



45031 & 45032

**APPENDIX XII-1**  
Operating Plan for  
Minerva South CCS No. 001



## TABLE OF CONTENTS

FACILITY INFORMATION .....	1
PROPOSED OPERATING PLAN FOR MS CCS 1 .....	1
1 INJECTION RATE AND PRESSURE .....	1
1.1 Injection Rate.....	1
1.2 Injection Pressure.....	1
2 CO <sub>2</sub> STREAM .....	2
2.1 CO <sub>2</sub> Volume .....	2
2.2 CO <sub>2</sub> Stream Characteristics .....	2
3 MECHANICAL INTEGRITY .....	2
3.1 Annulus Fluid and Pressure.....	2
3.2 Pressure Gauges .....	2
4 INJECTION WELL INSTRUMENTATION AND MONITORING SYSTEMS.....	3
4.1 Continuous Recording Devices .....	3
4.2 Corrosion Monitoring.....	3
4.3 Mechanical Integrity Monitoring .....	4
5 ALARMS AND EMERGENCY SHUTDOWN .....	4
6 WELLHEAD IDENTIFICATION AND PROTECTION .....	5
7 WELL WORKOVERS .....	5
7.1 Stimulation Program.....	5
8 CONTINGENCIES AND PREVENTIONS.....	5
8.1 Contingency Plans for Shut-In Or Well Failures .....	5
8.2 Precautions to Prevent Well Blowouts .....	6
9 EMERGENCY SHUTDOWN .....	6
9.1 Circumstances Under Which Injection Must Cease.....	6
9.2 Shutdown Response.....	7
10 RECORDKEEPING.....	7
11 REPORTING.....	8
11.1 Quarterly .....	8
11.2 Within 30 Days .....	9
11.3 Within 24 Hours .....	9
12 NOTIFICATIONS.....	9



## TABLES

Table XII.1-1 Operating Conditions for MS CCS 1 and MS CCS 2

Table XII.1-2 Proposed CO<sub>2</sub> Stream Composition for Project Minerva



## FACILITY INFORMATION

Facility Name:	Minerva Facility
Injection Wells:	Minerva South CCS Well No. 001 (MS CCS 1) Minerva South CCS Well No. 002 (MS CCS 2)
Facility Contact:	David Cook, CEO 5599 San Felipe St., Ste. 1450, Houston, Texas 77056 (713) 419-6808; <a href="mailto:dcook@gcscarbon.com">dcook@gcscarbon.com</a>
Well Locations:	Sec 3, T12S, R13W, Cameron Parish, Louisiana MS CCS 1 (NAD 1927) Surface: 30° 02' 34.10"N, 93° 40' 20.63"W Bottom-Hole: 30° 02' 34.10"N, 93° 40' 20.63"W MS CCS 2 (NAD 1927) Surface: 30° 02' 33.84"N, 93° 40' 20.48"W Bottom-Hole: 30° 02' 13.74"N, 93° 40' 42.07"W

## PROPOSED OPERATING PLAN FOR MS CCS 1

The Louisiana Department of Conservation and Energy (C&E) has primary permit and enforcement authority (primacy) over Class VI Injection Wells through their Underground Injection Control (UIC) program. Gulf Coast Sequestration, LLC (GCS) will implement the proposed operating plan for Minerva South CCS Well No. 1 (MS CCS 1) according to the requirements of LAC 43:XVII §3601-3633 and with approval from the C&E Secretary of Conservation (Secretary).

### 1 INJECTION RATE AND PRESSURE

#### 1.1 INJECTION RATE

Project Minerva will utilize a sequential completion strategy, starting with the bottom interval and progressing upwards. Targeted injection rates are set at 17 MMSCF/D in MS CCS 1 and 16.5 MMSCF/D in MS CCS 2 for the bottom interval (Interval 1) for 17 years and 23 MMSCF/D into the intermediate interval (Interval 2) of MS CCS 1 and MS CCS 2 for 13 years. The project will inject a combined average range of 0.547- 0.746 metric tons (MMT) of CO<sub>2</sub> per year over its 30-year lifespan, split between the two injection wells, as defined in Table XII.1-1

#### 1.2 INJECTION PRESSURE

Injection induced pressure will not exceed 90% of the fracture pressure of the zone. The bottom-hole pressures are significantly smaller than the estimated fracture pressure and induced seismicity pressure. The initial formation pressure is based on the most-likely initial formation pressure gradient of 0.457 psi/ft.

The most-likely value of the minimum horizontal stress gradient is assumed to be 0.85 psi/ft,



as provided in Section 2.5.1.2 (Total Minimum Horizontal Stress) of the Project Minerva Narrative. The depth of the deepest completion interval in MS CCS 1 is approximately 9,996 ft TVD, which calculates to a minimum horizontal stress of approximately 8,496 psia. Assuming a safety factor of 90%, this gives an estimate of the formation fracturing pressure to be approximately 7,647 psia at the same depth. This is a conservative estimate as it assumes no cohesion in the formation, i.e. the formation parts as soon as the effective minimum horizontal stress is less than zero. The induced seismicity pressure is estimated to be 9,996 psia at a depth of 9,996 ft TVDSS at the pressure gradient of 1 psi/ft.

## 2 CO<sub>2</sub> STREAM

### 2.1 CO<sub>2</sub> VOLUME

Project Minerva is designed to permanently store a total of 19.0 MMT, in the base case. This mass will be achieved by injecting at an average rate ranging from 0.547-0.746 MMT/yr for 30 years. Table XII.1-1 provides a detailed breakdown of the injection rates for each injection interval of MS CCS 1.

