ATTACHMENT G –
TESTING AND MONITORING PLAN

GULF COAST SEQUESTRATION
PROJECT MINERVA

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FACILITY INFORMATION

Facility name: Project Minerva
Injector Well Nos. 1 – 4

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Well Locations: [redacted]

1.0 INTRODUCTION

This Testing and Monitoring Plan describes how Gulf Coast Sequestration ("GCS") will monitor the Project Minerva site pursuant to 40 CFR 146.90 and LAC 43:XVII §3625.A. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to underground sources of drinking water ("USDW"), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of CO_2 within the storage zone to support Area of Review ("AoR") reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan 40 CFR 146.94(a) (LAC 43:XVII §3623.A.1)

2.0 TESTING AND MONITORING STRATEGY

This Testing and Monitoring Plan for Project Minerva site includes an analysis of the injected CO_2, periodic testing of the injection well, a corrosion-monitoring plan for the CO_2 injection well components, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor for potential movement of CO_2 outside of the storage reservoir. As such, this plan simultaneously meets the permit requirements for three required monitoring activities:

1. Corrosion monitoring and prevention (40 CFR 146.90(c), LAC 43:XVII §3625.A.3);
2. Surface leak detection and monitoring (40 CFR 146.89(a), LAC 43:XVII §3627.A.1); and
3. Subsurface leak detection and monitoring (40 CFR 146.90(d), LAC 43:XVII §3625.A.4).

A combination of the above monitoring efforts will be used to verify that the geologic storage project is operating as permitted and is protecting the USDW. A regular assessment and adaptation of the monitoring program (i.e., a minimum of every 5 years) will be conducted to ensure that it remains appropriate for the site and is adequately tracking the injected CO_2, thereby providing an accurate assessment of the performance of the surface/subsurface equipment and subsurface storage complex containing the stored CO_2. If needed, alterations to the monitoring program (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by United States Environmental Protection Agency (USEPA) or the Louisiana Department of Natural Resources (LDNR), when Class VI primacy is granted. Results of pertinent analyses conducted as part of the monitoring program will be compiled and repeated, as required. An additional goal of this Testing and Monitoring Plan is to establish pre-injection baseline data for: (i) soil gas, (ii) shallow groundwater formations (the Chicot Aquifer System), and (iii) the first porous unit above the primary confining zone within the AoR (Miocene interval).

The Testing and Monitoring Plan considers the following site-specific parameters:

1. The Injection Zone (upper Frio Formation) has been divided into 11 regionally correlated geological sequences (alternating sandstone and mudstone intervals). Many of these sandstones function as separate flow units separated by intra-Frio flow barriers or baffles (mudstones). The thickness of the upper Frio Formation ranges from 800 to 2,300 ft TVDSS.
2. The performance of the upper Frio Formation in accepting CO_2 injection is well known. The upper Frio Formation has been used regionally as a target for Underground Injection Control ("UIC") Class I injection, has hosted an extensively monitored DOE-funded test injection project in Liberty County,

Texas, and has received CO_2 for CO_2 EOR in multiple fields. Two Frio injection sites at Hastings field and West Ranch field received anthropogenic CO_2 and have been monitored as part of DOE-funded programs supporting CCUS projects.

3. The performance of the shale-rich Anahuac Formation as a confining unit is well known because a) it retains hydrocarbons regionally and b) coring and testing program conducted as part of the UIC Class I program have documented the quality of this thick, low permeability mudstone. [redacted] Vertical leakage through the Anahuac Formation along faults or fractures has been considered and is not believed to be a credible leakage pathway.

4. The Miocene interval overlying the Anahuac Formation is composed of >7,000 ft TVDSS of highly transmissive sandstones, interbedded regional mudstone seals and local mudstone baffles. Regionally, the Miocene contains hydrocarbons and is used for Class I injection in both Louisiana and Texas. [redacted]

5. The Chicot aquifer groundwater in the AoR is hosted in the transmissive and multi-layered Beaumont Formation, which is regionally well known as a groundwater resource. However, locally it is sparsely used. Locally saline waters may be present in the Chicot aquifer because of natural salinization near salt domes or as a result of early oil and gas production activities that failed to protect USDWs. In addition, the Chicot aquifer system is locally charged with both biogenic and thermogenic methane. The monitoring program will geochemically characterize the initial condition of this aquifer system so that any changes resulting from the unlikely event of CO_2 or injection formation brine leaking from the injection zone. [redacted]

6. Natural seismicity in the area is low and induced seismicity risk is also low because of high transmissivity and lack of brittle rocks within, above, or below the Injection Zone. Previous measurements of seismicity in Gulf Coast projects have not detected events resulting from injection. Therefore, seismicity will be monitored via public networks for change in frequency. Only if a change in frequency occurs will monitoring of local events be undertaken. Bottom seal is provided by thick mudstones of the Mid Frio (Hackberry Shale). Brittle basement is greater than 6 miles (10 km) below the Injection Zone and is not involved in injection.

7. GCS has set forth a robust proposal for characterizing surface and groundwater monitoring over the life of the project. The primary objective of the proposed surface and groundwater sampling and investigation workplan is to evaluate baseline conditions of surface water and ecological conditions within the AoR. [redacted]

[redacted]

2.1 MONITORING NETWORK

The monitoring network is composed of the following elements, shown on Figures G.2.1-1, G.2.1-2 and G.2.1-3.

1. Monitoring and sampling at the pipeline handoff to the injection site will determine the key parameters of mass and purity of CO_2 needed for accounting of mass injected and modeling of the subsurface response to injection.
2. Monitoring at injection wells will ensure that the wells are performing as intended to deliver the CO_2 to the injection zones and measure the pressure response, a key model match parameter. Downhole pressure gauges and injection logging in the four injection wells will be used to assess within-plume reservoir response to injection.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

9. Surface monitoring and protection will be accomplished using an ecosystem and land-use survey. This will be based on aerial image analysis, conducted across the AoR. The analysis will establish a pre-injection baseline of surface conditions. Selected sampling stations will be located in areas that represent the diversity of ecosystems including disturbed areas and wetlands. Fluids to be assessed at each site include shallow groundwater, soil gases, and surface water.

2.2 QUALITY ASSURANCE PROCEDURES

A Quality Assurance and Surveillance Plan ("QASP") for all testing and monitoring activities, required pursuant to 40 CFR 146.90(k) and LAC43: XVII §3625.A.11, is provided in the QASP.

2.3 REPORTING PROCEDURES

GCS will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91 and LAC 43:XVII §3629.A.

3.0 PROJECT RISK ASSESSMENT

Monitoring is systematically designed to reduce project risk. This section outlines the site-specific risks and describes how the monitoring plan will systematically reduce them. Three prospective risk categories are identified:

3.1 RISK CATEGORY 1: A DEFICIENT WELL WITHIN THE CO_2 PLUME OR PRESSURE FRONT

[redacted]

[redacted]. The process for the corrective action review is provided, in Attachment B (Area of Review and Corrective Action Plan). In this analysis, each artificial penetration, well status, construction, drilling materials, and barriers to vertical fluid migration were evaluated to determine if the proposed injection would endanger the USDW.

