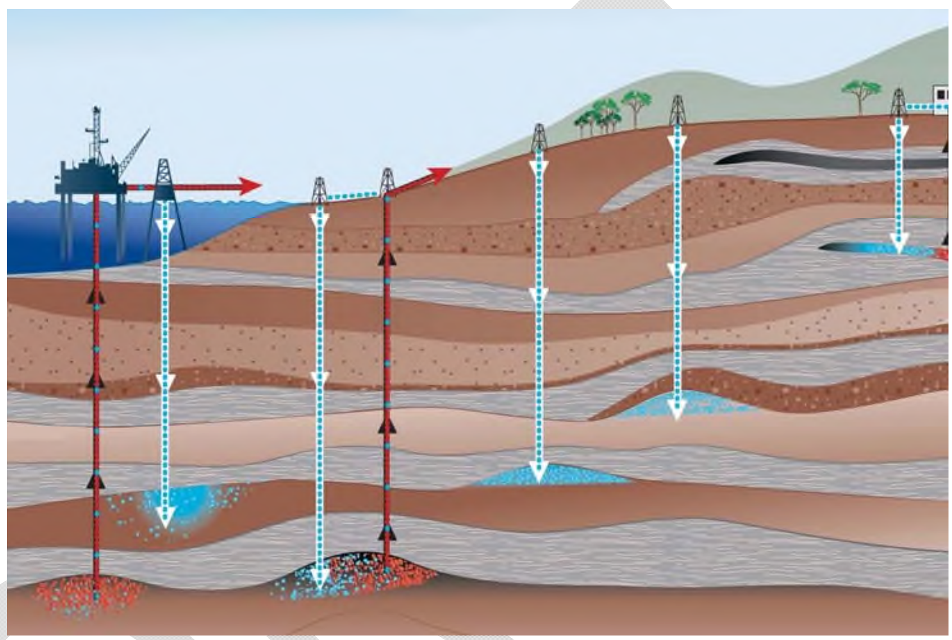

Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Fuel Standard

Disclaimer

This document is still under review by the Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR), and any feedback from DOGGR will be reflected in the next version of this document. In addition, this document is made publicly available such that stakeholders can have an early opportunity to review and respond, and the document may still have missing sections, typographical errors, and the section cross-references may be incorrect.

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A. DEFINITIONS AND APPLICABILITY

1. Purpose

The purpose of the California Air Recourses Board’s (CARB) Accounting and Permanence Requirements for Carbon Capture and Geologic Sequestration (CCS Protocol) is to establish a methodology by which to determine whether a Carbon Capture and Sequestration (CCS) project will result in permanent sequestration of carbon dioxide (CO_2) and, if so, how to calculate the greenhouse gas (GHG) benefits from such a project under the Low Carbon Fuel Standard (LCFS). The CCS Protocol is guided by requirements in AB 32 that GHG emissions reductions achieved from voluntary action, such as CCS projects, must be real, permanent, additional, quantifiable, verifiable, and enforceable.

The Accounting Requirements covers emissions associated with CCS projects, including emissions from CCS operations, CO_2 surface leakage, above ground fugitive emissions, and post-well closure emissions. Applicants must use the Accounting Requirements to calculate credits or carbon intensity reductions for CCS projects under LCFS.

The Permanence Requirements establishes provisions for the permanent geologic sequestration of CO_2 for CCS projects to qualify for GHG reductions (or non-emissions) under CARB’s existing climate programs in compliance with Assembly Bill 32.[1] The Permanence Requirements sets forth criteria and standards that geologic carbon sequestration (GCS) projects must implement in order to acquire Permanence Certification.

2. Definitions and Acronyms

(a) Definitions: For purposes of this document, the definitions in title 13, California Code of Regulations, section 95481 apply, except as otherwise specified in the document. The following definitions also apply to this document:

“Active life” means the operational phase of a GCS project in which injection and, if applicable, production occurs. The term omits the monitoring and site care phase of the GCS project following injection completion.

“Area of review (AOR)” encompasses the region, in three dimensions, overlying and surrounding all CO_2 injection wells, in which the extent of fluid-pressure rise due to injection is sufficient to drive CO_2 or formation fluids upward and outward from the sequestration zone into the subsurface, assuming either hypothetical or real flow pathways, such as wells or fractures, are present. The area of review also encompasses the region, in three dimensions, overlying the free-phase (e.g., supercritical, liquid, or gaseous) CO_2 plume. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all

[1] Assembly Bill 32, the Global Warming Solutions Act of 2006, AB 32, Statutes of 2006, Chapter 488.

phases of the injected CO_2 stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in **Sections 2**, **3**, and **4**.

"Area of review for dissolved CO_2" encompasses the region, in three dimensions, overlying and surrounding the sequestration zone and all CO_2 injection wells, extending out to the limit of the predicted leading edge of the dissolved CO_2 plume.

"Aqueous diffusion coefficient" is the magnitude of the molar flux through a surface per unit concentration gradient. Typical diffusion coefficients for organic compounds in aqueous solution range between 10^{-10} to 10^{-9} m^2/s.

"Artificial penetration" means any man-made structures, such as wells or mines, which provide a flow path out of the sequestration zone.

"Assets" means all existing and all probably future economic benefits obtained or controlled by a particular entity.

"Biogenic CO_2" refers to CO_2 produced from biomass.

"Borehole" means a cylindrical hole cut into rock or soil by drilling. Also refers to the inside diameter of the wellbore wall (i.e., the rock face that bounds the drilled hole).

"Bottomhole pressure" means the pressure at the bottom of the wellbore within the sequestration zone. It may be measured directly with a downhole pressure transducer, or in some cases estimated from the surface pressure and the height and density of the fluid column.

"Brine" is water containing dissolved minerals and inorganic salts in solution, including sodium, calcium or bromides. Water containing dissolved solids in excess of 100 g/L is classified as brine. Large quantities of brine are often produced along with oil and gas.

"Brittleness" is a property of a rock in which failure under a load occurs by fracturing, rather than by plastic deformation.

"Capillary pressure" means the pressure difference across the interface of two immiscible fluids (e.g., CO_2 and water).

"Capillary entry-pressure" means the pressure that a non-wetting fluid (e.g. CO_2) must overcome to displace water held tightly by capillary forces in the pores of a confining layer.

"Capture Facility Operator" means the operator responsible for the CCS capture facility.

“Carbon capture and sequestration (CCS)” means the process of concentrating CO_2 present in flue and/or exhaust gases, or air, via chemical and/or physical separation methods, transporting the CO_2 to an injection site, and injecting and permanently sequestering the captured CO_2.

“Carbon dioxide equivalent” or “CO_2 equivalent” or “CO_2e” means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas. For the purposes of the LCFS CCS Protocol, global warming potential values listed in the CA-GREET model are used to determine the CO_2 equivalent of GHG emissions.

“Carbon intensity” has the same meaning as in 13, CCR, section 95481.

“Casing” or “casing string” means a pipe or tubing of appropriate material (typically made of steel as used in oil and gas wells), of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent the loss of drilling mud into porous ground, to prevent water, gas, or other fluid from entering or leaving the hole, or to allow conveyance of fluids to/from the surface from/to a specific location in the subsurface. “Long string casing” refers to the last, or longest, casing set in a well, set through the sequestration or production reservoir. “Surface casing” refers to the first string of casing that is set in a well, and varies in length from a few hundred to a few thousand feet.

