC	GOODWIN 30 001	5/3/2000	12/29/1999	7700	Plugged	0.09	ABO
3002505513	CONOCO INC	ST. GG 30 001	9/10/1987	6/13/1962	7732	Plugged	0.09	ABO
3002526163	J S ABERCROMBIE MINERAL	ST. 30 001	3/12/1979	12/27/1978	7550	Plugged	0.25	ABO
3002520651	CONOCO INC	GOODWIN 002	1/2/1900	1/2/1900	7600	Plugged	0.25	ARKANSAS JUNCTION;SAN ANDRES
3002520663	MACK ENERGY CORP	ST. GG 3O 003	12/20/1996	11/22/1964	7600	Plugged	0.26	ABO
3002520079	MACK ENERGY CORP	ST. GG 3O 002	1/2/1997	2/27/1963	7581	Plugged	0.35	ABO
3002505512	M BRAD BENNETT INC	GOODWIN 30 001	7/1/1988	12/21/1961	8200	Plugged	0.35	ABO
3002538544	MACK ENERGY CORP	BOYZ FEE 001	na	8/17/2007	8028	Active	0.44	ARKANSAS JUNCTION;SAN ANDRES
3002521024	STEVE GOSE	GRAHAM ST. 001	2/23/1965	12/5/1964	7490	Plugged	0.50	ABO
3002520027	UNICHEM INTERNATIONAL	ST. WME 002	2/26/1991	6/3/1963	7460	Plugged	0.56	ABO
3002538957	MACK ENERGY CORP	BOYZ FEE 002	na	7/14/2008	7560	Active	0.68	ARKANSAS JUNCTION;SAN ANDRES
3002520107	PETRO LEWIS CORP	ST. A 002	12/29/1981	4/16/1963	7691	Plugged	0.71	ABO
3002505515	AMERADA HESS	ST. WME 001	7/9/1957	4/12/1956	4050	Plugged	0.75	PENROSE
3002524770	CONOCO INC	ST. B-19 001	1/2/1900	1/2/1900	7800	Plugged	0.79	ABO
3002521183	AGUA INC	GOODWIN 031	3/2/2004	6/21/1965	7602	Plugged	0.79	
3002521832	PENNZENERGY E&P LLC	CONOCO ST. 001	9/23/1966	8/4/1966	11675	Plugged	0.79	ELLENBURGER
3002503976	CONTINENTAL OIL	GOODWIN 003	4/23/1973	6/23/1961	8582	Plugged	0.79	ABO
3002534533	XTO ENERGY, INC	MONUMENT 36 ST. 003	na	6/2/1999	7462	Active	0.93	GOODWIN;ABO

Of the 20 wells, 3 are active and 17 have been plugged and abandoned. The only well in the one-mile radius that penetrated the Bone Springs target zone was Conoco State 001 (see Figure 4); this well was plugged and abandoned in 1973. During the well research performed for the C-108, the NMOCD records for this well and all other plugged and abandoned wells were reviewed to verify the effectiveness of their plugging methods. All of these wells were plugged in accordance with applicable NMOCD requirements.

Our research indicated that there is no reasonable probability of impacts to existing wells by the drilling and operation of Linam AGI #1.

3.6 CALCULATED AREAS OF INJECTION

Using the available data of the Bone Springs reservoir, Geolex has calculated the areas of injection after 30 years of operations at both the current rate of 4.6 MMSCFD and the projected increased rate of 7.0 MMSCFD. These calculations are presented in detail in Appendix J, shown in Figure 5, and summarized in Table 4 below. Detailed calculations and data are discussed in Section 5.0.

Table 4: Calculated Areas of Injection After 30 Years

Initial Injection Rate of 4.6 MMSCFD		Proposed Injection Rate of 7.0 MMSCFD	
Area of Injection (sq. ft)	117,196,499	Area of Injection (sq. ft)	178,342,498
Area of Injection (Acres)	292	Area of Injection (Acres)	445
Radius of Injection (Miles)	0.38	Radius of Injection (Miles)	0.47

As seen in Figure 5, the areas of injection (adjusted to include the influences of formation thinning to the south and the bounding locations of the known faults) do not reach the only well penetrating the Bone Springs (Conoco State 001; see also Figure 4).

We are confident that the planned rates of injection, either at 4.6 MMSCFD or the projected increased rate of 7.0 MMSCFD, will not impact any known existing wells in the area.