3.2 RISK CATEGORY 2: THE CO_2 PLUME OR AOR MIGRATES IN A PREFERENTIAL PATHWAY NOT PREDICTED THROUGH MODELLING

Injection for the project is placed in the syncline axis to maximize isolation of the CO_2 from three surrounding salt domes and associated oil and gas wellbores. Modelling of the CO_2 plume and associated pressure rise have been modeled with using publicly available data and the CO_2 plume and pressure front does not reach the areas of dense oil and gas penetrations. [redacted].

3.3 RISK CATEGORY 3: INDUCED SEISMICITY

Calculation of risk for this project shows that this risk is negligible - see Section 2.3.3 (Seismic Risk Analysis) of the Class VI Permit Application Narrative (submitted separately). The best practice in this situation is to monitor seismic magnitude and frequency via public networks to ensure that no unexpected change is occurring. Seismic magnitude and frequency monitoring will be paired with plume migration monitoring.

3.4 DESIGN OF THE MONITORING NETWORK TO ACHIEVE RISK MANAGEMENT

The monitoring approaches selected manage the risks described in the previous section and are described for each of the categories listed above.

3.4.1 Risk category 1: A deficient well in AoR

[redacted] Monitoring of the injection zone will be carried out by two lines of protection, a main barrier and a near surface surveillance program.

The main barrier used to detect out-of-zone migration along a deficient well is above-zone pressure monitoring. [redacted] Pressure-based AZ monitoring is widely used for protection via monitoring in settings including gas storage reservoirs and was tested for CO_2 storage projects at the SECARB Early Test at Cranfield Field, Mississippi. Additional storage projects using pressure based AZ are associated with EOR at Hastings field in Alvin, Texas and West Ranch field in Vanderbilt, Texas.

Secondary to the AZ, a USDW surveillance program has been designed to be deployed to provide assurance that no near-well leakage is occurring. See in #8 of Section 2.1 (Monitoring Network). Surface monitoring and protection will be accomplished using an ecosystem and land-use survey. The ecosystem monitoring program is described in #9 of Section 2.1 (Monitoring Network).

3.4.2 Risk category 2: CO_2 plume or AoR becomes larger than the modeled AoR

The extent of plume migration prior to stabilization and the extent of elevated pressure such that endangerment of USDW could occur have been modeled using publicly available data as outlined in the site characterization section submitted separately. If this was to occur, the CO_2 or larger AoR could encounter wells or faults that have not been evaluated to determine that they are isolating, resulting in a leakage signal as in Risk Category 1, but in areas outside of the modeled AoR. Monitoring will be used to increase the confidence of modeled outcomes and avoid the potential damage that could occur in the unlikely event the CO_2 plume or AoR becomes larger than modeled. Monitoring AoR extent includes three components: 1) seismically monitored plume movement and extent, 2) monitoring of the increased pressure, and 3) baseline profiles and threshold analysis based on a region-wide conductivity survey that extends into areas of dense existing penetrations and baseline monitoring of geochemical data. This monitoring will meet the expectations of plume and pressure tracking and be conducted at intervals during the injection and PISC period.

Time-lapse seismic measurements of the CO_2 plume will act as the main confirmation that the CO_2 is migrating as predicted by the modeling. [redacted]

[redacted]

[redacted]

Past oilfield practices may also have added increased local salinity. The planned conductivity survey will map this pre-injection salinity and any anomalies. A repeat conductivity survey will show that the injection has not elevated salinity in the USDW in these areas.

3.4.3 Risk category 3: Induced seismicity as a result of injection

The frequency and magnitude of local microseismic events can be used to forecast the likelihood of felt or damaging earthquakes. A single installed directional microseismic sensor will confirm that injection into the upper Frio Formation in this location has no detectable impact on seismicity in greater than magnitude 2.

4.0 CARBON DIOXIDE STREAM ANALYSIS

Prior to injection, GCS will determine the chemical and physical characteristics of the CO_2 stream using appropriate analytical methods. An example of the types of chemical composition data that will be generated and compiled is shown in Table G.4.0-1; and the physical characteristics of interest include density and viscosity.

4.1 SAMPLING LOCATION, EQUIPMENT, AND ACCURACY

CO_2 stream sampling will be conducted for all four injection wells using a gas chromatography machine that will measure CO_2 composition at the storage facility transfer point.

4.2 SAMPLING FREQUENCY

CO_2 stream sampling will be conducted at a minimum every month. Additional sampling will be conducted when known changes to the injected stream occur (i.e., source changes and/or additions/deletions to the existing stream). Density measurements at the mass flow meter greater than normal variability and not correlated to thermal variations will trigger sampling. The isotopic composition of carbon in CO_2 ($\delta C^{12}/C^{13}$ ratio and C^{14}) will be measured once and repeated only if new sources are added.

4.3 ANALYTICAL PARAMETERS

According to the requirements of EPA 40 CFR 146.90 and LAC 43:XVII §3625.A of the Class VI UIC Regulation, analysis of the CO_2 stream is required with sufficient frequency to provide data representative of its chemical and physical characteristics. Based on the anticipated composition of the CO_2 stream, a list of parameters was identified for analysis Table G.4.0-1. Samples of the CO_2 stream will be collected quarterly for chemical analysis. Analytical techniques and laboratory methods will be used to determine the chemical and physical characteristics of the CO_2 stream described Attachment H – Quality Assurance and Surveillance Plan, Section 16. Analytical methods will abide by the International Organization for Standardization (ISO), 2020.

4.4 SAMPLING METHODS

Grab samples of the CO_2 stream will be obtained for analysis of gases and water moisture (Table G.4.0-1). Samples will be collected from the CO_2 pipeline at a location where the flow is representative of injection conditions. These grab samples will be obtained using laboratory approved sampling cylinders to collect and transport the samples. Stainless steel tubing or equivalent pressure hoses will be connected to a designated sampling port, with a regulator to reduce the pressure of the CO_2 to approximately 250 psi so that the CO_2 is in the gaseous state when collected rather than a supercritical state to meet the requirements for shipment of compressed gases (CFR § 173.301[a][8]). Sample cylinders will be purged during sample collection to remove laboratory-added helium gas and ensure a representative sample.

4.5 ACCREDITED LABORATORY/CHAIN OF CUSTODY AND ANALYSIS PROCEDURES

Samples will be analyzed by a LELAP laboratory. LELAP is the program responsible for assessing and accrediting environmental laboratories that generate data that is submitted directly or indirectly to the Department of Environmental Quality. LELAP also assesses and accredits laboratories that generate data for the Department of Natural Resources with regards to Method Manual 29B. LELAP monitors laboratories to ensure compliance with state regulation and national standards. LELAP maintains a database that includes contact information, physical location, and matrix/method/analytes for each accredited laboratory. LELAP is one of 14 National Environmental Laboratory Accreditation Program (NELAP) recognized Accreditation Bodies.

5.0 CONTINUOUS RECORDING OF OPERATIONAL PARAMETERS

GCS will ensure operation of continuous recording devices and alarms and automatic shut-off systems as required by 40 CFR §146.88(e) and LAC 43: XVII §3621.A.6 through preventive maintenance (PM) and corrective maintenance (CM) program. GCS's PM program includes semi-annual testing of alarms and shut-off systems to confirm proper functionality and annual recalibration of continuous surface recording devices. GCS's CM program requires that any device that does not perform as expected during operation, testing, or recalibration is repaired or replaced. A record of test dates and results will be kept and maintained by the site operator until project completion and will be available to USEPA or LDNR upon request.