“Casing inspection logs (CIL)” are used to determine the presence or absence of corrosion in the long-string casing. CILs measure casing thickness or borehole radius. One of several available logs may be used for a CIL, including physical measurement with a caliper, electromagnetic phase shift in the magnetic field passing through the tubing or casing, electromagnetic flux leakage due to variations in the tubing or casing, and ultrasonic images of reflected sound waves. Each of the methods provides data that, along with the physical characteristics of the well, will yield the thickness of the casing and the locations of anomalies, such as corrosion pits, scratches, and splits.

“Casing shoe” means the bottom of the casing string or the equipment run at the bottom of the casing string.

“CCS capture facility” means any plant, building, structure, or stationary equipment that captures CO_2 generated from industrial processes, or the atmosphere.

“CCS project” means the overall CCS project operations, including those of the CCS capture facility and the GCS project.

“CO_2-enhanced oil recovery (CO_2-EOR)” means the injection into and storage of CO_2 in oil reservoirs contributing to the extraction of crude oil.

“CO_2 injection” means is the process of injecting CO_2 in a supercritical state into geologic reservoirs.

“CO_2 leakage” means any movement of stored CO_2 out of the intended sequestration zone and above the secondary confining layer. “Atmospheric leakage” means the intended or unintended release of stored CO_2 outside the sequestration zone to the atmosphere or a wellbore. “Subsurface leakage” means the vertical and/or lateral movement of stored CO_2 out of the intended sequestration zone and/or AOR that does not reach the atmosphere.

“CO_2 plume” means the physical extent underground, in three dimensions, of an injected CO_2 stream.

“CO_2 stream” means CO_2 that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process.

“CO_2 recycling” means the process that separates CO_2 from produced oil, water, and gas for re-injection in the subsurface or transfer off-site.

“Computational model” means a mathematical representation of the injection project and relevant features, including injection wells, site geology, and fluids present. For a GCS project, site-specific geological information is used as an input to a computational code, creating a computational model that provides predictions of subsurface conditions, fluid flow, and CO_2 plume and pressure front movement at that site. The computational model includes all model input and predictions (i.e., outputs).

“Confining pressure” means the combined hydrostatic and lithostatic stresses, or the total weight of the interstitial pore water and rock above a specified depth.

“Confining layer” means a laterally extensive geologic formation, group of formations, or part of a formation, stratigraphically overlying the sequestration zone that exhibits low permeability and/or high capillary entry-pressure (e.g. a clay-rich shale or mudstone) such that it impedes the upward migration of fluid(s). The “primary confining layer” refers to the confining layer directly above the sequestration zone. “Secondary confining layer” refers to the confining layer directly above the dissipation zone above the storage complex.

“Constitutive relationships” represent empirically based approximations used to simplify the real-world system and estimate unknowns. Examples include saturation-relative permeability relationships, interphase mass transfer relations, and solution reaction relations.

"Corporate parent" means a corporation that directly owns at least 50 percent of the voting stock of the corporation that is the GCS Project Operator; the latter corporation is deemed a subsidiary of the parent corporation.

"Corrective action" means the use of California Air Resources Board-approved methods to ensure that any artificial penetrations within an AOR do not serve as conduits for the movement of fluids out of the intended sequestration zone.

"Corrosion" means the loss of metal due to chemical or electrochemical reactions that may cause loss of mass or thickness, cracking, or pitting of injection well components (casing, tubing, or packer). Corrosion can cause the loss of the mechanical integrity of a well via localized thinning or crack propagation in the well components. This, in turn, can cause the well to leak CO_2.

"Corrosion coupons" are small, pre-weighed, and measured pieces of metal made of the construction materials that are exposed to well fluids for a defined period of time, then removed, cleaned, and weighed to determine the corrosion rate. The coupon is made from the same material as the well's casing or tubing. The average corrosion rate in the well is calculated from the weight loss of the coupon.

"Corrosion loops" are sections of tubing that are valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. These loops allow for monitoring and analysis of corrosion.

"Current assets" means cash or other assets or resources commonly identified as those which are reasonably expected to be realized in cash or sold or consumed during the normal operating cycle of the business.

"Current liabilities" means the obligations whose liquidation is reasonably expected to require the use of existing resources properly classifiable as current assets or the creation of other current liabilities.

"Darcy's law" is an equation that defines the ability of a fluid to flow through a porous medium such as rock. It relies on the fact that the amount of flow between two points is directly related to the difference in pressure between the points, the distance between the points, and the interconnectivity of flow pathways in the rock between the points.

"Depleted oil and gas reservoirs" means the reservoirs which do not currently produce oil or gas, are considered to have no recoverable oil or gas with current technology, and furthermore will not produce oil or gas upon CO_2 injection.

"Depositional environment" is a specific type of place on the surface of the earth in which certain chemical, biological, and physical characteristics affect the deposition of sediments. The three overarching types of depositional environment include continental, marginal marine, and deep marine.

"Deviated well" means a well that is not drilled vertically for its whole length, or a well with an inclination other than zero degrees from vertical.

"Dissipation interval" is a stratigraphic interval with hydrogeologic properties sufficient to fully dissipate any potential overpressure created by CO_2 or formation fluid migration along an unidentified leakage pathway through the confining layer.

"Downhole measurements" are measurements collected from within the wellbore or borehole, either while drilling or during well maintenance or operation. Downhole measurements are used to determine physical, chemical, and structural properties of formations penetrated by a drill hole. Using a variety of instruments, these measurements are collected to make continuous *in-situ* records as a function of depth.

"Ductility" means the property of a rock by which the rock plastically deforms under a load, rather than breaking by fracturing.

"Embodied GHG" means lifecycle greenhouse gas emissions associated with production and transport of process fuels and chemicals to the point of use (e.g., GHG from the production and transport of natural gas process fuel to a refinery).

"Entrained CO_2" means CO_2 that remains in water, oil, or natural gas after CO_2 recycling.

"Equation of state" refers to an equation that expresses the equilibrium phase relationship between pressure, volume, and temperature for a particular chemical species.

"Fluid" means liquid or gas.

"Fluid pressure" means the measure of the potential energy per volume of fluid, based on force acting per unit area (psi or kPa).

"Formation compressibility" is the relative volume change of a formation per unit pressure change.

"Fracture pressure" is the pressure in the wellbore above which the injection of fluids will cause the rock formation to fracture hydraulically.

"Fracture gradient" is the factor used to determine formation fracturing pressure as a function of well depth in units of psi/ft.

"Free-phase CO_2 plume" means the portion of the sequestration zone pore space that is occupied by CO_2 in supercritical, gaseous, or liquid phase rather than as a dissolved component in native fluid (e.g., dissolved in brine).

"Freshwater aquifer" means an aquifer that contains fewer than 10,000 mg/L total dissolved solids per the U.S. EPA Safe Drinking Water Act[2].

"Fugitive emissions" means unintentional leakage of greenhouse gases from such as connectors, block valves, control valves, pressure relief valves, orifice meters, and regulators.

"Geographic location" means the location of a well or monitoring site as referenced to a geographic coordinate system (e.g. latitude and longitude) using a global positioning system.

"Geologic carbon sequestration (GCS)" means the permanent (>100 years) containment of CO_2 within deep subsurface rock formations. This term does not include the capture or transport of CO_2.