### 2.2 CO<sub>2</sub> STREAM CHARACTERISTICS

Table XII.1-2 provides the proposed CO<sub>2</sub> stream specification for Project Minerva. This specification is designed to ensure safe operation of the project and ensure no-endangerment of the USDW. Project Minerva envisions sourcing CO<sub>2</sub> volumes from multiple sources of CO<sub>2</sub> from industrial facilities in Lake Charles industrial corridor in southwestern Louisiana and Beaumont industrial corridor in southeastern Texas and are likely to be higher purity CO<sub>2</sub> due to the lower cost of capture for such emissions. These sources have the ability to meet or exceed the proposed CO<sub>2</sub> specification. The reservoir simulation model fully accounts for the CO<sub>2</sub> specification.

## 3 MECHANICAL INTEGRITY

GCS will maintain mechanical integrity of the injection well at all times, except when doing well workovers, well maintenance, or well remedial work approved by the regulatory agency with authority over the well.

### 3.1 ANNULUS FLUID AND PRESSURE

The annulus between the tubing (OD: 4.5”) and long-string (ID: 8.535”) casing will be filled with >9.0 CaCl<sub>2</sub> inhibited brine with a non-corrosive fluid. Final chemical formulation and concentration will be defined with the fluids vendor selected for the project. GCS will maintain pressure on the annulus that exceeds the operating injection pressure presented in Table XII.1-1.

### 3.2 PRESSURE GAUGES

GCS will install pressure gauges on the wellhead that show pressure on the injection tubing and tubing-casing annulus. The digital or analog gauges will be designed to read in increments of 10 psig and will be properly calibrated and maintained in good working order.



The pressure valves onto which the pressure gauge is affixed will have one-half inch female fittings, or equivalent to meet required API wellhead or ASME pipe design requirements for safety.

## **4 INJECTION WELL INSTRUMENTATION AND MONITORING SYSTEMS**

### **4.1 CONTINUOUS RECORDING DEVICES**

GCS will install continuous recording devices on the injection well, and ensure they are used and maintained in proper working order. The devices will monitor surface injection or bottom-hole pressure; flow rate, volume and/or mass, and temperature of the carbon dioxide stream; tubing-casing annulus pressure and annulus fluid volume; any other data specified by the regulatory authority.

The continuous recordings will be digitally recorded, and the recording instrument will be weatherproof or housed in weatherproof enclosures if located in areas exposed to climatic conditions.

The Testing and Monitoring Plan (Attachment D, Section 4.0) provides additional information regarding the continuous monitoring details, location, equipment, accuracy, and frequency.

### **4.2 CORROSION MONITORING**

All components of MS CCS 1 that are in direct contact with the carbon dioxide stream and formation fluids in the Injection Zone will be constructed of noncorrosive materials, 25CRW-125 for 9 5/8" casing and 4 1/2" tubing.

The CO<sub>2</sub> stream will be routed through a loop installed in-parallel with the pipe at the surface facilities to monitor for corrosion of the injection wells. The loop will be constructed of 25Cr corrosion resistant alloy (CRA), matching the material of the 9 5/8" long string casing installed across the Injection and Confining Zones. While all efforts will be made to operate the corrosion loop at downhole temperatures, during detailed engineering an evaluation will be made to determine the practicality and ability to simulate well conditions. Final technology selection will be completed after detailed engineering.

Corrosion monitoring of the loops will be performed on a quarterly basis to inspect for loss of mass, thickness, cracking, pitting, and other signs of corrosion, and to ensure that the well components meet the minimum standards for material strength and performance set forth in LAC 43:XVII §3617.A.2. Quarterly inspections will be conducted by a Level 3 Non-Destructive Testing (NDT) and Non-Destructive Examination (NDE) certified inspectors and technologies, including but not limited to, Ultrasonic and Radiography equipment.

The Testing and Monitoring Plan (Attachment D, Section 5.0) provides additional information regarding monitoring, inspection, location, and frequency.



### 4.3 MECHANICAL INTEGRITY MONITORING

In accordance with LAC 43:XVII §3627.A.2, GCS will conduct mechanical integrity testing as follows:

- The long string casing, injecting tubing, and annular seal shall be tested by means of an approved pressure test with a liquid or gas
  - After initial well construction as part of the Pre-Operating requirements (See Attachment C)
  - At least once every 12 months witnessed by an agent with the UIC Program, and
  - After there has been a well workover involving the unseating or disturbing of the injection tubing or annular seal system of the packer;
- A pressure fall-off test shall be conducted upon completion of the well and every five years thereafter to monitor pressure buildup in the injection zone. More frequent testing may be required by the C&E Secretary based on site-specific information;
- Temperature logging will be used as the primary test to demonstrate external integrity of the injection wells (LAC 43:XVII §3627.A.3.a-b,), details provided in the Testing and Monitoring Plan (Attachment D, Section 7.2.1);
- A Digital Temperature Sensing (DTS) fiber optic cable will be installed on the long-string of MS CCS 1 to provide continuous external mechanical integrity monitoring of the wellbore;
- A DTS mechanical integrity test (DTS MIT) will be performed as an alternative test at least once every 12 months to corroborate the data required from the Temperature logging, as described in the Testing and Monitoring Plan (Attachment D, Section 7.2.2). Once sufficient validation of the data is made, GCS will submit a request to the C&E Secretary to utilize the alternative method for external MIT demonstration;
- If supplemental testing is requested by the C&E Secretary (LAC 43:XVII §3627.A.4 and §3627.A.7), a casing inspection log shall be run to determine the presence or absence of corrosion in the long-string casing, Testing and Monitoring Plan (Attachment D, Section 7.2.3).

Except during workovers or routine maintenance, any well which is not operational shall conform to the mechanical integrity requirement of LAC 43:XVII §3621.A.3-4 and shall sustain a positive pressure on the annulus during the period of non-use. If GCS plans to take a well out of operation, a plan to assure the mechanical integrity of the well during non-use will be submitted to the Secretary.