For all data streams collected during continuous monitoring, the transmitter sends data to a hard wired or wireless communications system that has both a battery backup and data storage backup for periods of downtime from the electrical grid or cell towers. The following sections describe the details of continuous recording of operational parameters in each location. Continuous injection well monitoring parameters also include annular pressure, wellhead pressure and temperature, injection rate, and bottom-hole pressure and temperature.

5.1 MONITORING LOCATION, EQUIPMENT, ACCURACY AND FREQUENCY

[redacted]

Project Minerva will use a mass flow meter to measure CO_2 mass delivered to the project at the transfer point from the pipeline to the project. Calibration will be conducted following the manufactures instructions and reported.

Additional flow meters will be installed on flow lines prior to each well to record CO_2 volume and temperature which will serve to guide the allocation of the CO_2 on a per well basis. Calibration will be conducted following the manufactures instructions and reported.

The following equipment/meter types will be used to facilitate the required monitoring requirements:

Injection pressure

- Proposed equipment: pressure transmitter
- Expected accuracy: Rosemount brand (or similar) – example accuracy is ± 0.04% reference accuracy resulting in ± 0.15% total operating performance; Stability (5-yr): ± 0.125%

Temperature

- Proposed equipment: temperature transmitter
- Expected accuracy: Rosemount brand (or similar) – example accuracy is ± 0.02% of span D/A Accuracy, RTD Stability: ± 0.25% or 0.25 °C, whichever is greater for years

CO_2 Rate and Volume

- Proposed equipment: Mass flow computer, senior orifice meter with either a mass flow computer or Coriolis meter
- Expected accuracy: Orifice meter - Differential Absolute Pressure: ± 0.05% of span (for spans between 10% and 90% of Upper Range Limit (URL); Digital Output (spans < 10% URL): ± (0.005) x (URL/Span)% of Span; Long Term Drift Stability: ± 0.05% of URL per year over 5 years; Temperature: ± 0.15°C (±0.27 °F) (not including RTD uncertainties). Coriolis meter – mass flow accuracy: 0.1% of rate ± (zero offset/mass flow rate) x 100%; repeatability 0.075% within the range of 10:1 of full-scale (FS) and 0.5% within the range of 100:1 of FS; rangeability up to 100:1

Annulus pressure

- Proposed equipment: ABB absolute pressure instrumentation
- Expected accuracy: Base accuracy: ± 0.1 %

Annulus fluid volume

The annular fluid volume is a fixed value rather than dynamic (that would require a meter) and will be calculated by using the following formula:

$$\text{Annular capacity in bbl/ft} = (Dh2 - Dp2) \div 1029.4$$

Where;
Dh (Drill Hole) in inch
Dp (Drill Pipe) in inch

The calculated volume is based on the inside diameter of wellbore casing and outside diameter of tubing string above the packers set in the wellbore.

5.2 MONITORING DETAILS

The mass flow meter will be protected against damage from lightning strikes.

Each well will be completed with equipment needed to 1) account for mass and pressure as inputs to fluid flow modeling to validate AoR predictions and 2) assure well integrity is maintained.

Wellhead pressure and temperature gauges will be installed to detect changes and record changes in tubing pressure filled with CO_2 and the casing-tubing anulus (filled with corrosion-inhibited fluid). Replenishment of corrosion-inhibited fluid will occur as needed, and the amounts added will be recorded. A more-rapid-than-normal change in casing-tubing anulus pressure will trigger shut-in of injection and inspection of well components until failure is identified.

Downhole quartz pressure gages on wireline readout will provide needed input to models and serve as opportunities for additional calibration of fluid flow models during injection fall-off tests and as injection is started at each injection well. Downhole pressure monitoring protects the project against over-injection as the near well environment is cooled and CO_2 becomes denser. The gauge location will connected to tubing above the packer where the gauge is protected by corrosion inhibited fluid with a pass though into the tubing. Pressure gauges will be calibrated according to manufacturer's instructions and corrected for drift by comparison to tubing deployed gauges during MIT (mechanical integrity testing).

Wireline logging to assess the injection profile will be conducted at a minimum six months and two years after the start of injection at each well to assess which zones are being used by CO_2 and input this into models. A commercial vendor will be selected to conduct this logging using any of the standard techniques. If the injection profile is not optimum, this log provides input to correct the strategy.

[redacted]

[redacted]

[redacted]

6.0 CORROSION MONITORING

The purpose of the Corrosion Monitoring and Prevention Plan is to monitor the corrosion of injection well components during the operational phase of the project to ensure that the well will meet the minimum standards for material strength and performance. To meet the requirements of 40 CFR 146.90(c) (LAC 43:XVII §3625.A.3), GCS will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

GCS will ensure safe and reliable operations of injection well components through a Corrosion Prevention and Monitoring Plan. Based on design assumptions for carbon dioxide composition, water chemistry, and metallurgy selections for tubing and casing strings, downhole corrosion of significance is not anticipated. An additional layer of protection for GCS's operational corrosion prevention will be carbon dioxide sampling and analysis to detect a change in composition of the fluid, as described in the QASP. GCS will implement a mechanical integrity program to investigate and mitigate any potential damage mechanisms before a pressure boundary failure occurs. To provide operational assurance that downhole corrosion, if occurring, would be detected early, GCS will install corrosion coupons, made of the same material(s) as the tubing and casing, in the surface flowline. Pursuant to 40 CFR 146.90(c) (LAC 43: XVII §3625.A.3).

GCS will mitigate identified threats through changes in operating parameters and/or addition of corrosion inhibitors, as warranted.

Over the lifetime of the project, corrosion treating chemicals may be injected into the CO_2 stream based on the corrosion monitoring results. The specific corrosion inhibitor injected will be compatible with all equipment used and the reservoir that will come in contact with the CO_2 stream throughout the project's lifetime. Periodic fluid sampling will be conducted at critical points in the system to determine the corrosion inhibitor's concentration and confirm that it is present at sufficient level, but not more than what is needed, to prevent corrosion.

6.1 MONITORING LOCATION AND FREQUENCY

Analyzing coupons of the well construction materials used in the well casing and tubing (and any other well parts in contact with CO_2) and inspecting the materials in the coupons for loss of mass, thickness, cracking, pitting, and other signs of corrosion. Loop and coupon details to be specified as part of pipeline and well design. These tests will be performed by GCS personnel or approved 3rd party on a quarterly calendar basis starting at the end of the first quarter month (March, June, September, December) following authorization and start-up of injection.

6.2 SAMPLE DESCRIPTION

When coupon inspection is conducted, they will be assessed using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens by GCS personnel or approved 3rd party. This ASTM process includes visually inspecting the coupons for evidence of corrosion (e.g., discoloration, pitting), measuring the weight and size (thickness, width, length) of the coupons, and calculating the corrosion rate based on weight loss during the exposure period divided by the duration (i.e., weight loss method).