4.0 REGIONAL AND LOCAL GEOLOGY AND HYDROGEOLOGY

4.1 GENERAL GEOLOGIC SETTING

The Linam AGI #1 is located on the north end of the Central Basin Platform, a buried structural high in the Permian Basin (Figure 6). The persistent relief of this platform throughout the deposition of Permian sediments in the larger basin greatly influenced the stratigraphy and local structure of the surrounding formations. Originally overlain be Ordovician and Mississippian deposits, the platform was draped by younger Pennsylvanian and Permian rocks, and was faulted along generally northwest-southeast and northeast-southwest normal faults. These faults continued to grow during lower (Wolfcamp and Leonardian) time, before being buried by the younger Guadalupian and Ochoan series.

4.2 BEDROCK GEOLOGY

The Bone Springs Group (Leonardian) was deposited in this area along relatively steep slopes of the northern end of the Central Platform, and consists of relatively porous and permeable clastic carbonates, commonly in the form of debris fans from the adjacent, shallow-water Abo Reef (Figure 6).

As seen in Figure 7, the Abo Reef closely parallels the trend of the Central Platform, forming a narrow "fairway" west of the Linam Gas Plant. In contrast, the Bone Springs facies found west and north of the platform (in the Delaware Basin and the San Simon Channel) are not productive. This is due in part to the location of the Bone Springs below the oil-water contact, easily seen in the trend of the Abo Reef play (Figure 7).

4.3 LITHOLOGIC AND RESERVOIR CHARACTERISTICS OF THE BONE SPRINGS

Figure 7 also includes isopach contours on the Bone Springs. The net thickness falls to zero beneath the plant, but thickens to over 100 feet in Section 30, approximately one mile north of the plant. Note that there are two north-dropping normal faults between the plant and the target area. Seismic data indicate that these faults were active during the deposition of the Bone Springs, and enhanced the accumulation of the detrital material that formed the reservoir.

A total of 19 side wall cores were collected from the Bone Springs. Analyses of these cores (see Appendix G) show porosity ranging from 0.4 to 15.8 percent, and permeability from 0.013 to 165 milliDarcies. The lithology was primarily dolomite, locally grading into dolomitic limestone. Fossil fragments were abundant, and the major porosity was vuggy in nature, developed by diagenetic dissolution of secondary calcite.

Analyses of the geophysical logs (Appendix H) showed porosities of 2 to 10 percent in the target interval. Based on the log analyses, 8 intervals between 8,710 and 9,085 feet were perforated with a total of 750 shots.

The perforated intervals total 280 feet, in which an average porosity of 6 % was calculated. The gross net porosity (280 ft x 0.06) is 16.8 feet. Correcting for a residual water ratio (Swr) of 0.45, the available porosity is 9.2 feet.

4.4 FORMATION FLUID CHEMISTRY

In January 2008, samples of the Bone Springs formation fluid were collected and analyzed. The formation fluid is sodium chloride-rich brine with total dissolved solids of 73,412 milligrams per liter. A complete copy of the analyses is included in Appendix K.

4.5 GROUNDWATER HYDROLOGY IN THE VICINITY OF THE PROPOSED INJECTON WELL

Groundwater in the area of the well site is found in shallow, unconfined aquifers hosted by the Quaternary alluvial and aeolian surficial deposits, and the Tertiary Ogallala Formation. Groundwater may also occur in local, confined sandstone beds in the deeper "red beds" of the Triassic Dockum Group.

A review of the New Mexico State Engineer's database identified 7 water wells within one mile of the Linam AGI #1. These wells are summarized in Table 5 below, and located in Figure 9. All of these wells are completed in very shallow units, either the alluvium and/or the Ogallala. Due to their distal locations and shallow completions, there is no potential for impacts from the Linam AGI #1.

Table 5: Identified Water Wells within One Mile of Linam AGI #1

SOURCE	UTME	UTMN	Distance (m)	Well Depth (ft)	Water Depth (ft)	Owner
Shallow	659878	3621568	566	60	50	R. Keith
Shallow	659118	3621119	895	68	50	R. Keith
Shallow	658996	3620960	1015	206	84	Abbot Bros.
Shallow	659035	3621493	1083	60	50	R. Keith
Shallow	658677	3620972	1331	62	50	R. Keith
Shallow	639309	3620060	1184	NR	NR	Unknown

5.0 RESERVOIR CHARACTERIZATION AND MODELING

5.1 GEOPHYSICAL LOGS AND FMI

After reaching the total depth, the well was conditioned and logged by Schlumberger with a suite of geophysical tools. The suite included:

- Density-Neutron composite, to determine overall and fluid-saturated porosity,
- High-Resolution Resistivity Laterolog array, to explore lithology, fluid conditions, and mud-formation interactions,
- Borehole Compensated Sonic logging, to examine rock physical properties, and provide an independent calculation of porosity,
- Spinner-Temperature-Pressure survey, to identify permeable zones where fluids were moving in and out of the borehole,
- Structural Dip Meter logging, which determined the angular orientations of formation features, and
- Schlumberger FormationMicroImager (FMI), a proprietary logging tool that images the small-scale features along the walls of the borehole, particularly faults, fractures and porous zones.

The most directly useful logs were the Density-Neutron composite, which allowed Geolex geologists to select specific zones for perforation (see Figure 8).

5.2 SIDEWALL CORING

Following the geophysical logging, Schlumberger collected a total of 22 side wall cores, 19 of which were in the Bone Springs interval (Appendix G). As discussed in Section 4.3 above, laboratory analyses showed porosities ranging from 0.4 to 15.8 percent, and air permeabilities ranging from 0.013 to 165 milliDarcies. Although geophysical logging cannot directly measure permeability, the porosity values from the Density-Neutron logs (6 % in the injection zone) comfortably span the laboratory core values.

5.3 RESERVOIR TESTING

Reservoir testing included a drill stem test in the Brushy Canyon Zone, from 5,023 to 5,288 feet, and injection-falloff and step-rates tests in the Bone Springs (Appendix K). Although good packer seal was achieved in the drill stem test, there was very little flow from the tool, indicating very poor permeability in the Brushy Canyon.

The injection and fall-off test, operated and analyzed by MHA Petroleum Consultants, began with a 9.5 hour period of injection water at 2 barrels per minute, followed by a 221 hour fall off. Pressure was continuously recorded at the surface and by a bottom-hole probe. The analyses indicated a permeability of 2220 milliDarcy-feet, and possible intersecting barriers at 1800 and 2000 feet from the well. The fall-off test analysis further concluded that the reservoir has a minimum pore volume of 47 to 55 million barrels, and that only 1000 psi increase in the reservoir would allow over 230 million barrels of compressed TAG.

The step-rate test involved pumping water into the well at rates of 1 to 9 barrels per minute, using 30-minute intervals for each step. Injection rates, surface and bottom pressures were continuously recorded. Following the final injection step, pressure was monitored for fall back. The step test final surface pressure was 3600 psi. After 25 minutes, the pressure had fallen to 589 psi and was essentially zero the following day.

5.4 INTERPRETATION AND IMPLICATIONS

The very rapid decay of well head pressure after cessation of injection in both the fall-off and step-rate tests indicates that the reservoir has excellent injectivity, and adequate volume for the anticipated injection volumes. As discussed above, a capacity of 230 million barrels at a reservoir pressure increase of 1000 psi would compare very favorably versus the anticipated 30-year injection volume of approximately 75 million barrels, at the surface rate of 7.0 MMSCFD.

The step test (Figure 10) shows that there was no inflection or "breakdown" in the pressure/rate curve over the range tested. The area determined by the estimated injection pressures and projected range of injection rates is well below the maximum pressure set by Order R-12546. The well has a large capacity for additional injection without reaching the allowed maximum pressure.

5.5 RESERVOIR MODEL AND AREA OF IMPACT

Using the AQUAlibrum software, Geolex has calculated the anticipated volumes and areas for injection over 30 years, at the rates of 4.6 and 7.0 MMSCFD. These calculations are presented in Tables J-1 and J-2 (Appendix J). These calculations incorporate the molar ratios of H_2S and CO_2, known well head pressures and temperature, and measured formation temperature and pressure. These factors allow calculations of the actual density of the TAG (here a supercritical fluid) at reservoir conditions, and the corresponding reservoir volumes of TAG for the respective surface volumes.

Under reservoir conditions the compressed TAG, which had a specific gravity of 0.34 at the well head, had increased its density to 0.81 at reservoir conditions. The volume at the surface (6898 barrels for 7.0 MMSCFD) also was compressed to 2899 barrels, or 42% of the surface volume.

As described earlier in Section 3.6 and Table 4, the areas and radii, calculated using AQUAlibrium, are 29 acres and 0.38 miles at 4.6 MMSCD, and 445 acres and 0.47 miles at 7.0 MMSCFD (Figure 5).