"GCS project" means an injection well or wells used to emplace a CO2 stream into a deep geologic formation, and any production and monitoring wells involved in that process. It includes the subsurface, three-dimensional extent of the CO_2 plume, associated area of elevated pressure, free-phase and dissolved plume, and displaced formation fluids, as well as the surface area above the delineated plume region and any above ground structures or stationary equipment within that area.

"GCS Project Operator" means the operator responsible for the GCS project.

"Geologic formation" means a body of rock characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.

"Geomechanical analysis" means to study rock mechanical characteristics and properties, such as fault and reservoir rock stability and confining layer integrity.

"GHG emissions reductions" means the amount of greenhouse gas emissions (MT CO_2) caused by limiting the carbon intensity of fuels under LCFS.

"Governing equation" means the mathematical formulae that form the basis of a computational code. For GCS modeling, they govern the predicted behavior of fluids in the subsurface provided by the code. Governing equations are mathematical approximations for describing flow and transport of fluids and their components in the environment.

"Hydraulic conductivity" is a measure of a material's capacity to transmit a fluid. It is defined as a constant of proportionality relating the specific discharge of a porous medium under a unit hydraulic gradient in Darcy's law.

[2] EPA Safe Drinking Water Act, 42 U.S.C. §300f *et seq.* (1974).

"Hydraulic head" is the force per unit area exerted by a column of liquid at a height above a depth and pressure of interest. In general, fluids flow down a hydraulic gradient, from points of higher hydraulic head to points of lower hydraulic head.

"Hydrostatic stress" means the component of the confining pressure derived from the weight of pore water in a column of rock above a specified depth.

"Induced seismicity" means earthquakes that are caused by human activity (e.g., wastewater injection).

"Injection and storage site" means the site where CO_2 injection and storage occurs.

"Injectivity" means the pressure differential over existing reservoir pressure required to inject a unit volume of fluid in a given unit of time. It is typically expressed as psi/bbl/day (psi per barrel per day), but can be expressed in any combination of pressure, volume, and time units.

"Injectivity test" means a well test in which CO_2 is pumped into the well and the pressure response in the well is recorded. Injectivity testing is used to determine the transmissivity of the formation, the skin factor, and to identify faults and fractures near the wellbore. Several variations on injectivity testing may be performed. A multi-rate injection test uses two or more injection rates to produce more data for a more complete analysis. Each injection rate is held long enough to obtain radial flow. In interference tests, fluid is injected into one well and the pressure is measured at another well. The interference test can yield information on the porosity and compressibility of the formation between the two wells.

"Intrinsic permeability" refers to a parameter that describes properties of the subsurface that impact the rate of fluid flow. Larger intrinsic permeability values correspond to greater fluid flow rates. Intrinsic permeability has units of area (distance squared).

"Isochore map" means a contour map showing equal values of true vertical thickness of a formation.

"Isopach map" means a contour map showing equal values of true stratigraphic thickness of a formation.

"Leak-off test" is a test to determine the strength or fracture pressure of the formation, usually conducted immediately after drilling below a new casing shoe. The results of the leak-off test dictate the maximum pressure or mud weight that may be applied to the well during drilling operations. To maintain a small safety factor to permit safe well control operations, the maximum operating pressure is usually slightly below the leak-off test result.

“Liner” means a casing string that does not extend to the top of the wellbore (i.e., the ground surface), but instead is anchored or suspended from inside the bottom of the previous casing string. The liner can be fitted with special components so that it can be connected to the surface at a later time if need be.

“Lithofacies” means a mappable subdivision of a rock unit with distinctive and characteristic lithologic features.

“Lithology” means the general description and classification of a rock or rock sequence in terms of their color, texture, and composition.

“Lithostatic stress” means component of confining pressure derived from the weight of the column of rock above a specified level.

“Mechanical integrity” means that all well barrier envelopes, including but not limited to, the tubing, packer, wellhead, and casing, reliably perform their primary functions of containing pressure and are free from leakage.

“Mechanical integrity test” means a test that consists of two parts conducted on a well to ensure that there are no leaks and that the mechanical components of the well function in a way that is protective of public health and the environment. The injection well has two parts: internal and external. The internal part has mechanical integrity if no leakage is noted in the packer, casing, or tubing. The external part has mechanical integrity if no movement of fluid is noted through the vertical channels that are adjacent to the well.

“Microannuli” means small gaps that may form between the casing or liner and the surrounding cement sheath within a well. Microannuli most commonly form due to temperature and/or pressure fluctuations during or after the cementing process. Such fluctuations cause small movement of the steel casing, breaking the cement bond and creating a microannulus. If it is severe and connected, a microannulus can jeopardize the hydraulic efficiency of a primary cementing operation, allowing communication between formations and the possibility of fluid migration out of the primary sequestration zone.

“Model domain” means the lateral extent of the model in all directions.

“Model parameter” means a variable in the governing equations of a computational model that may vary throughout the domain, or may vary in space and time. Various system aspects are sometimes lumped together in simulation models and described by effective parameters that are estimated or averaged. Parameters describe properties of the fluids present, porous media, and fluid sources and sinks (e.g., injection well). Examples of model parameters include intrinsic permeability, fluid viscosity, and fluid injection rate.

“Multiphase flow” means the flow of more than one phase (i.e., gas, solid, or liquid). The most common class of multiphase flows are the two-phase flows, including, gas-liquid flow, gas-solid flow, and liquid-solid flow.

“Net worth” means total assets minus total liabilities and is equivalent to owner’s equity.

“Net working capitol” means current assets minus current liabilities.

“Permanent sequestration” or “permanence” means the state where sequestered CO_2 will remain within the sequestration zone for at least 100 years.

“Perforation interval” means the section of wellbore that has been prepared for production by creating channels between the reservoir formation and the wellbore.

“Permeability” means the measure of a rock’s ability to transmit fluids.

“Petrophysical analysis” means the study of the fundamental chemical and physical properties of reservoir rocks and their contained fluids. The term, “petrophysics,” encompasses multiple types of rock studies, including core analysis, sample descriptions, petrography, scanning electron microscopy, well log data, and other forms of detailed laboratory data.

“Petrographical analysis” means the in-depth investigation of the chemical and physical features of a particular rock sample. A complete analysis must include macroscopic to microscopic investigations of the rock sample.

“Pore pressure” means the pressure of a fluids held within spaces between particles (i.e. pore space) in a rock.

“Pore space” means the volume of rock or soil voids that can be filled by a fluid, such as water, air, or CO_2.

“Porosity” means the relative volume of the void space in the rock that is not occupied by solid grains or minerals. The space between crystals or grains in a rock that is available to be filled with a fluid such as water, oil, or gas, is called the “pore space.”

“Post-injection site care” means appropriate monitoring and other actions (including corrective action) needed following the completion of injection to ensure permanence of sequestered CO_2.

“Precipitation kinetics” means the rates of mineral precipitation from a solution. Mineralization reactions are very sensitive to kinetic rate parameters.

"Pressure front" means the region of elevated pressure that is created by the injection of CO_2 into the subsurface. For the purposes of the GCS certification, the pressure front of a CO_2 plume refers to the region where there is the pressure differential sufficient to cause movement of injected or formation fluids out of the primary sequestration zone.