6.3 MONITORING DETAILS

Per 40 CFR 146.90 (LAC 43:XVII §3625.A), GCS will run a casing inspection log (internal and external) to determine the presence or absence of corrosion in the longstring casing when the tubing is pulled from the well. The log(s) will be compared to those run during construction of the well (40 CFR 146.87, LAC 43:XVII §3617). Additional inspection logging may be performed should the coupons show excessive corrosion in excess of design-life criteria.

Alternative testing other than those listed above may be conducted, with the written approval of the Administrator. To obtain approval for alternative testing, GCS will submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use.

7.0 USDW MONITORING

To meet the requirements of 40 CFR 146.90(d) (LAC 43:XVII §3625.A.4), GCS will monitor the lower-most USDW of the Chicot Formation within the AoR. The following sections detail the monitoring methodology. Please refer to Figure G.2.1-1.

7.1 MONITORING LOCATION AND FREQUENCY

[redacted]

The goal of USDW groundwater monitoring is to develop a strategy to detect either brine or CO_2 leakage from depth into the aquifer, should it occur, using a process known as attribution of signal. This is not simple because many factors are expected to impact groundwater quality in this project area over the coming decades, including change in water levels related to sea level change and climate changes, changes in water production in offsite industrial areas, gradual natural mitigation and dilution of likely past oilfield water contamination events, natural migration of deep basin brines toward the surface in response to basin compaction, change in freshwater chemistry related to salt dissolution at salt domes, and land use changes. The same techniques will be used, if needed, to quantify leakage, assess impacts and validate remediation.

Attribution requires:

1. Characterization of injected fluids described in Section 5.0 (Carbon Dioxide Stream Analysis)
2. Characterization of fluids in the Injection Zone
3. Characterization of the ambient areal and seasonal variability of the lowermost USDW (described in this section)

Table G.7.1-2 shows representative diagnostic analytes to be evaluated.

[redacted]

Six USDW monitor wells will be drilled and completed to sample the Chicot Aquifer, the lowermost USDW. All wells will be drilled on GCS controlled land and have been assessed for wellsite access. The preliminary location of these wells have been mapped on Figure G.2.1-1. These wells fall into two location types: injection site specific monitoring wells and up-dip monitoring wells.

7.1.1 Injection Site Specific USDW Monitoring Wells

[redacted]

- [redacted]
- [redacted]
- [redacted]

7.1.2 Up-dip sentinel USDW monitoring wells

[redacted]

- [redacted]
- [redacted]
- [redacted]

7.2 WELL CONSTRUCTION

[redacted]

7.3 FREQUENCY

[redacted]

[redacted]

[redacted]

7.4 SAMPLING METHODS

Water samples will be collected from the lowermost USDW monitoring wells according to EPA method SESDPROC-301-R4 after purging three well volumes with a pump. Temperature, pH, specific conductivity, and dissolved oxygen and temperature will be measured in the field. Samples for isotopic analysis of DIC will be collected in 100-ml amber glass bottles with minimized headspace, and one drop of biocide (benzalkonium chloride) to eliminate biologic alteration of the sample. Samples will be immediately stored on ice and mailed overnight to a contracted laboratory for analysis of analytes listed in Table G.7.1-2. All samples will be filtered in the field with a 0.45μm filter. Conditions during groundwater sampling will be recorded in the field.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. The sample container will be sealed and sent to an authorized laboratory.

7.5 ACCREDITED LABORATORY/CHAIN OF CUSTODY AND ANALYSIS PROCEDURES

Samples will be analyzed by a LELAP laboratory. LELAP is the program responsible for assessing and accrediting environmental laboratories that generate data that is submitted directly or indirectly to the Department of Environmental Quality. LELAP also assesses and accredits laboratories that generate data for the Department of Natural Resources with regards to Method Manual 29B. LELAP monitors laboratories to ensure compliance with state regulation and national standards. LELAP maintains a database that includes contact information, physical location, and matrix/method/analytes for each accredited laboratory. LELAP is one of 14 National Environmental Laboratory Accreditation Program (NELAP) recognized Accreditation Bodies.

8.0 ABOVE ZONE (AZ) MONITORING

To meet the requirements of 40 CFR 146.90(d) (LAC 43:XVII §3625.A.4), GCS will monitor the Lower Miocene sands above the Confining Zone (Anahuac Formation) within the AoR. [redacted]

[redacted]

[redacted]

- [redacted]

[redacted]

8.1 MONITORING LOCATION AND FREQUENCY

[redacted]

8.2 SAMPLING METHODS

Deep brine sampling protocols are needed and all gases, not just hydrocarbons will be assessed. Methods are 1) Purge the casing volume to bring fresh fluids that have not reacted with casing and tubing to the sample point, 2) Deploy commercial downhole sampler on slickline to collect a fluid sample at pressure and then close to retain gas phases as sample is transported to the surface, 3) Conserve gas volumes as samples are stepped to atmospheric pressure for shipping and analysis, 4) Filter and conserve samples following protocols for brine sampling. All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. The sample container will be sealed and sent to an authorized laboratory.

If an anomalous pressure signal is detected, head spaced gas analysis plus pressure transient testing will be sufficient to detect any CO_2 leakage. Laboratory to be used/chain of custody and analysis procedures.

8.3 ACCREDITED LABORATORY/CHAIN OF CUSTODY AND ANALYSIS PROCEDURES

Samples will be analyzed by a LELAP laboratory. LELAP is the program responsible for assessing and accrediting environmental laboratories that generate data that is submitted directly or indirectly to the Department of Environmental Quality. LELAP also assesses and accredits laboratories that generate data for the Department of Natural Resources with regards to Method Manual 29B. LELAP monitors laboratories to ensure compliance with state regulation and national standards. LELAP maintains a database that includes contact information, physical location, and matrix/method/analytes for each accredited laboratory. LELAP is one of 14 National Environmental Laboratory Accreditation Program (NELAP) recognized Accreditation Bodies.

9.0 EXTERNAL MECHANICAL INTEGRITY TESTING ("MIT")

GCS will conduct at a minimum a temperature survey, additional tests are presented in Table G.9.0-1, periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90.

9.1 TESTING LOCATION AND FREQUENCY

GCS will perform an annual external mechanical integrity log on each injection well. Preferred testing will be performed using a temperature survey. The principal requirement for running temperature logs is that the well be shut-in long enough so that temperature effects related to well construction can dissipate, leaving a relatively simple temperature profile. Experience has shown that 36 hours is usually sufficient for the shut-in time period. Temperature survey data will be developed from the optical fiber attached to each injection well long-string casing.

Testing will be scheduled to be performed on an annual basis, within ± 45 days of the prior years' test. GCS will notify the Director ahead of testing should a testing event fall outside of the ± 45-day window.

9.2 TESTING DETAILS

Using temperature survey data from the optical fiber attached to each injection well long-string casing in each injection well is the simplest and preferred testing methodology for the demonstration of external integrity. Data from the optical fiber will be collected starting at cessation of injection and then accrued at increasing time intervals out to approximately 36 hours of shut in.

Subsequent temperature surveys will be compared to the baseline and prior surveys in each injection well.

Unresolved temperature anomalies that cannot be explained, may be an indication mechanical integrity failure. In such a case, additional logging will be conducted to show whether a loss of mechanical integrity is occurring in that injection well. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the Director may be required to further define the nature of the fluid movement.