## 5 ALARMS AND EMERGENCY SHUTDOWN

MS CCS 1 will be equipped with alarms and an automatic surface shut-off valve or other mechanical devices that provide equivalent protection. The alarms will be integrated with the automatic shutdown system. The emergency shutdown systems will be fail-safe, and



GCS will function-test all critical systems of control and safety at least once every six months. This includes testing of alarms, test tripping of emergency shutdown valves ensuring their closure times are within design specifications, and ensuring the integrity of all electrical, pneumatic, and hydraulic circuits. Test dates and results will be documented and will be made available for inspection by an agent of the regulatory authority.

If a shutdown is triggered or a loss of mechanical integrity is discovered, GCS will immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, GCS will take action by immediately ceasing injection and notifying the regulatory authority within 24 hours of shutdown. GCS will submit a plan to restore and demonstrate mechanical integrity to the satisfaction of the regulatory authority prior to resuming injection. After demonstrating mechanical integrity, GCS will notify the regulatory authority when injection can be expected to resume.

## **6 WELLHEAD IDENTIFICATION AND PROTECTION**

GCS will install and maintain a protective barrier around the wellheads, piping, and above ground structures that may be vulnerable to physical or accidental damage by mobile equipment or trespassers. An identifying sign will be placed at the wellhead of the injection well and will include at a minimum the operator name, well name and number, well serial number, section-township-range, and any other information required by the regulatory authority. The sign will be of durable construction with all lettering kept in a legible condition.

## **7 WELL WORKOVERS**

GCS will submit a work permit request form (Form UIC-17, or its replacement) to the regulatory authority prior to performing: well remedial work, well maintenance or repair, well or injection formation stimulation, well plug and abandonment or temporary abandonment, any other test of the injection well conducted by GCS, or well work of any kind. GCS will not commence work without prior written authorization from the regulatory authority.

### **7.1 STIMULATION PROGRAM**

All stimulation activities will be approved by the regulatory authority prior to conducting the stimulation. GCS will carry out the Stimulation Program for MS CCS 1 in accordance with the plan provided in Appendix XI-1 of the Project Minerva Narrative.

## **8 CONTINGENCIES AND PREVENTIONS**

### **8.1 CONTINGENCY PLANS FOR SHUT-IN OR WELL FAILURES**

MS CCS 1 will be equipped with alarms integrated with an automatic shutdown system (LAC 43:XVII §3621.A.7.a-c). The injection well will be equipped with a shutdown valve actuated by any of the following pressure scenarios:



- High-pressure approaching the designated Maximum Authorized Surface Injection Pressure (MASIP);
- Low-pressure that could indicate a potential surface leak;
- High/low pressure indicated on the tubing/casing annulus. This shutdown valve is intended to stop the flow of CO<sub>2</sub> into the injection well in the event of 1) a tubing leak, or 2) a casing, packer, or wellhead leak.

If an alarm or shutdown is triggered, the cause of the alarm or shutdown will be immediately investigated to identify the origin of the shutdown. GCS would also:

- Immediately cease injection operations;
- Take necessary steps to determine the presence or absence of a leak; and
- Provide verbal notification to the Secretary within 24 hours.

If the alarm or shutdown is not related to mechanical integrity and the cause of the alarm or shutdown is corrected, injection operations will resume.

If the mechanical integrity of the well is in question, the well will remain out of service until mechanical integrity of the well is restored to the satisfaction of the Secretary and they approve resumption of injection operations.

## 8.2 PRECAUTIONS TO PREVENT WELL BLOWOUTS

Except at specific times as approved by the Secretary, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall follow procedures such as those below to ensure that a backflow or blowout does not occur:

- Limit the temperature and/or corrosivity of the injectate; and
- Develop procedures necessary to assure that pressure imbalances do not occur.

## 9 EMERGENCY SHUTDOWN

### 9.1 CIRCUMSTANCES UNDER WHICH INJECTION MUST CEASE

Injection shall cease when any of the following circumstances arises:

- Failure of the well to pass a mechanical integrity test;
- A loss of mechanical integrity during operation;
- The automatic alarm or automatic shut-off system is triggered;
- A significant unexpected change in the annulus or injection pressure;
- The Secretary determines that the well lacks mechanical integrity; or



- The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Secretary determines that injection should cease.

## 9.2 SHUTDOWN RESPONSE

If a shutdown is triggered or a loss of mechanical integrity is discovered, GCS will immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, GCS will take action by immediately ceasing injection and notifying the regulatory authority within 24 hours of shutdown in accordance with the Emergency and Remedial Response Plan (Attachment G).

GCS will submit a plan to restore and demonstrate mechanical integrity to the satisfaction of the regulatory authority prior to resuming injection. After demonstrating mechanical integrity, GCS will notify the regulatory authority when injection can be expected to resume.

## 10 RECORDKEEPING

Operations and monitoring records will be maintained, and written monitoring reports will be submitted periodically to the Secretary in accordance with the requirements outlined in LAC 43:XVII §3629.A. Regardless of whether the State of Louisiana has primary permit and enforcement authority (primacy) for Class VI wells, GCS will submit all required submittals, reports, and notifications under (LAC 43:XVII §3605, 3607, 3615, 3617, 3619, 3621, 3623, 3625, 3627, 3629, 3631, and 3633) to the USEPA in an electronic format approved by the USEPA.