"Pressure fall-off test" means a field test conducted by ceasing injection for a time period (i.e., shutting-in the well) and monitoring pressure decay at the well. The pressure change is analyzed using pressure transient analysis, a technique based on the mathematical relationships between flow rate, pressure, and time. The information from these analyses helps determine injection potential. It can also derive permeability, reservoir boundary shape, and reservoir pressures.

"Project GHG emissions" means the GHG emissions from various activities associated with a CCS project.

"Pump test" means a field experiment in which a well is pumped at a controlled rate and water-level response (drawdown) is measured in one or more surrounding observation wells and optionally in the pumped well itself. Response data from pumping tests are used to estimate the hydraulic properties of aquifers, evaluate well performance, and identify aquifer boundaries.

"Reactive transport model" means a model of the chemical reactions between constituents (e.g., injected CO_2, formation fluids, and the reservoir rock). These models incorporate rate-limited intra-aqueous reactions, mineral dissolution and precipitation, changes in porosity and permeability due to these reactions, and multi-component gas mixtures to model and predict the impact of CO_2 and its co-injectates (e.g., hydrogen sulfide, sulfur dioxide) on aquifer acidification, the concomitant mobilization of metals, and any mineral trapping of CO_2. These models can also be used to assess corrosion of well construction materials.

"Recycled CO_2" means CO_2 that separated from oil and gas and reinjected back into a reservoir.

"Relative permeability" means the ratio of the effective permeability of a particular fluid at a particular saturation to the absolute permeability of that fluid at total saturation (dimensionless). If a single fluid is present in a rock, its relative permeability is 1.0.

"Rock compressibility" means the relative volume change of matter per unit pressure change under conditions of constant temperature. Rock compressibilities are typically displayed in psi^{-1}.

"Site closure" means the point or date, after at least 100 years and as determined by the Executive Officer following the requirements under **Section 5.2**, at which the GCS Project Operator is released from post-injection site care responsibilities.

“Seepage velocity” is the flow rate per unit cross-sectional area of an aquifer (L/time).

“Sequestration zone” means a geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project.

“Skin factor” means a dimensionless pressure drop caused by a flow restriction in the near-wellbore region, typically associated with damage during drilling and well operations.

“Specific storage” means the volume of water released from storage from a unit volume of aquifer per unit decline in hydraulic head (displayed in L^{-1}).

“Step rate test” means test in which a fluid is injected for a defined period in a series of increasing pump rates. The resulting data are used determine the maximum safe injection rate possible without fracturing the reservoir rock.

“Stratigraphic test well” means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in subsurface exploration.

“Storage coefficient” means the volume of water released from storage by a confined aquifer per unit surface area of aquifer per unit decline in hydraulic head normal to the surface and equal to the product of specific storage and the saturated thickness (dimensionless).

“Storage complex” means the storage zone and surrounding geological domain, and is composed of the sequestration zone, confining layer, and any dissipation intervals needed to dissipate excess pressure above and/or below the storage zone.

“Stratigraphy” means the classification of sedimentary rocks based on their lithologic properties and geometric relations, such as spatial distribution, depositional environment, composition, and age.

“Supercritical CO_2” means the physical state where CO_2 exhibits properties of both a gas and a liquid when its temperature and pressure exceeds the critical temperature (87.98 °F) and pressure (1,071 psi).

“System boundary” means a delineation of activities/processes that are considered part of the project when analyzing emissions from CCS projects.

“Tangible net worth” means the tangible assets that remain after deducting liabilities; such assets would not include intangibles such as goodwill and rights to patents or royalties.

“Total dissolved solids (TDS)” means inorganic salts (principally calcium, magnesium, potassium, sodium, bicarbonates, chlorides, and sulfates) and some small amounts of organic matter that are dissolved in water.

“Transmissibility” means a measure of the conductivity of the formation corrected for the viscosity of the flowing fluid. It is a coefficient associated with Darcy’s law that characterizes flow through porous media. It is equal to the coefficient of permeability (hydraulic conductivity) multiplied by the thickness of the formation.

“Transmissive fault or fracture” means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.

“True stratigraphic thickness” means the thickness of rock layer after correcting for the dip (inclination) of the layer and the deviation of the well that penetrates it. Values of true stratigraphic thickness in an area can be plotted to create an isopach map.

“True vertical depth” means the vertical distance from a point in the well (usually the current or final depth) to a point at the surface. If the well is deviated, the measurement may be different from the “measured depth.”

“True vertical thickness” means the thickness of a layer of rock measured vertically from a reference point at the surface. Values of true vertical thickness in an area can be plotted to create an isochore map.

“Tubing” or “production tubing” means any tubing used to inject or produce fluids, respectively.

“Unconfined compressive stress” is a measure of a material’s strength. The unconfined compressive strength (UCS) is the maximum axial compressive stress that a right-cylindrical sample of material can withstand under unconfined conditions. It is also known as the “uniaxial compressive strength” of a material because the application of compressive stress is only along one axis-the longitudinal axis-of the sample.

“Vadose zone” means the unsaturated zone of the subsurface above the groundwater table. The soil and rock within this zone typically contains air and water within its pore space.

“Vented emissions” means intentional or designed releases of CH_4 or CO_2 including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

"Vertical stress" means the weight of the overlying material imposed on a layer of rock. Vertical stress is the combined stress due to the total weight of rock and interstitial fluids above a specified depth.

"Viscosity" means the measure of a liquid's resistance to flow.

"Wellbore" means a hole that is drilled into the Earth's subsurface. A wellbore can be encased by materials such as steel and cement, or it may be uncased.

"Wireline" means a wire or cable that is used to deploy tools and instruments downhole and transmits data to the surface.

"Workover" means the process of performing major maintenance or remedial treatments on an injection or production well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location.

(b) Acronyms:

"API" means American Petroleum Institute
"AOR" means Area of Review.
"APCD" means Air Pollution Control District.
"AQMD" means Air Quality Management District.
"CARB" means California Air Resources Board.
"CA-GREET" means the Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model, as referred to in the LCFS regulation.
"CERCLA" means Comprehensive Environmental Response, Compensation, and Liability Act.
"ASTM" means American Society for Testing and Materials.
"CAA" means Clean Air Act.
"CCS" means Carbon Capture and Sequestration.
"CH_4" means methane.
"CIL" means casing inspection log.
"CO" means carbon monoxide.
"CO_2" means carbon dioxide.
"CO_2e" means CO_2 equivalent
"$CO_{2(aq)}$" means carbon dioxide dissolved in an aqueous solution.
"$CO_{2(g)}$" means carbon dioxide as a free gas phase.
"CO_2-EOR" means CO_2-enhanced oil recovery.
"GCS" means geologic carbon sequestration.
"DOGGR" means the California Division of Oil, Gas, and Geothermal Resources.
"GHG" means greenhouse gas.
"GPS" means global positioning system.
"LCFS" means the Low Carbon Fuel Standard (title 17, California Code of Regulations, section 95480 et seq.)

“MRR” means the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, sections 95100 et seq.)
“MT” means metric ton.
“N_2O” means nitrous oxide.
“NESHAPS” means the National Emission Standards for Hazardous Pollutants preconstruction approval under the Clean Air Act.
“NPDES” means the National Pollution Discharge Elimination System under the Clean Water Act.
“PSD” means the Prevention of Significant Deterioration program under the Clean Air Act.
“PSI” means pounds per square inch.
“RCRA” means the Resource Conservation and Recovery Act.
“SDWA” means Safe Drinking Water Act.
“SIC” means Standard Industrial Classification codes for classifying industries by a four-digit code.
“TDS” means total dissolved solids.
“TOC” means total organic carbon.
“US EPA UIC” means United States Environmental Protection Agency Underground Injection Control program[3].
“VOC” means volatile organic compound.