10.0 PRESSURE FALL-OFF TESTING

To meet the requirements of 40 CFR 146.90(f) (LAC 43:XVII §3625.A.6), GCS will perform pressure fall-off tests. Pressure fall-off testing will be conducted on the injection wells to characterize reservoir properties as well as changes in the near-well/reservoir conditions that may affect operational CO_2 injection behavior.

10.1 TESTING LOCATION AND FREQUENCY

A pressure fall-off test will be conducted prior to operations and within ±45 days of the 2-½ year anniversary of the start of carbon dioxide injection and within ±45 days of the 5 year anniversary of the startup of injection. Thereafter, a pressure fall-off test will be performed at least once every 5 years during the operational period.

The designed duration of the pressure fall-off recovery test is a function of several factors, including the exhibited preoperational injection reservoir test response characteristics, injection well history prior to termination (i.e., injection duration, rate history), and potential pressure interference effects imposed by any surrounding injection wells completed within the same reservoir.

The shut-in period duration used in conducting the pressure fall-off test will extend sufficiently beyond wellbore storage effects and when the pressure recovery is indicative of radial flow as determined by the formation of a horizontal line on a log–log pressure derivative/recovery time plot. For the neighboring injection wells not being tested, injection rates will be held constant and continuously recorded prior to and during the fall-off test. The gauges used may be those used for day-to-day data acquisition, or pressure and temperature gauges conveyed via e-line.

Data will be collected at five second intervals or less through the entirety of the test. A SRT and/or a constant-rate pumping test will also be conducted prior to injection to measure the hydraulic properties of the formation, such as hydraulic conductivity and storability.

A record of test dates and data of each fall-off and step rate test will be kept by the site operator and maintained until project completion and be available to USEPA or LDNR upon request.

10.2 TESTING DETAILS

Testing procedures will follow the methodology detailed in EPA Region 6 UIC Pressure Fall-off Testing Guideline-Third Revision (August 8, 2002).

The downhole pressure gauge can be either installed as part of the completion or can be deployed via a wireline truck. GCS will utilize a wireline truck deployed gauge, the wireline will be corrosion resistant (such as MP-35 line), and the deployed gauges will consist of a surface read-out gauge with a memory backup. Gauge specifications will be similar to those shown in Table G.10.2-1.

General testing procedure is as follows:

- Mobilize wireline unit to the injection well and rig up on wellhead.
- Rig up a wireline lubricator containing a calibrated downhole surface-readout pressure gauge (“SRO”) with memory gauge installed in the tool string as a

backup, to the adapter above the crown valve. Each gauge should have an operating range of 0-10,000 psi. Reference the gauge to kelly bushing ("KB") reference elevation and the elevation above ground level.

- Open crown valve, record surface injection pressure, and run-in borehole with SRO to just above the shallowest perforations in the completion while maintaining injection at a constant rate. Steady rates of injection will be maintained for at least 24 hours ahead of the planned shut-in of the injection well. Any offset injection well will be either shut-in or maintaining a constant rate of injection for the entire duration of the testing. This will minimize any cross-well interference effects.
- With the SRO positioned just above the perforations, monitor the bottom-hole injection pressure response for ±1 hour to allow the gauge to stabilize (temperature and pressure stabilization). Ensure that the injection rate and pressure are stable.
- Cease injection as rapidly as possible (controlled quick shut-in); close the control valve and the manual flowline valve at well site (start with the valve closest to the wellhead so that wellbore storage effect in early time is minimized). Conduct the pressure fall-off test for approximately 24 hours, or until bottomhole pressures have stabilized.
- Lock out all valves on the injection annulus pressure system so that annulus pressure cannot be changed during the fall-off period. Ensure that valves on flow line to the injection well are closed and locked to prevent flow to the well during the fall-off period.
- After 24 hours, download data and make preliminary field analysis of the fall-off test data with computer-aided transient test software to estimate if or when radial flow conditions might be reached. If sufficient data acquisition is confirmed, end fall-off test. If additional data is required, extend fall-off test until radial flow conditions are confirmed. After confirmation of sufficient data acquisition, end fall-off test.
- Pull SRO tool up out of the well at 1,000 ft increments and allow the gauge to stabilize (five minutes each stop). Record stabilized temperature and

pressure. Repeat the process to collect stabilized pressure data (five-minute stops) at 1,000 ft intervals and in the lubricator.

11.0 CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

GCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the magnitude of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g) (LAC 43:XVII §3625.A.7). GCS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume (plume) and associated pressure (pressure front) relative to the permitted storage reservoir. The timeframe of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the pre-operational (baseline), operational, and post-operational periods.

[redacted] GCS will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan. During each review, monitoring data and operational data will be analyzed, the AoR will be reevaluated, and, if warranted, the testing and monitoring plan will be adjusted accordingly within one year. The testing and monitoring plan will be reviewed in this manner at least once every five years or following any significant changes to the facility to decide whether an amendment is necessary. The review and possible amendment are intended to ensure proper monitoring of the storage performance is achieved and that the risk profile of the storage operations is addressed. Should amendments to the Testing and Monitoring Plan be necessary, they will be incorporated into the permit following approval by USEPA or LDNR. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of CO_2 and pressure distribution relative to the pre-operational simulation result. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will in turn be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

11.1 DIRECT MONITORING

11.1.1 In-zone monitoring (IZ) details

[redacted]

[redacted] A packer will be set above the perforations and completed with downhole pressure gauges on tubing. Well design will enable geochemical sampling of the Injection Zone and wireline logging. Pressure readings will be taken daily and will be critical in understanding the pressure front evolution over time. [redacted]

11.1.2 CO_2 Plume Tracking

[redacted]

[redacted]

Fluid chemistry of the Confining Zone will be geochemically modelled by equilibrating water chemistry of the reservoir fluid with the seal rock, a common procedure to estimate pore-water chemistry of argillaceous rocks (Gaus et al, 2005).

Additional in-zone monitoring wells will be added, if necessary, to effectively track the CO_2 plume and demonstrate non-endangerment. New technological advances in direct pressure monitoring methods will be assessed throughout the life of the project to determine if implementation improves non-endangerment demonstration.

11.1.3 Pressure Front Tracking

[redacted]

[redacted]

11.2 INDIRECT MONITORING

11.2.1 CO_2 Plume Tracking

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

11.2.1.1 Vertical Seismic Profile (VSP)

A safety concern and monitoring challenge is verifying that injected CO_2 does not leak from the Injection Zone into the USDW and atmosphere. Seismic monitoring methods offer the most effective, cost-efficient solution.

An additional goal is to passively monitor for any seismic events induced by injection activities. These seismic events may indicate CO_2 leakage pathways.

GCS will implement time-lapse Vertical Seismic Profile ("VSP") to ensure well and storage integrity during CO_2 injection and to provide monitoring of the CO_2 plume migration throughout the lifetime of the project.

A VSP is a measurement in which a seismic signal generated at the surface of the earth is recorded by geophones secured at various depths within a well borehole or Distributed Acoustic Sensing ("DAS") fiber optic cable (Figure G.11.2-1), Stewart, 2001).

GCS will run a study in order to determine which is the most appropriate type of VSP for monitoring the CO_2 plume within the AoR, however, a WVSP will be the starting point due to its advantages and its compatibility with seismic inversions.