In accordance with LAC 43:XVII §3625.B.3 and §3629.A.6, GCS will maintain accurate records of the following:

- All data collected under LAC 43:XVII §3607 and 3619 will be retained throughout the life of the geologic sequestration project and for 10 years following site closure;
- Data on the nature and composition of all injected fluids collected pursuant to LAC 43:XVII §3625.B.2.b shall be retained at least 3 years after site closure. The Secretary may require GCS to deliver the records to the Secretary at the conclusion of the retention period.
- Pursuant to LAC 43:XVII §3629.A.4 the following monitoring data shall be retained for at least 10 years after it is collected:
  - Data collected from continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;
  - Results of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion;
  - Data and analyses from monitoring of the groundwater quality and geochemical changes above the confining zone(s);



- Results of pressure fall-off tests;
  - Indirect and direct testing and monitoring data to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure;
  - If required, data from surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW; and
  - Any additional monitoring data, as required by the Secretary, necessary to support, upgrade, and improve computational modeling of the area of review evaluation;
- Pursuant to LAC 43:XVII §3625.B.3 the following monitoring information shall recorded:
- the date, exact place, and time of sampling or measurements;
  - the individual(s) who performed the sampling or measurements;
  - the date(s) analyses were performed;
  - the individual(s) who performed the analyses;
  - the analytical techniques or methods used; and
  - the results of such analyses.
- Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at LAC 43:XVII §3633.A.6 and 3633.A.8 shall be retained for at least 10 years following site closure; and
- Records related to AOR modeling inputs and data used to support area of review reevaluations; data and reports enumerated in the previous subsection (§3629.A.6); well closure; site closure; and any records gathered during the post-injection site care period for at least 10 years following site closure.

The Secretary has authority to require GCS to retain any records required in LAC 43:XVII §3629.A.6 for longer than 10 years after site closure.

## 11 REPORTING

### 11.1 QUARTERLY

Quarterly reports, as specified in LAC 43:XVII §3629.A, will be submitted within thirty (30) days following the end of each 6-month period for which the report is being submitted. The reports will include the following information:

- Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;



- Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;
- A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;
- A description of any event which triggers a shut-off device required pursuant to LAC 43:XVII §3621.A.6 and the response taken;
- The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;
- Monthly annulus fluid volume added or removed; and
- The results of monitoring prescribed under LAC 43:XVII §3625.

## 11.2 WITHIN 30 DAYS

The results of the following will be reported to the Secretary within 30 days of the conclusion of activity:

- Periodic tests of mechanical integrity;
- Any well workover; and,
- Any other test of the injection well conducted by the permittee if required by the Secretary.

## 11.3 WITHIN 24 HOURS

The following occurrences will be reported to the Secretary within 24 hours:

- Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
- Any triggering of a shut-off system (i.e., down-hole or at the surface);
- Any failure to maintain mechanical integrity; or
- Any release of carbon dioxide to the atmosphere or biosphere (in compliance with the requirement at LAC 43:XVII §3625.A.8 for surface air/soil gas monitoring or other monitoring technologies, if required by the Secretary).

## 12 NOTIFICATIONS

GCS will notify the Secretary in writing 30 days in advance of the following activities:

- Any planned well workover;
- Any planned stimulation activities, other than stimulation for formation testing conducted under LAC 43:XVII §3621.A.9; and



45031 & 45032

— Any other planned test of the injection well conducted by the permittee.



**Table XII.1-1 Operating Conditions for MS CCS 1 and MS CCS 2**

Operating Parameters		MS CCS 1			MS CCS 2		
		Perforated Interval			Perforated Interval		
		1	2	3 (Upside)	1	2	3 (Upside)
Designed	Average Designed Surface Injection Pressure <sup>[1]</sup> (psig)	1,265	1,245	1,215	1,455	1,430	1,410
	Average Flowing Bottom-Hole Pressure <sup>[1]</sup> (psig)	4,640	4,534	4,345	4,582	4,470	4,283
	Average Design Annulus Pressure (psig)	1,415	1,395	1,365	1,605	1,580	1,560
Simulation Model	Completion Zone	Frio 5	Frio 4	Frio 0.5 & Frio 1	Frio 5	Frio 4	Frio 0.5 & Frio 1
	Completion Interval Elevation Corresponding to Pressures (ft TVD)	9,996 - 10,056	9,736 - 9,896	9,194 - 9,494	9,870 - 9,930	9,593 - 9,770	9,041 - 9,350
	Maximum Injection Rate (MMscf/day)	20	26	14	19	26	14
	Average Injection Rate (MMscf/day)	17	23	12	16.5	23	12
	Injection Well Yearly Rate (MMT/year)	0.28	0.37	0.19	0.27	0.37	0.19
	Injection Period (years)	17	13	6	17	13	6
	Total Injection Volume and/or Mass (MMT)	4.69	4.85	1.07	4.62	4.85	1.07
	Total Injection Volume and/or Mass (MMscf)	89,941	93,011	22,338	88,634	93,011	22,338
	Fracture Gradient (psi/ft)		0.85			0.85	
	Modeled Surface Injection Temperature (°F)		77			77	
	Modeled Surface Injection Pressure (psi)	1,972	1,952	1,917	2,143	2,064	2,103
	Modeled Maximum Bottom-Hole Injection Pressure (psi)	4,910	4,814	4,621	5,044	4,884	4,762
Reg	Regulatory Maximum Authorized Surface Injection Pressure (psig)	4,709	4,586	4,299	4,650	4,519	4,257
	Regulatory Maximum Authorized Bottom-Hole Pressure (90% of frac gradient)	7,647	7,448	7,003	7,551	7,339	6,916
	Annulus Pressure/Tubing Differential (psi)		150			150	

Note:

<sup>[1]</sup> Average Designed Surface Injection Pressure is based on surface equipment design modeling at pressure and temperature. Average Flowing Bottom-Hole Pressure is the corresponding calculated downhole pressure for this Average Designed Surface Injection Pressure.