[3] EPA Underground Injection Control Program, 40 C.F.R. §144, §145, and §146 (2014).

B. ACCOUNTING REQUIREMENTS FOR CCS PROJECTS UNDER LCFS

1. System Boundary

The Accounting Requirements for CCS delineates a system boundary that covers all CO_2 sources, sinks, and reservoirs (SSRs) from a CCS project. All SSRs within the system boundary must be accounted for when quantifying emissions reductions from CO_2 sequestration. Typically, SSRs included in the system boundary are carbon capture and compression, CO_2 transport and CO_2 injection. Note that the injection and storage site may be geographically separate from the capture site as shown in **Figure 1**.

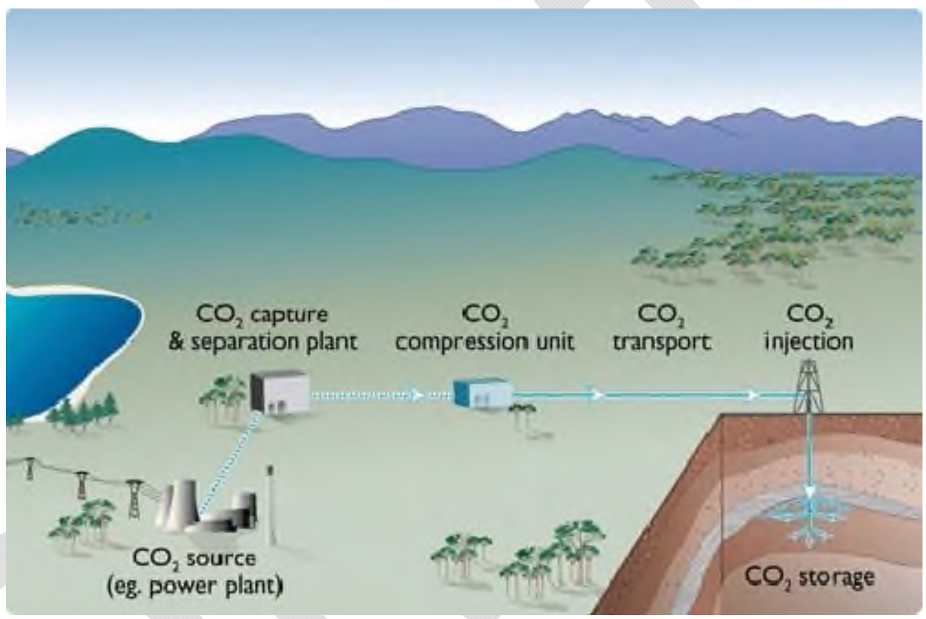

Figure 1. An example of geologic sequestration project indicating SSRs.[4]

The specific types of equipment and sources covered by the system boundary can vary by CCS project types. **Figure 2** shows the system boundary for capturing CO_2 and sequestering it in oil and gas reservoirs used for CO_2-EOR indicating which SSRs are included. Likewise **Figure 3** shows the system boundary for capturing CO_2 and sequestering it in depleted oil and gas reservoirs (not meant for oil and gas production) and saline formations.

In either case, the system boundary begins with carbon capture and ends with injection operations including CO_2 leakage. Any emissions downstream of the sequestration site (except entrained CO_2 in the case of CO_2-EOR) are excluded since they are associated with the downstream products rather than the CCS project. For example, GHG emissions associated with crude oil transport from the CO_2-EOR facility and subsequent refining are not accounted for within the project boundary.

[4]Source: Energy and Earth Resources, Department of State Development, Business and Innovation within the Victorian State Government (Australia)

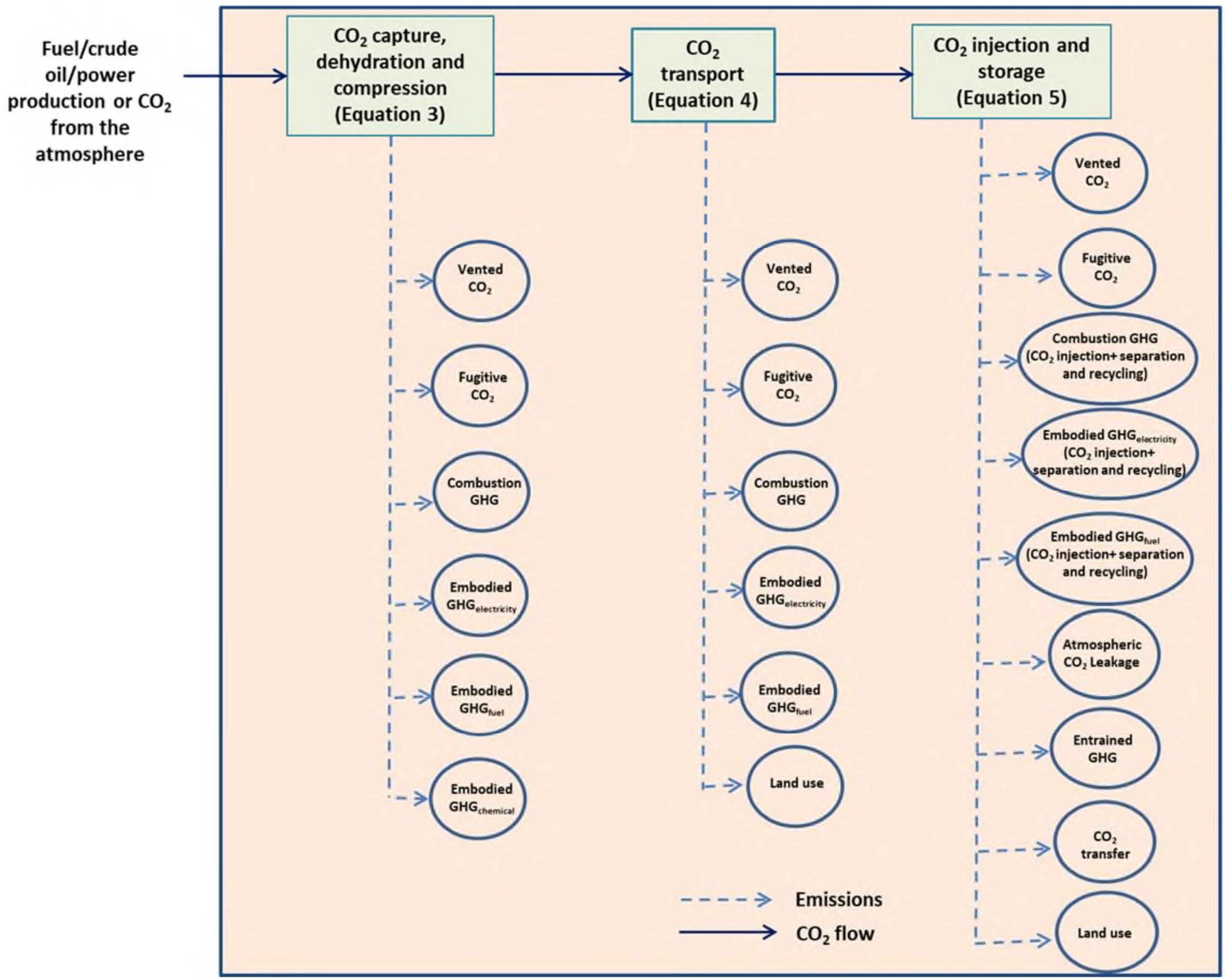

Figure 2. System boundary for CO_2 capture and sequestration in oil and gas reservoirs used for CO_2-EOR.