Furthermore, GCS will run a Quantitative Interpretation ("QI") project based on different types of seismic inversions with the objective of quantifying the changes in CO_2 saturation within the reservoir. The starting point will be the generation of Intercept and Gradient, which are the most basic AVO/AVA seismic attributes and are the inputs to some band limited seismic inversion techniques as well as for more complex deterministic inversion products.

Distributed Acoustic Sensing ("DAS")

DAS is a Fiber Optic ("FO") cable-based technology, which is gaining importance for VSP surveys, especially for time-lapse monitoring of reservoirs. DAS offers advantages over geophones, but it also poses unique challenges such as a receiver depth uncertainty and a low signal-to-noise ratio.

DAS technology eliminates the need for discrete point sensors by using the fiber itself as the sensor (Mestayer et al., 2011; Miller et al., 2012). This allows a single fiber to be employed as a continuous array of receivers (Bostick, 2000; Hornby and Burch, 2008).

The same fiber optic cables can be used for passive monitoring and detection of microseismic events. This addresses seismic hazard risk and leakage pathways, including the integrity of the wellbore. The use of DAS delivers data with greater detail in each shot record compared to the conventional geophones.

The following benefits of acquiring DAS VSP surveys have been identified:

- Safety: accurate, long-term or on-demand, resilient monitoring throughout the entire Injection Zone, for the entire mandated period
- Repeatability: permanent installations ensure high repeatability and continuous data availability without intervention at the wellbore
- Low maintenance: Fiber optic cables have no mechanical parts and are suitable for corrosive and high temperature environments. After installation they require no maintenance for decades, in line with mandates for CCS monitoring periods
- Cost savings: there is an associated significant cost saving normally in the order of millions of dollars
- Sustainability: the system's extreme sensitivity enables seismic imaging with minimal source effort on land, resulting in a reduced environmental impact and overall cost

GCS sees time-lapse VSP with DAS as an attractive proposition for frequent CO_2 monitoring around the injection wells, however, the final design will be subject to the results of the feasibility study.

11.2.1.2 VSP Workflow

As described above, the usage of time-lapse seismic for the purpose of reservoir monitoring has a long history in tertiary oil and gas recovery. The methodology has also been extensively tested in saline aquifers with CO_2.

The primary work steps involved in a time-lapse VSP survey are the following:

- Rock physics model
- Petro-elastic model
- Fluid substitution
- Synthetic seismograms (1D and 2D models)
- Feasibility study
- Baseline survey design
- Baseline survey acquisition

- Baseline survey processing
- Repeat/time-lapse survey (monitor acquisition)
- Monitor survey processing and possible baseline survey re-processing
- Interpretation/data analysis
    - Calibration
    - Subtraction

Rock Physics Model

Rock physics modeling aims to provide a link between rock properties such as porosity, lithology, and fluid saturation, and elastic attributes, such as velocities or acoustic impedance.

A comprehensive, well-calibrated rock physics model allows the following:

- Prediction of elastic properties (P-velocity, S-velocity, and density) based on input volumes form petrophysical interpretation
- Integration of petrophysical (reservoir) properties and geophysical (elastic) properties
- Generation of consistent facies and fluid volumes
- Prediction and replacement of poor-quality log data, missing (unrecorded) log data, and correction for invasion effects

The rock physics model is a critical element for the interpretation of the time-lapse effects because it provides the correlation between fluid substitution and changes in the acoustic impedance. A high level of confidence may be held in this model assuming the reservoir characterization program is adequately thorough.

Usage of deterministic petrophysical analysis predictions can be made for estimating the dry mineral components of the rock before any saturation is modelled. These components are:

- Total porosity
- Effective porosity
- Water saturation

- Clay (type)
- Quartz
- Mineral content

GCS will use RokDoc software from Ikon Science that offers a [redacted]

Petro-Elastic Model ("PEM")

A PEM is a set of rules that can be used to compute the elastic properties from the studied reservoir properties. Reflection coefficients can be calculated from these elastic properties and then convolved with a wavelet to obtain a synthetic seismic response. Thus, the PEM provides a link between the reservoir and the elastic domain.

A PEM is essential to any quantitative workflow designed to predict reservoir properties from seismic data. With the advent of time-lapse monitoring, petro-elastic modeling has become a key element in 4D history matching and reservoir characterization.

The petro-elastic model takes the zero-order dry rock model generated from the rock physics model and perturbs the elastic parameters for different degrees of saturation.

Using the rock physics model, fluid saturations and fluid substitutions can be used to predict elastic properties.

The result of the PEM is the ability to predict the velocity and density as a function of the saturation. These two elastic properties determine the AI which can be used to determine the seismic response measured during VSP surveys.

Fluid Substitution

The objective of a fluid substitution is to model the seismic properties (seismic velocities) and density of a reservoir at a given reservoir condition (e.g., pressure, temperature, porosity, mineral type, and water salinity) and pore fluid saturation such as 100% water saturation or hydrocarbon with only oil or only gas saturation. This workflow allows the interpreter to observe the effects of different pore-fluid saturation on the velocities and the acoustic impedances ("AI"), which can then be used to interpret the time-lapse results from the VSP data acquired.

Fluid substitution analysis is used to model changes in seismic properties from different fluid scenarios. Key inputs to the fluid substitution modeling are P and S-wave velocities, and the bulk density information from key well(s). A prerequisite to this model is a well-to-seismic tie.

Synthetic Seismogram (1D and 2D Modeling)

To predict the change in seismic amplitude due to CO_2 injection, 1D and 2D models will be generated based on the result of the fluid substitution modeling. The original logs that contain no CO_2 will be compared with those containing CO_2 saturations defined for modeling purposes. Then the changes in the P-wave velocity will be observed, expecting a decrease in velocity on the CO_2 saturated one. This is a standard step done in rock physics studies to understand what the seismic amplitudes are responding to.

The presence of CO_2 should cause a decrease in velocity resulting in a negative amplitude/reflection coefficient or a trough. This conforms with the Society of Exploration Geophysicist ("SEG") convention, where an increase in acoustic impedance is represented by a peak (positive amplitude), and a decrease in acoustic impedance is represented by a trough (negative amplitude).

The outputs of the modeling will be a 1D model (synthetic seismogram) for each case scenario, meaning in situ (dry rock) versus a specific CO_2 saturation (Figure G.11.2-2), and 2D models to reflect the two saturation cases. Two VSP geometries have been selected for illustration purposes (Figure G.11.2-3 and Figure G.11.2-4). The magnitude of the difference determines whether it will be possible to use VSP technology to monitor the CO_2 front. 2D modeling is critical in determining the offset distance that can be achieved by monitoring.

An example of two shots saturation models is displayed on Figure G.11.2-3 used to model a VSP response where a change in amplitude is observed suggesting the effectiveness of VSP in monitoring fluid changes within the rock.

Feasibility Study

GCS will perform a series of background studies prior to the beginning of the injection to ensure the security of the geological sequestration of the CO_2. Within Project Minerva, numerous wells and 3D seismic surveys provide information about the lithology, porosity, permeability, velocities and other parameters of the medium needed to characterize the subsurface. Using this data as inputs, GCS will perform a series of numerical simulations that will determine the optimum time-lapse monitoring method.