**Table XII.1-2 Project Minerva's CO<sub>2</sub> Stream Compositions**

Component	Project Minerva Proposed Stream	Simulation Model Simplified Stream
<b>Carbon Dioxide (CO<sub>2</sub>)</b>	<b>&gt; 97% vol</b>	<b>&gt; 97% vol</b>
<b>Total non-condensable gases*</b>	<b>&lt; 3% vol</b>	
Oxygen (O <sub>2</sub> )	< 10 ppmv	
Methane (CH <sub>4</sub> )	< 1.5% vol	< 1.5% vol
Nitrogen (N <sub>2</sub> ), Argon (Ar), Hydrogen (H <sub>2</sub> ), Carbon Monoxide (CO), and Ethane (C <sub>2</sub> H <sub>6</sub> )	< 1.5% vol	< 1.5% vol (Nitrogen only, N <sub>2</sub> )
<b>Water (H<sub>2</sub>O)</b>	<b>&lt; 100 ppmv</b>	
<b>Hydrogen Sulfide (H<sub>2</sub>S)</b>	<b>&lt; 15 ppmv</b>	
<b>Mercury (Hg)</b>	<b>&lt; 1 ppbv</b>	



**APPENDIX XII-2**  
Operating Plan for  
Minerva South CCS No. 002



## TABLE OF CONTENTS

FACILITY INFORMATION .....	1
PROPOSED OPERATING PLAN FOR MS CCS 2 .....	1
1 INJECTION RATE AND PRESSURE .....	1
1.1 Injection Rate.....	1
1.2 Injection Pressure.....	1
2 CO <sub>2</sub> STREAM .....	2
2.1 CO <sub>2</sub> Volume .....	2
2.2 CO <sub>2</sub> Stream Characteristics .....	2
3 MECHANICAL INTEGRITY .....	2
3.1 Annulus Fluid and Pressure.....	2
3.2 Pressure Gauges .....	2
4 INJECTION WELL INSTRUMENTATION AND MONITORING SYSTEMS.....	3
4.1 Continuous Recording Devices .....	3
4.2 Corrosion Monitoring.....	3
4.3 Mechanical Integrity Monitoring .....	4
5 ALARMS AND EMERGENCY SHUTDOWN .....	4
6 WELLHEAD IDENTIFICATION AND PROTECTION .....	5
7 WELL WORKOVERS .....	5
7.1 Stimulation Program.....	5
8 CONTINGENCIES AND PREVENTIONS.....	5
8.1 Contingency Plans for Shut-In Or Well Failures .....	5
8.2 Precautions to Prevent Well Blowouts .....	6
9 EMERGENCY SHUTDOWN .....	6
9.1 Circumstances Under Which Injection Must Cease.....	6
9.2 Shutdown Response.....	7
10 RECORDKEEPING.....	7
11 REPORTING.....	8
11.1 Quarterly .....	8
11.2 Within 30 Days .....	9
11.3 Within 24 Hours .....	9
12 NOTIFICATIONS.....	9



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Well Locations:	Sec 3, T12S, R13W, Cameron Parish, Louisiana MS CCS 1 (NAD 1927) Surface: 30° 02' 34.10"N, 93° 40' 20.63"W Bottom-Hole: 30° 02' 34.10"N, 93° 40' 20.63"W MS CCS 2 (NAD 1927) Surface: 30° 02' 33.84"N, 93° 40' 20.48"W Bottom-Hole: 30° 02' 13.74"N, 93° 40' 42.07"W

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### 1 INJECTION RATE AND PRESSURE

#### 1.1 INJECTION RATE

Project Minerva utilizes a sequential completion strategy, starting with the bottom interval and progressing upwards. Targeted injection rates are set at 17 MMSCF/D in MS CCS 1 and 16.5 MMSCF/D in MS CCS 2 for the bottom interval (Interval 1) for 17 years and 23 MMSCF/D into the intermediate interval (Interval 2) of MS CCS 1 and MS CCS 2 for 13 years. The project will inject a combined average range of 0.547- 0.746 metric tons (MMT) of CO<sub>2</sub> per year over its 30-year lifespan, split between two injection wells, as defined in Table XII.2-1.

#### 1.2 INJECTION PRESSURE

Injection induced pressure will not exceed 90% of the fracture pressure of the zone. The bottom-hole pressures are significantly smaller than the estimated fracture pressure and induced seismicity pressure. The initial formation pressure is based on the most-likely initial formation pressure gradient of 0.457 psi/ft.

The most-likely value of the minimum horizontal stress gradient is assumed to be 0.85 psi/ft,



as provided in Section 2.5.1.2 (Total Minimum Horizontal Stress) of the Project Minerva Narrative. The depth of the deepest completion interval in MS CCS 2 is approximately 9,870 ft TVD, which calculates to a minimum horizontal stress of approximately 8,390 psia. Assuming a safety factor of 90%, this gives an estimate of the formation fracturing pressure to be approximately 7,551 psia at the same depth. This is a conservative estimate as it assumes no cohesion in the formation, i.e. the formation parts as soon as the effective minimum horizontal stress is less than zero. The induced seismicity pressure is estimated to be 9,870 psia at a depth of 9,870 ft TVDSS at the pressure gradient of 1 psi/ft.

## 2 CO<sub>2</sub> STREAM

### 2.1 CO<sub>2</sub> VOLUME

Project Minerva is designed to permanently store a total of 19.0 MMT, in the base case. This mass will be achieved by injecting at an average rate ranging from 0.547-0.746 MMT/yr for 30 years. Tables XII.2-1 provides a detailed breakdown of the injection rates for each injection interval of MS CCS 2.

### 2.2 CO<sub>2</sub> STREAM CHARACTERISTICS

Table XII.2-2 provides the proposed CO<sub>2</sub> stream specification for Project Minerva. This specification is designed to ensure safe operation of the project and ensure no-endangerment of the USDW. Project Minerva envisions sourcing CO<sub>2</sub> volumes from multiple sources of CO<sub>2</sub> from industrial facilities in Lake Charles industrial corridor in southwestern Louisiana and Beaumont industrial corridor in southeastern Texas and are likely to be higher purity CO<sub>2</sub> due to the lower cost of capture for such emissions. These sources have the ability to meet or exceed the proposed CO<sub>2</sub> specification. The reservoir simulation model fully accounts for the CO<sub>2</sub> specification.

## 3 MECHANICAL INTEGRITY

GCS will maintain mechanical integrity of the injection well at all times, except when doing well workovers, well maintenance, or well remedial work approved by the regulatory agency with authority over the well.