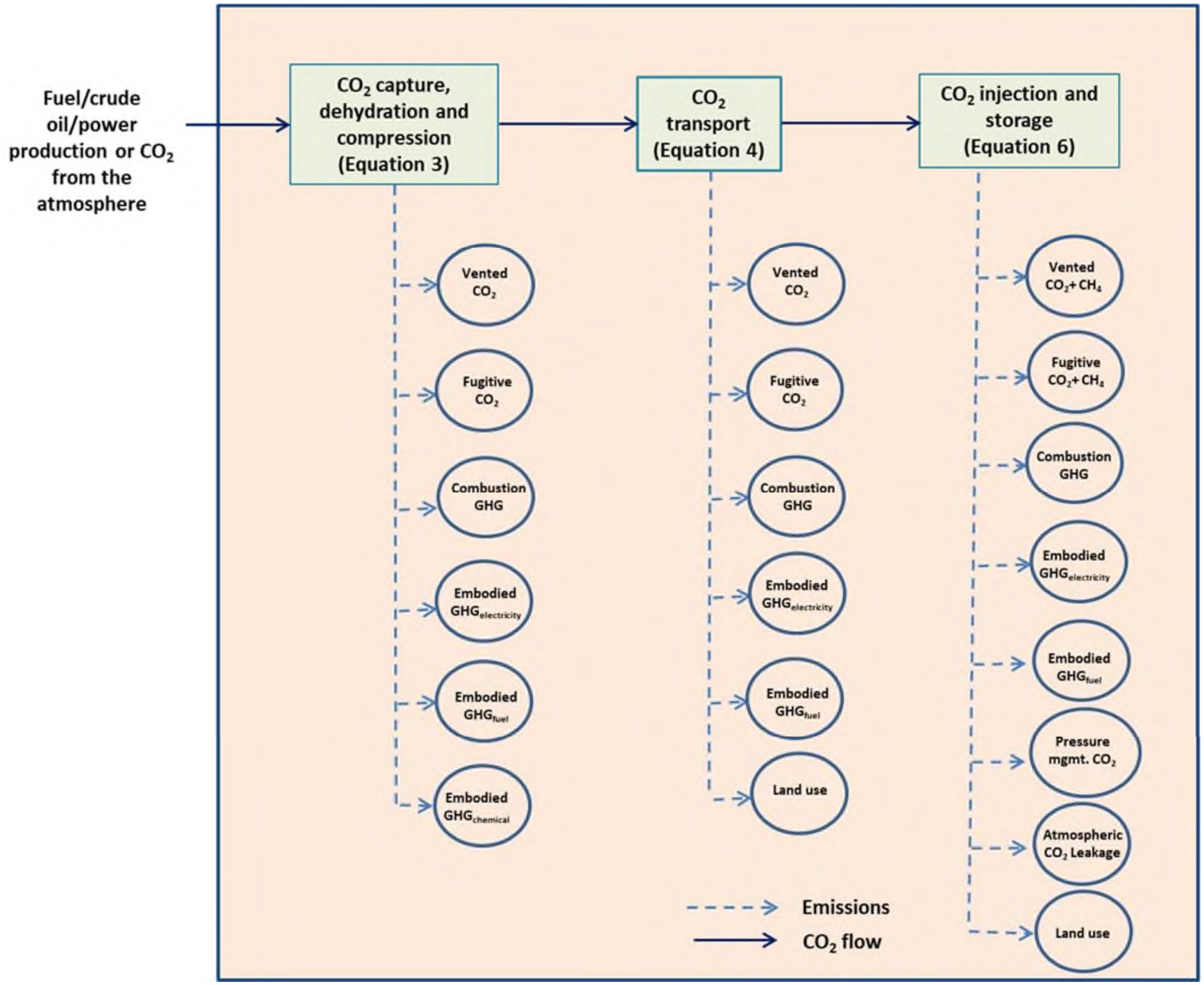

Figure 3. System boundary for CO_2 capture and sequestration in depleted oil and gas reservoirs and saline formations.

2. Quantification of Geologic Sequestration CO_2 Emission Reductions

This section describes the methodology for estimating GHG emissions reductions by sequestering CO_2 in oil and gas or saline reservoirs.

2.1. Covered Greenhouse Gas Emissions for LCFS

Under LCFS, GHG accounting relies on CA-GREET. In addition to CO_2, CH_4, and N_2O, CA-GREET treats volatile organic compounds (VOC) and carbon monoxide (CO) as GHGs because they are eventually oxidized to CO_2. In the context of CCS projects in LCFS emissions covered in this document under LCFS are CO_2, N_2O, CH_4, CO and VOC. The global warming potential values listed in the CA-GREET model are used to determine the CO_2 equivalent of emissions. If N_2O, CH_4, CO and VOC present in the CO_2 stream are sequestered during CO_2 injection, they are not included in the quantification.

2.2. Greenhouse Emissions Reductions Calculation

(a) Net annual GHG emissions reductions from CCS projects must be quantified using **Equation 1.**

$$GHG_{reduction} = CO_{2_{injected}} - GHG_{project} \tag{1}$$

Where:

$GHG_{reduction}$ = Net GHG reductions (MT CO_2e/year).

$CO_{2_{injected}}$ = Amount of injected CO_2 (MT CO_2/year). Excludes recycled CO_2 in the case of CO_2-EOR (equal to purchased CO_2 per year measured at the point of injection).

$GHG_{project}$ = Project GHG emissions (MT CO_2e/year).

If the injected CO_2 consists of CO_2 derived from various sources/facilities, a mass-balance approach must be used to assign the injected amount to the various sources of carbon capture based on metered data and contractual agreements between the CO_2 supplier and GCS project operator. CO_2 from natural underground CO_2 reservoirs must be omitted from $CO_{2_{injected}}$ in **Equation 1**.

(b) Annual project GHG emissions must be calculated using **Equation 2**. Each variable in **Equation 2** must include both direct emissions from fuel combustion and non-combustion emissions as well as upstream (indirect) emissions associated with the corresponding specific activity, and must be determined pursuant to **subsections 2(c)** through **(e)** below.

$$GHG_{project} = GHG_{capture} + GHG_{transport} + GHG_{injection} + GHG_{dLUC} \tag{2}$$

Where:

$GHG_{project}$ = Project GHG emissions (MT CO_2e/year).

$GHG_{capture}$ = GHG emissions associated with carbon capture, dehydration, and compression (MT CO_2e/year).

$GHG_{transport}$ = GHG from CO_2 transport (MT CO_2e/year). Transport can be by pipeline, ships, rail, or trucks.

$GHG_{injection}$ = GHG emissions from injection operations (MT CO_2e/year).

GHG_{dLUC} = GHG emissions from direct land use change (MT CO_2e/year).