Reservoir model predictions of fluid saturations can be used to reconstruct the elastic properties. Forward modeling determines the changes that these substitutions induce on the seismic response. This change in synthetic seismic response determines whether the substitutions made by the reservoir model are pronounced enough to induce a time-lapse effect or not.

An effective feasibility study allows the prediction of how and when potential failure scenarios are evident on the seismic domain. Three standard case scenarios will be generated:

1. Base Case – injected volumes are placed within the storage reservoir
2. Caprock Breach – A breach in the caprock is simulated which allows for migration of fluids to occur out of the intended storage reservoir
3. Open Fault – An offset open fault channels fluid preferentially out of the intended storage reservoir

From an initial rock property model (base and monitor), ray tracing models will be used to determine optimum survey geometry, followed by finite difference models and migration of the model data (both cases). Difference between them, as shown on Figure G.11.2-5, will be generated to understand the changes along different time selection to select best time for monitoring.

The frequency with which to acquire time-lapses will be a balance between waiting long enough for sufficient formation changes to occur and minimizing the likelihood that injection is occurring outside of the intended zone. This frequency may not be uniformly spaced throughout the injection timeframe as the plume in early phases of injection evolves more rapidly than in later timeframes.

<u>Baseline Survey Design and Acquisition</u>

[redacted]

[redacted]

Baseline Survey Processing

GCS has designed a preliminary seismic processing sequence that will be applied based on standard steps for traditional geophones and a 3D VSP survey; however, GCS is exploring the possibility of using DAS for the monitoring.

Data Analysis and Interpretation

To monitor the injected CO_2, differences in time lapse data must be identified. This is accomplished by subtracting pre-injection sections from post-injection shot gathers.

Pre-injection data will be used for each of these filters as a reference volume to analyze, compare, and apply the required changes to post-injection data.

This anisotropy might be attached to the state of stress in the formations or fracture intensity and direction. GCS will use the frequency loss in the first few cycles of the down-going energy over several levels to calculate an attenuation. This absorption (Q factor) can be used as a rock property or in Q-compensation on surface seismic data.

12.0 ENVIRONMENTAL MONITORING AT THE SURFACE

The primary objective of the proposed surface sampling and investigation workplan is to evaluate baseline conditions of surface water and ecological conditions within the AoR. Initial characterization and sampling program will be carried out prior to CO_2 injection. Baseline conditions will be established where possible over multiple seasons to quantify the natural background variability of these systems and to establish action levels (threshold concentrations). In contrast with deep subsurface monitoring, the chemical compositions of surface water/sediment sampling and near-surface atmosphere are subjected to strong seasonal effects and are influenced by a range of natural processes and human activities.

The duration of the baseline, operational and post-operational surface monitoring and the frequency of data sampling are shown in Table G.13.1-1 for ground surface and atmospheric monitoring.

12.1 ATMOSPHERIC MONITORING

GCS proposes to carry out fixed-point CO_2 monitoring to measure CO_2 at fixed locations, with routine sampling for CO_2 and tracer gas concentrations. Tracer gases will provide improved leak-detection capability.

The monitoring method will consist of CO_2 point monitoring and analysis performed four times during the one-year baseline monitoring, quarterly during the first three years of injection period, and quarterly every 5 years to injection is complete. The post-injection atmospheric monitoring will be performed quarterly every five years up to 50 years of post-injection.

It is important to note that the inclusion of atmospheric monitoring there is undoubtedly the potential for false positives due to climate change affecting CO_2 concentration in the atmosphere using this approach. There may be a high degree of false positives as increased concentration of CO_2 in the atmosphere will likely result from a changing climate or human activities surrounding the AoR. All results from atmospheric monitoring will be correlated to other monitoring methods to minimize potential false positives.

12.2 ECOLOGICAL MONITORING

GCS proposes to carry out four baseline ecological surveys as the pre-operational monitoring and characterization to establish baseline conditions for comparisons with operational monitoring results. Included in the ecological monitoring is surface-water monitoring (measurement of pH, temperature, electrical conductivity, and dissolved oxygen content of nearby surface waters). In conjunction with surface water monitoring, a visual vegetation condition assessment to characterize vegetation conditions and detect subtle changes in normal plant growth processes and relative vegetation stress will be performed. For broader coverage across the area of the project, ecosystem stress monitoring is required and can be attained with remote methods such as satellite imagery, aerial photography, and spectral imagery.

The monitoring methods consist of the ecological survey for baseline, followed by surface water monitoring, and vegetation conditions, as indicated. The ecological survey will be performed 4 times, in different seasons, during the one-year period of baseline monitoring, before injection commences. During the operation, the ecological survey will be performed annually during the first three years of injection period, and the next ones will be performed at 5-year intervals until injection is complete. The post-injection ecological monitoring will be performed every five years up to 50 years of post-injection. There may be a high degree of false positives as vegetation changes due to stress from drought, possible infestations or diseases that may result from a changing climate. Therefore, ecological monitoring results will always be correlated to other monitoring methods.

A 1-mile by 1-mile grid was placed on the AoR and sampling points were selected to ensure all waterbodies and individual ecological systems were accounted for, Figure G.12.2-1. A total of 22 sites were selected on the grid for surface water monitoring. G.12.2-1 provides potential tests for water and sediment sampling.

12.2.1 Surface Sampling Standard Operating Procedures (SOP)

12.2.1.1 Surface Water

SOP describes procedures and equipment commonly used for collecting environmental samples of surface water and aquatic sediment for either onsite examination and chemical testing or for offsite laboratory analysis. Collecting a representative sample of surface water or sediment may be difficult because of water movement, stratification, or heterogeneous distribution of the targeted analytes. To collect representative samples, one must standardize sampling methods related to site selection, sampling frequency, sample collection, sampling devices, and sample handling, preservation, and identification. Regardless of quality control applied during laboratory analyses and subsequent scrutiny of analytical data packages, reported data is no better than the confidence that can be placed in the representativeness of the samples.

The selection of sampling equipment depends on the site conditions and sample type to be acquired. In general, the most representative samples are obtained from mid-channel at a stream depth of 0.5 ft in a well-mixed stream. In these conditions direct sampling with sample containers is most efficient. Barring other considerations like physical access limitations or cross-contamination by contact of the outside of the container with the water body, direct collection by submerging the sample container is the preferred method for collecting a surface water sample, when possible. Samples from shallow depths will be collected by submerging the sample container. This method is advantageous when the sample might be significantly altered during transfer from a collection vessel into another container. This method should not be used for sampling lagoons or surface impoundments where contact with contaminants is a potential concern or if sampling for volatile organic compounds (VOC) or other analytical parameters requiring pre-preserved sample containers.

The following procedure describes the effective sampling of surface water. Figure G.12.2-2 provides an example of a water sampling log, for reference:

1. Place all equipment on plastic sheeting next to the sampling location. Sample containers will be selected in accordance with the requirements specified in

the project-specific field work plan, field sampling plan, or quality assurance project plan (QAPP).

2. If required by the project, measure field parameters (such as temperature, conductivity and pH) using procedures in relevant specific SOPs and project-specific field sampling plans. Record this information on the field data sheet or in the logbook.