### 3.1 ANNULUS FLUID AND PRESSURE

The annulus between the tubing (OD: 4.5”) and long-string (ID: 8.535”) casing will be filled with >9.0 CaCl<sub>2</sub> inhibited brine with a non-corrosive fluid. Final chemical formulation and concentration will be defined with the fluids vendor selected for the project. GCS will maintain pressure on the annulus that exceeds the operating injection pressure presented in Table XII.2-1.

### 3.2 PRESSURE GAUGES

GCS will install pressure gauges on the wellhead that show pressure on the injection tubing and tubing-casing annulus. The digital or analog gauges will be designed to read in increments of 10 psig and will be properly calibrated and maintained in good working order.



The pressure valves onto which the pressure gauge is affixed will have one-half inch female fittings, or equivalent to meet required API wellhead or ASME pipe design requirements for safety.

## **4 INJECTION WELL INSTRUMENTATION AND MONITORING SYSTEMS**

### **4.1 CONTINUOUS RECORDING DEVICES**

GCS will install continuous recording devices on the injection well, and ensure they are used and maintained in proper working order. The devices will monitor surface injection or bottom-hole pressure; flow rate, volume and/or mass, and temperature of the carbon dioxide stream; tubing-casing annulus pressure and annulus fluid volume; any other data specified by the regulatory authority.

The continuous recordings will be digitally recorded, and the recording instrument will be weatherproof or housed in weatherproof enclosures if located in areas exposed to climatic conditions.

The Testing and Monitoring Plan (Attachment D, Section 4.0) provides additional information regarding the continuous monitoring details, location, equipment, accuracy, and frequency.

### **4.2 CORROSION MONITORING**

All components of MS CCS 2 that are in direct contact with the carbon dioxide stream and formation fluids in the Injection Zone will be constructed of noncorrosive materials, 25CRW-125 for 9 5/8" casing and 4 1/2" tubing.

The CO<sub>2</sub> stream will be routed through a loop installed in-parallel with the pipe at the surface facilities to monitor for corrosion of the injection wells. The loop will be constructed of 25Cr corrosion resistant alloy (CRA), matching the material of the 9 5/8" long string casing installed across the Injection and Confining Zones. While all efforts will be made to operate the corrosion loop at downhole temperatures, during detailed engineering an evaluation will be made to determine the practicality and ability to simulate well conditions. Final technology selection will be completed after detailed engineering.

Corrosion monitoring of the loops will be performed on a quarterly basis to inspect for loss of mass, thickness, cracking, pitting, and other signs of corrosion, and to ensure that the well components meet the minimum standards for material strength and performance set forth in LAC 43:XVII §3617.A.2. Quarterly inspections will be conducted by a Level 3 Non-Destructive Testing (NDT) and Non-Destructive Examination (NDE) certified inspectors and technologies, including but not limited to, Ultrasonic and Radiography equipment.

The Testing and Monitoring Plan (Attachment D, Section 5.0) provides additional information regarding monitoring, inspection, location, and frequency.



### 4.3 MECHANICAL INTEGRITY MONITORING

In accordance with LAC 43:XVII.3627.A.2, GCS will conduct mechanical integrity testing as follows:

- The long string casing, injecting tubing, and annular seal shall be tested by means of an approved pressure test with a liquid or gas
  - After initial well construction as part of the Pre-Operating requirements (See Attachment C)
  - At least once every 12 months witnessed by an agent with the UIC Program, and
  - After there has been a well workover involving the unseating or disturbing of the injection tubing or annular seal system of the packer;
- A pressure fall-off test shall be conducted upon completion of the well and every five years thereafter to monitor pressure buildup in the injection zone. More frequent testing may be required by the Secretary based on site-specific information;
- Temperature logging will be used as the primary test to demonstrate external integrity of the injection wells (LAC 43:XVII §3627.A.3.a-b,), details provided in the Testing and Monitoring Plan (Attachment D, Section 7.2.1);
- A Digital Temperature Sensing (DTS) fiber optic cable will be installed on the long-string of MS CCS 1 to provide continuous external mechanical integrity monitoring of the wellbore;
- A DTS mechanical integrity test (DTS MIT) will be performed as an alternative test at least once every 12 months to corroborate the data required from the Temperature logging, as described in the Testing and Monitoring Plan (Attachment D, Section 7.2.2). Once sufficient validation of the data is made, GCS will submit a request to the C&E Secretary to utilize the alternative method for external MIT demonstration;
- If supplemental testing is requested by the C&E Secretary (LAC 43:XVII §3627.A.4 and §3627.A.7), a casing inspection log shall be run to determine the presence or absence of corrosion in the long-string casing, Testing and Monitoring Plan (Attachment D, Section 7.2.3).

Except during workovers or routine maintenance, any well which is not operational shall conform to the mechanical integrity requirement of LAC 43:XVII.3621.A.3-4 and shall sustain a positive pressure on the annulus during the period of non-use. If GCS plans to take a well out of operation, a plan to assure the mechanical integrity of the well during non-use will be submitted to the Secretary.

## 5 ALARMS AND EMERGENCY SHUTDOWN

MS CCS 2 will be equipped with alarms and automatic surface shut-off valves or other mechanical devices that provide equivalent protection. The alarms will be integrated with the automatic shutdown system. The emergency shutdown systems will be fail-safe, and



GCS will function-test all critical systems of control and safety at least once every six months. This includes testing of alarms, test tripping of emergency shutdown valves ensuring their closure times are within design specifications, and ensuring the integrity of all electrical, pneumatic, and hydraulic circuits. Test dates and results will be documented and will be made available for inspection by an agent of the regulatory authority.