(c) Annual GHG emissions from carbon capture, dehydration and compression must be calculated according to **Equation 3**. GHG emissions from fuel combustion and electricity use must be determined using emission factors available in CA-GREET. If an emission factor for a particular fuel is not available in CA-GREET, applicants must refer to **Table A1** in Appendix.[5] $CO_{2_{vent}}$ and $CO_{2_{fugitive}}$ in **Equation 3** are zero if the CO_2 is of biogenic origin such as from sugar fermentation, or derived from direct air capture.

$$GHG_{capture} = CO_{2_{vent}} + CO_{2_{fugitive}} + EmbodiedGHG_{combustion} + EmbodiedGHG_{electricity} + GHG_{fuel} + EmbodiedGHG_{chemical} \quad (3)$$

Where:

$GHG_{capture}$ = GHG emissions from capture, dehydration, and compression (MT CO_2e /year).

$CO_{2_{vent}}$ = CO_2 vented during capture, dehydration, and compression (MT CO_2/year).

$CO_{2_{fugitive}}$ = Fugitive CO_2 emissions from equipment used in capture, dehydration, and compression (MT CO_2/year).

$GHG_{combustion}$ = GHG emissions from fuel combustion in stationary equipment (MT CO_2e /year).

$EmbodiedGHG_{electricity}$ = Embodied (upstream) GHG emissions from electricity use (MT/ CO_2e year).

$EmbodiedGHG_{fuel}$ = Embodied (upstream) GHG emissions of fuel used in stationary equipment (MT/ CO_2e year).

$EmbodiedGHG_{chemical}$ = Embodied (upstream) GHG emissions from chemicals used in carbon capture, including replacements from loss/deterioration (MT CO_2e /year). Depending on the technology used, carbon capture may involve the use of

[5] Combustion emission factors provided in the CA-GREET and Table A1 may differ from the emission factors mentioned in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (CARB).

chemicals such as monoethanolamine (MEA), NaOH, and activated carbon.

GHG emissions from fuel combustion ($GHG_{combustion}$) must be calculated using the amounts of fuels and purchased steam used and their corresponding emission factors provided in the CA-GREET model. If specific emission factors are not available in CA-GREET, refer to emission factors provided in **Table A1**.

Embodied GHG emission of electricity ($EmbodiedGHG_{electricity}$) must be calculated using electricity emission factors in the CA-GREET model.

Embodied GHG emissions of chemicals ($EmbodiedGHG_{chemical}$) must be calculated using the CA-GREET model or an equivalent method if the chemical in question is not modelled in CA-GREET.

Embodied (upstream) GHG emissions of fuel ($EmbodiedGHG_{fuel}$) must be calculated using the CA-GREET model, or an equivalent method if the fuel in question is not modelled in CA-GREET.

Fugitive CO_2 emissions will be calculated using the equipment count method and vented CO_2 emissions will be calculated using the event-based approach described in **Appendix A**.

If the injected CO_2 comes from various sources, $GHG_{capture}$ in **Equation 3** must be calculated and summed together for each source.

(d) Annual GHG emissions from CO_2 transport must be calculated using **Equation 4.** $CO_{2_{vent}}$ and $CO_{2_{fugitive}}$ in **Equation 4** are zero if the CO_2 is of biogenic origin, such as from sugar fermentation, or derived from direct air capture.

$$GHG_{transport} = CO_{2_{vent}} + CO_{2_{fugitive}} + GHG_{combustion} + EmbodiedGHG_{electricity} + EmbodiedGHG_{fuel} \quad (4)$$

Where:

$GHG_{transport}$ = GHG emissions from CO_2 transport (MT CO_2e/year).

$CO_{2_{vent}}$ = CO_2 vented during CO_2 transport (MT CO_2/year).

$CO_{2_{fugitive}}$ = Fugitive CO_2 emissions from equipment used in CO_2 transport (MT CO_2/year).

$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment (MT CO_2e/year) used in CO_2 transport.

$EmbodiedGHG_{electricity}$ = Embodied (upstream) GHG emissions from electricity use (MT CO_2e /year) in CO_2 transport.

$EmbodiedGHG_{fuel}$
= Embodied (upstream) GHG emissions of fuels used in CO_2 transport (MT CO_2e /year).

Fugitive CO_2 emissions can be calculated using the equipment count method and vented CO_2 emissions must be calculated using the event-based approach described in **Appendix A**. Alternatively, combined vented and fugitive CO_2 emissions can be calculated using a mass balance approach by subtracting the amount CO_2 delivered at the injection site from the metered CO_2 delivered into pipeline or transferred to other modes of transport.

If a pipeline carries CO_2 to multiple geological sites or serves multiple uses, CO_2 transport emissions must be prorated using the mass-based allocation method and assigned to the CCS project under consideration.

If the injected CO_2 comes via two or more different transport modes, $GHG_{transport}$ in **Equation 4** must be calculated and summed together for each transport mode.

(e) Annual GHG emissions from CO_2 injection operations must be calculated using **Equation 5** for CO_2-EOR and **Equation 6** for depleted oil and gas reservoirs and saline formations.

Entrained CO_2 emissions in **Equation 5** are calculated using the formula provided in **Equation D1** in **Appendix D**.

GHG Emissions from fuel combustion, electricity use and embodied (upstream) emissions of fuels must be restricted to CO_2 injection, separation and recycling operations only. GHG emissions associated with fuel combustion, electricity use and embodied (upstream) emissions of fuels used for other activities at the CO_2-EOR site are excluded from the credit calculation because they are assigned to the crude production pathway.

$$\begin{aligned} GHG_{injection} = {} & GHG_{combustion} + EmbodiedGHG_{electricity} \\ & + EmbodiedGHG_{fuel} + CO_{2_{vent}} + CO_{2_{fugitive}} + CO_{2_{entrained}} \\ & + CO_{2_{leakage}} + CO_{2_{transfer}} \end{aligned} \qquad (5)$$

Where:

$GHG_{injection}$ = GHG emissions in CO_2e associated with injection operations in CO_2-EOR (MT CO_2e/year).

$GHG_{combustion}$
= GHG emissions from fuel combustion at stationary equipment used in CO_2 injection, separation and recycling (MT CO_2e/year).

$EmbodiedGHG_{electricity}$

	=	Embodied (upstream) GHG emissions from electricity use in CO_2 injection, separation and recycling (MT CO_2e/year).
$EmbodiedGHG_{fuel}$	=	Embodied (upstream) GHG emissions of fuels used (excluding electricity) in CO_2 injection, separation, and recycling (MT CO_2e/year).
$CO_{2_{vent}}$	=	CO_2 emissions from venting (MT CO_2/year) including biogenic CO_2 and CO_2 from direct air capture.
$CO_{2_{fugitive}}$	=	Fugitive CO_2 emissions from surface equipment (MT CO_2/year) including biogenic CO_2 and CO_2 from direct air capture.
$CO_{2_{entrained}}$	=	Entrained CO_2 in produced water, natural gas, and crude oil downstream of a separator unit (MT CO_2/year).Excludes entrained CO_2 if it is reinjected into reservoirs.
$CO_{2_{leakage}}$	=	Atmospheric CO_2 leakage from the sequestration zone (MT CO_2/year).
$CO_{2_{transfer}}$	=	Intentional transfer of stored CO_2 outside of the project boundary (MT CO_2/year).