3. A visual check for visible surface material (pond scum or ice) will be performed before sampling. If present, surface water samples will be collected by directly submerging the sample container (with lid still on) into the surface water at the specified sampling location. Avoid contacting the bottom of the water body with the sample container because this will disturb sediment that may interfere with the surface water sample. Once submerged, the lid will be removed to allow the container to fill with water below any visible material on the surface of the water. A visual check will be conducted during and after sample collection to ensure sample integrity. If no surface materials are present, sample as instructed below.

4. For stream sampling, sample the location farthest downstream first. In general, work from zones suspected of low contamination to zones of high contamination. Orient the mouth of the sample container facing upstream while standing downstream so as not to stir up any sediment that would contaminate the sample. Avoid contacting the bottom of the water body with the sample container because this will disturb sediment that may interfere with the surface water sample.

5. For a larger body of surface water, such as a lake, collect samples near the shore, unless boats are feasible and permitted. Collect samples from shallow depths by submerging the sample container. Avoid contacting the bottom of the water body with the sample container because this will disturb sediment that may interfere with the surface water sample. If sampling from a boat, collect the sample as far away as possible from the outboard engine to avoid possible fuel contamination.

6. If sediment samples are to be collected with surface water samples, collect surface water samples at each location before collecting sediment samples to

avoid contaminating the water samples with excess suspended particles generated during sediment sampling.

7. Allow the water to fill the container until it is almost full.

8. Add preservative to the sample in accordance with requirements specified in the project-specific field work plan, field sampling plan, or QAPP. Secure the cap tightly and affix a completed sample label to the container.

9. Complete all chain-of-custody documentation, field logbook entries, and sample packaging requirements.

12.2.1.2 Sediment

[redacted] If only one sediment sample is to be collected, the sampling location shall be approximately at the center of the water body.

Generally, coarser-grained sediments are deposited near the headwaters of reservoirs. Bed sediments near the center of a water body will be composed of fine-grained materials that may, because of their lower porosity and greater surface area available for adsorption, contain greater concentrations of contaminants. The shape, flow pattern, bathymetry (i.e., depth distribution), and water circulation patterns must all be considered when selecting sediment sampling sites.

Samples collected for VOC analysis must be collected prior to any sample homogenization. Regardless of the method used for collection, the aliquot for VOC analysis must be collected directly from the sampling device (hand auger bucket, scoop, trowel), to the extent practical. If a device such as a dredge is used, the aliquot will be collected after the sample is placed in the mixing container prior to mixing.

A bottom-material sample may consist of a single scoop. A scoop sampler consists of a pole to which a jar or scoop is attached. The pole may be made of bamboo, wood, PVC, or aluminum and be either telescoping or of fixed length. The scoop or jar at the end of the pole is usually attached using a clamp.

If the water body can be sampled from the shore or if the sampler can safely wade to the required location, the easiest and best way to collect a sediment sample is to use a scoop sampler. Scoop sampling also reduces the potential for cross-contamination. Figure G.12.2-3 provides an example of a soil sampling log, for reference.

A typical scoop sampling procedure is as follows:

1. Place all equipment on plastic sheeting next to the sampling location. Sample containers will be selected in accordance with the requirements specified in the project-specific field work plan, field sampling plan, or QAPP.
2. Reach over or wade into the water body
3. While facing upstream (into the current), scoop the sampler along the bottom in an upstream direction. Although it is very difficult not to disturb fine-grained materials at the sediment-water interface when using this method, try to keep disturbances to a minimum.
4. Complete all chain-of-custody documentation, field logbook entries, and sample packaging requirements.

13.0 SAMPLING/DATA PROCEDURES

13.1 DATA REVIEW AND VALIDATION

Data will be reviewed by the project operator or designee on an ongoing basis as the data are collected in the field and as results are received from the laboratory. Data review will consist of (for example):

1. Verifying that data collection and calibrations/QC checks are complete and fully documented
2. Examining raw data values and trends for consistency and reasonableness
3. Making comparisons between related measured parameters and calculated values for agreement within reasonable expectations
4. Flagging incomplete, invalid or suspect data and documenting the reason for the flag
5. Initiating investigative or corrective actions as needed.

All valid data will be included in the data analysis and reflected in the reported results. Suspect data may or may not be considered or may receive special treatment as will be specifically indicated. The impact on data quality of any problems or issues that arise will be fully assessed, documented and reported. Any limitations on the use of the resulting data will be fully assessed and reported.

13.2 SAMPLE HANDLING AND CUSTODY

13.2.1 Chain-of-Custody ("COC")

Proper sample handling and custody procedures ensure the custody and integrity of samples beginning at the time of sampling and continuing through transport, sample receipt, preparation, and analysis. The COC is used to document sample handling during transfer from the field to the laboratory. The sample number, location, date, changes in possession and other pertinent data will be recorded in indelible ink on the form. The sample collector will sign the COC and transport it with the sample to the laboratory. At the laboratory, samples are inventoried against the accompanying COC. Any discrepancies will be noted at that time and the COC will be signed for acceptance of custody.

13.2.2 Sample Handling and Labeling

Samples will be labeled on the container with an indelible, waterproof marker. Label information will include site identification, date, sampler's initials, and time of sampling. The COC form will accompany all sets of sample containers. Following collection, samples will be preserved and transported to the appropriate analytical laboratory for analysis.

13.3 AUDITS, QUALITY ASSESSMENT AND RESPONSE ACTION

The technical systems audit is intended to ensure that the sampling, data collection and analysis, QA/QC measures, and documentation are executed in accordance with this plan and that the quality impact of any deviations from the plan is fully assessed and documented. To this end, the internal reviewer will prepare an audit checklist including all key elements of this plan and, to the extent possible, systematically verify in the field that each key element is conducted according to plan.

The audit of data quality will consist of verifying that reported results are fully supported by the data collected by tracing each result back to its sources in the raw data and verifying that all required QA/QC is complete and documented for each data source, and that calculations are correct, and results and uncertainties are correctly reported.

13.4 DATA MANAGEMENT AND RECORDS

GCS will be responsible for ensuring that all electronic and hard copy data, forms and logs are accounted for, properly completed and stored in project files.

Documentation will be sufficient that a third party can reproduce the results from the raw data. This requires that all necessary information will be documented, and that the documents are organized and maintained such that the information may be practically retrieved and made use of.

Documentation will consist of instruments and other digital files, hard copy field log sheets, calibration certificates, laboratory reports, etc. All of these documents will ultimately be stored in electronic form; however, hard copy log sheets will be retained on file. An electronic data package will be compiled containing project documentation sufficient to allow a third party to reproduce the results and organized in such a manner that this may be done without undue effort.

13.5 MANAGEMENT OF CHANGE

Changes or deviations from this plan may be necessitated by field conditions, unexpected events, observations, or opportunities to improve the results as determined by the project operator. In such events, the reason for the change, and the new measures implemented will be documented in a note to the project log (if the change is minor) or deviations memorandum. This will include an assessment of the impact of the change on data quality. Verification of this will be part of the internal field and data audits.

Comprehensive deviations memorandum will be prepared including an overall assessment of all changes on data quality. Any new or revised procedures will be documented. Significant deviations and their impact on data quality will also be addressed in the final report.

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