If a shutdown is triggered or a loss of mechanical integrity is discovered, GCS will immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, GCS will take action by immediately ceasing injection and notifying the regulatory authority within 24 hours of shutdown. GCS will submit a plan to restore and demonstrate mechanical integrity to the satisfaction of the regulatory authority prior to resuming injection. After demonstrating mechanical integrity, GCS will notify the regulatory authority when injection can be expected to resume.

## **6 WELLHEAD IDENTIFICATION AND PROTECTION**

GCS will install and maintain a protective barrier around the wellheads, piping, and above ground structures that may be vulnerable to physical or accidental damage by mobile equipment or trespassers. An identifying sign will be placed at the wellhead of the injection well and will include at a minimum the operator name, well name and number, well serial number, section-township-range, and any other information required by the regulatory authority. The sign will be of durable construction with all lettering kept in a legible condition.

## **7 WELL WORKOVERS**

GCS will submit a work permit request form (Form UIC-17, or its replacement) to the regulatory authority prior to performing: well remedial work, well maintenance or repair, well or injection formation stimulation, well plug and abandonment or temporary abandonment, any other test of the injection well conducted by GCS, or well work of any kind. GCS will not commence work without prior written authorization from the regulatory authority.

### **7.1 STIMULATION PROGRAM**

All stimulation activities will be approved by the regulatory authority prior to conducting the stimulation. GCS will carry out the Stimulation Program for MS CCS 2 in accordance with the plan provided in Appendix XI-2 of the Project Minerva Narrative.

## **8 CONTINGENCIES AND PREVENTIONS**

### **8.1 CONTINGENCY PLANS FOR SHUT-IN OR WELL FAILURES**

MS CCS 2 will be equipped with alarms integrated with an automatic shutdown system (LAC 43:XVII §3621.A.7.a-c). The injection well will be equipped with a shutdown valve actuated by any of the following pressure scenarios:



- High-pressure approaching the designated Maximum Authorized Surface Injection Pressure (MASIP);
- Low-pressure that could indicate a potential surface leak;
- High/low pressure indicated on the tubing/casing annulus. This shutdown valve is intended to stop the flow of CO<sub>2</sub> into the injection well in the event of 1) a tubing leak, or 2) a casing, packer, or wellhead leak.

If an alarm or shutdown is triggered, the cause of the alarm or shutdown will be immediately investigated to identify the origin of the shutdown. GCS would also:

- Immediately cease injection operations;
- Take necessary steps to determine the presence or absence of a leak; and
- Provide verbal notification to the Secretary within 24 hours.

If the alarm or shutdown is not related to mechanical integrity and the cause of the alarm or shutdown is corrected, injection operations will resume.

If the mechanical integrity of the well is in question, the well will remain out of service until mechanical integrity of the well is restored to the satisfaction of the Secretary and they approve resumption of injection operations.

## 8.2 PRECAUTIONS TO PREVENT WELL BLOWOUTS

Except at specific times as approved by the Secretary, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall follow procedures such as those below to ensure that a backflow or blowout does not occur:

- Limit the temperature and/or corrosivity of the injectate; and
- Develop procedures necessary to assure that pressure imbalances do not occur.

## 9 EMERGENCY SHUTDOWN

### 9.1 CIRCUMSTANCES UNDER WHICH INJECTION MUST CEASE

Injection shall cease when any of the following circumstances arises:

- Failure of the well to pass a mechanical integrity test;
- A loss of mechanical integrity during operation;
- The automatic alarm or automatic shut-off system is triggered;
- A significant unexpected change in the annulus or injection pressure;
- The Secretary determines that the well lacks mechanical integrity; or



- The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Secretary determines that injection should cease.

## 9.2 SHUTDOWN RESPONSE

If a shutdown is triggered or a loss of mechanical integrity is discovered, GCS will immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, GCS will take action by immediately ceasing injection and notifying the regulatory authority within 24 hours of shutdown in accordance with the Emergency and Remedial Response Plan (Attachment G).

GCS will submit a plan to restore and demonstrate mechanical integrity to the satisfaction of the regulatory authority prior to resuming injection. After demonstrating mechanical integrity, GCS will notify the regulatory authority when injection can be expected to resume.

## 10 RECORDKEEPING

Operations and monitoring records will be maintained, and written monitoring reports will be submitted periodically to the Secretary in accordance with the requirements outlined in LAC 43:XVII §3629.A. Regardless of whether the State of Louisiana has primary permit and enforcement authority (primacy) for Class VI wells, GCS will submit all required submittals, reports, and notifications under (LAC 43:XVII §3605, 3607, 3615, 3617, 3619, 3621, 3623, 3625, 3627, 3629, 3631, and 3633) to the USEPA in an electronic format approved by the USEPA.

In accordance with LAC 43:XVII §3625.B.3 and §3629.A.6, GCS will maintain accurate records of the following:

- All data collected under LAC 43:XVII §3607 and 3619 will be retained throughout the life of the geologic sequestration project and for 10 years following site closure;
- Data on the nature and composition of all injected fluids collected pursuant to LAC 43:XVII §3625.B.2.b shall be retained at least 3 years after site closure. The Secretary may require GCS to deliver the records to the Secretary at the conclusion of the retention period.
- Pursuant to LAC 43:XVII §3629.A.4 the following monitoring data shall be retained for at least 10 years after it is collected:
  - Data collected from continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;
  - Results of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion;
  - Data and analyses from monitoring of the groundwater quality and geochemical changes above the confining zone(s);



- Results of pressure fall-off tests;
  - Indirect and direct testing and monitoring data to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure;
  - If required, data from surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW; and
  - Any additional monitoring data, as required by the Secretary, necessary to support, upgrade, and improve computational modeling of the area of review evaluation;
- Pursuant to LAC 43:XVII §3625.B.3 the following monitoring information shall recorded:
- the date, exact place, and time of sampling or measurements;
  - the individual(s) who performed the sampling or measurements;
  - the date(s) analyses were performed;
  - the individual(s) who performed the analyses;
  - the analytical techniques or methods used; and
  - the results of such analyses.
- Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at LAC 43:XVII §3633.A.6 and 3633.A.8 shall be retained for at least 10 years following site closure; and
- Records related to AOR modeling inputs and data used to support area of review reevaluations; data and reports enumerated in the previous subsection (§3629.A.6); well closure; site closure; and any records gathered during the post-injection site care period for at least 10 years following site closure.

The Secretary has authority to require GCS to retain any records required in LAC 43:XVII §3629.A.6 for longer than 10 years after site closure.

## 11 REPORTING

### 11.1 QUARTERLY

Quarterly reports, as specified in LAC 43:XVII.3629.A, will be submitted within thirty (30) days following the end of each 6-month period for which the report is being submitted. The reports will include the following information:

- Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;



- Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;
- A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;
- A description of any event which triggers a shut-off device required pursuant to LAC 43:XVII.3621.A.6 and the response taken;
- The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;
- Monthly annulus fluid volume added or removed; and
- The results of monitoring prescribed under LAC 43:XVII.3625.

## 11.2 WITHIN 30 DAYS

The results of the following will be reported to the Secretary within 30 days of the conclusion of activity:

- Periodic tests of mechanical integrity;
- Any well workover; and,
- Any other test of the injection well conducted by the permittee if required by the Secretary.

## 11.3 WITHIN 24 HOURS

The following occurrences will be reported to the Secretary within 24 hours:

- Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
- Any triggering of a shut-off system (i.e., down-hole or at the surface);
- Any failure to maintain mechanical integrity; or
- Any release of carbon dioxide to the atmosphere or biosphere (in compliance with the requirement at LAC 43:XVII.3625.A.8 for surface air/soil gas monitoring or other monitoring technologies, if required by the Secretary).

## 12 NOTIFICATIONS

GCS will notify the Secretary in writing 30 days in advance of the following activities:

- Any planned well workover;
- Any planned stimulation activities, other than stimulation for formation testing conducted under LAC 43:XVII.3621.A.9; and



45031 & 45032

— Any other planned test of the injection well conducted by the permittee.



**Table XII.2-1 Operating Conditions for MS CCS 1 and MS CCS 2**

Operating Parameters		MS CCS 1			MS CCS 2		
		Perforated Interval			Perforated Interval		
		1	2	3 (Upside)	1	2	3 (Upside)
Designed	Average Designed Surface Injection Pressure <sup>[1]</sup> (psig)	1,265	1,245	1,215	1,455	1,430	1,410
	Average Flowing Bottom-Hole Pressure <sup>[1]</sup> (psig)	4,640	4,534	4,345	4,582	4,470	4,283
	Average Design Annulus Pressure (psig)	1,415	1,395	1,365	1,605	1,580	1,560
Simulation Model	Completion Zone	Frio 5	Frio 4	Frio 0.5 & Frio 1	Frio 5	Frio 4	Frio 0.5 & Frio 1
	Completion Interval Elevation Corresponding to Pressures (ft TVD)	9,996 - 10,056	9,736 - 9,896	9,194 - 9,494	9,870 - 9,930	9,593 - 9,770	9,041 - 9,350
	Maximum Injection Rate (MMscf/day)	20	26	14	19	26	14
	Average Injection Rate (MMscf/day)	17	23	12	16.5	23	12
	Injection Well Yearly Rate (MMT/year)	0.28	0.37	0.19	0.27	0.37	0.19
	Injection Period (years)	17	13	6	17	13	6
	Total Injection Volume and/or Mass (MMT)	4.69	4.85	1.07	4.62	4.85	1.07
	Total Injection Volume and/or Mass (MMscf)	89,941	93,011	22,338	88,634	93,011	22,338
	Fracture Gradient (psi/ft)		0.85			0.85	
	Modeled Surface Injection Temperature (°F)		77			77	
	Modeled Surface Injection Pressure (psi)	1,972	1,952	1,917	2,143	2,064	2,103
	Modeled Maximum Bottom-Hole Injection Pressure (psi)	4,910	4,814	4,621	5,044	4,884	4,762
Reg	Regulatory Maximum Authorized Surface Injection Pressure (psig)	4,709	4,586	4,299	4,650	4,519	4,257
	Regulatory Maximum Authorized Bottom-Hole Pressure (90% of frac gradient)	7,647	7,448	7,003	7,551	7,339	6,916
	Annulus Pressure/Tubing Differential (psi)		150			150	

Note:

<sup>[1]</sup> Average Designed Surface Injection Pressure is based on surface equipment design modeling at pressure and temperature. Average Flowing Bottom-Hole Pressure is the corresponding calculated downhole pressure for this Average Designed Surface Injection Pressure.


**Table XII.2-2 Project Minerva's CO<sub>2</sub> Stream Compositions**

Component	Project Minerva Proposed Stream	Simulation Model Simplified Stream
<b>Carbon Dioxide (CO<sub>2</sub>)</b>	<b>&gt; 97% vol</b>	<b>&gt; 97% vol</b>
<b>Total non-condensable gases*</b>	<b>&lt; 3% vol</b>	
Oxygen (O <sub>2</sub> )	< 10 ppmv	
Methane (CH <sub>4</sub> )	< 1.5% vol	< 1.5% vol
Nitrogen (N <sub>2</sub> ), Argon (Ar), Hydrogen (H <sub>2</sub> ), Carbon Monoxide (CO), and Ethane (C <sub>2</sub> H <sub>6</sub> )	< 1.5% vol	< 1.5% vol (Nitrogen only, N <sub>2</sub> )
<b>Water (H<sub>2</sub>O)</b>	<b>&lt; 100 ppmv</b>	
<b>Hydrogen Sulfide (H<sub>2</sub>S)</b>	<b>&lt; 15 ppmv</b>	
<b>Mercury (Hg)</b>	<b>&lt; 1 ppbv</b>	