And:

$$GHG_{injection} = GHG_{combustion} + EmbodiedGHG_{electricity} + EmbodiedGHG_{fuel} + GHG_{vent} + CO_{2_{fugitive}} + CO_{2_{leakage}} \tag{6}$$

Where:

$GHG_{injection}$	=	GHG emissions associated with CO_2 injection operations (MT CO_2e/year).
$GHG_{combustion}$	=	GHG emissions from stationary combustion equipment (MT CO_2e/year).
$EmbodiedGHG_{electricity}$	=	Embodied (upstream) GHG emissions from electricity use (MT CO_2e/year).
$EmbodiedGHG_{fuel}$	=	Embodied (upstream) GHG emissions of fuels excluding electricity (MT CO_2e/year).
GHG_{vent}	=	CO_2 and CH_4 vented from equipment located between the injection flow meter and the injection wellhead (MT CO_2e/year).
$GHG_{pressure}$	=	CO_2 and CH_4 emissions from pressure management activities including brine production (MT CO_2e/year).
$CO_{2_{fugitive}}$	=	Fugitive CO_2 emissions from surface equipment per year (MT CO_2/year).

$CO_{2_{leakage}}$ = Atmospheric CO_2 leakage from the sequestration zone (MT CO_{2e}/year)

There are planned and unplanned venting events in CO_2 injection operations. For CO_2-EOR, these must include any CO_2 vented from the last batch of crude oil taken out of the ground, instead of injecting the recovered CO_2 back into wells at the end of EOR project completion, and any CO_2 blowdown.

Vented CO_2 emissions from CO_2-EOR must be determined for each applicable venting source using the methods described in **Appendix B**. In the case of CO_2 injection operations in depleted oil and gas or saline reservoirs**,** vented CO_2 emissions from surface facilities must be calculated using the event-based approach described in **Appendix A(2)**. This must include CO_2/CH_4 releases from pressure management including brine production.

In the case of CO_2-EOR operations, fugitive CO_2 emissions must be calculated using either leak detection and leaker emission factors, or using population count and emission factors as described in **Appendix B(14)**. Fugitive CO_2 emissions occur from fittings, flanges, valves, connectors, meters, and headers associated with CO_2-EOR operations. In the case of CO_2 injection operations in depleted oil and gas reservoirs/saline formations, fugitive CO_2 and CH_4 emissions from equipment must be calculated using the equipment count method described in **Appendix A(1)**.

In the case of CO_2-EOR operations, CO_2 can remain in water, natural gas and crude oil after they are separated from produced CO_2 in separators for either sales or disposal/injection of water. CO_2 from these product streams will eventually be released and must be calculated using **Equation D1** in **Appendix D**.

To be conservative, $CO_{2_{leakage}}$ must be considered to be equal to the detection limit of the equipment used to detect leaks in the project's monitoring plan, absent any detected leaks.

In cases where atmospheric or subsurface leakage has occurred, $CO_{2_{leakage}}$ must be calculated using a method identified in the project's monitoring plan.

In the event the stored CO_2 is intentionally released via decompression and transferred to other EOR locations it must be counted as emissions and included in $CO_{2_{transfer}}$.

(f) Installation of pipelines and construction of CO_2 injection sites can cause changes in above and belowground carbon stock depending on the type of land use where these facilities are going to be located. In such a case, direct land use change GHG emissions must be calculated using land use change emission factors utilized in the Global Trade Assessment Project model or using similar CARB-approved land use change emission factors. Indirect land use change GHG emissions are omitted from the Accounting Requirements since they are considered negligible. Direct land use change GHG emissions must be amortized over a period of 30 years.

C. PERMANENCE REQUIREMENTS FOR GEOLOGIC SEQUESTRATION

1. Permanence Certification of Geologic Carbon Sequestration Projects

1.1. Application and Certification

(a) The GCS Project Operator may apply for Executive Officer certification that their GCS project is capable of permanent carbon sequestration pursuant to the Permanence Requirements. The application must include the third party review, data, and plans specified in **Sections 1.1.1** and **1.1.2**.

(b) If after reviewing the submitted material, the Executive Officer determines that the GCS project meets the permanence requirements of sequestering carbon pursuant to the Permanence Requirements, the Executive Officer shall post an initial determination along with the application package for public comment for 15 days, address those comments if considered valid, and then issue a Permanence Certification for the project by executive order.

1.1.1. Third Party Review

(a) Prior to submittal of a GCS project application to the Executive Officer for Permanence Certification, the operator must have their application reviewed by a party or parties that are mutually agreed upon by the Executive Officer and the applicant. The applicant is responsible for all costs of the application review.

(b) The third party reviewer must certify that the data submitted as part of the application in **Section 1.1.2** are true, accurate, and complete.

(c) The third party reviewer must certify that the plans submitted as part of the application in **Section 1.1.2** are sufficiently robust that, in their professional judgment, the GCS project is able to meet the permanence requirements for carbon sequestration.

(d) The third party reviewer must certify that the Site-Based Risk Assessment submitted as part of the application in **Section 1.1.2** is accurate and complete, and that the risks identified are either sufficiently monitored or sufficiently remediated in the Emergency and Remedial Response Plan submitted in the application.

1.1.2. Certification Application Materials

All applications for permanence certification pursuant to the Permanence Requirements must include the following materials:

(a) General Information Requirements:

(1) Statement of the primary purpose of the project.

(2) A brief description of the nature of the business.

(3) The name, mailing address, and latitude and longitude of the GCS project or well for which the Permanence Certification is submitted.

(4) The operator's name, address, telephone number, ownership status, and status as a federal, state, private, public, or other entity.

(5) The activities conducted by the operator which would require it to obtain permits under RCRA, the U.S. EPA UIC program, the NPDES program under SDWA, or the PSD program under CAA.

(6) The activities conducted by the operator that would require it to obtain any drilling permits, valid access agreements, or any encroachment permits under county or city guidelines, or any federal, state, or local air, water, or restricted land use operating permits.

(7) A listing of all permits or construction approvals received or applied for and their status under any of the following programs:

(A) Hazardous Waste Management program under RCRA;

(B) U.S. EPA UIC program under SDWA;

(C) NPDES program under SDWA;

(D) PSD program under CAA;

(E) Nonattainment program under CAA;

(F) NESHAPS preconstruction approval under CAA;

(G) Dredge and fill permits under section 404 of Clean Water Act;

(H) Other relevant environmental permits such as federal, state, county, or city permits.

(b) Application for Site Approval:

(1) Site-Based Risk Assessment pursuant to **Section 2.2**, including a Risk Management Plan following **subsection 2.2(c)**;

(2) A Geologic Evaluation pursuant to **Section 2.3**, including a Formation Testing and Well Logging Plan following **Section 2.3.1**;

(3) An Area of Review (AOR) Delineation and Corrective Action Plan pursuant to **Section 2.4**, including a description of the computational model used following **Section 2.4.1** and the results of the AOR delineation modeling following **Section 2.4.2**;

(4) Baseline Surface and Near-Surface Testing Plan pursuant to **Section 2.5**;

(5) A Testing and Monitoring Plan pursuant to **Section 4.**1, including plans for mechanical integrity testing (**Section 4.2**), emissions monitoring (**Section 4.3.1**), and monitoring, measurement, and verification of containment (**Section 4.3.2**);

(6) A Well Plugging Plan pursuant to **Section 5.1**;

(7) A Post-Injection Site Care and Site Closure Plan pursuant to **Section 5.2**;

(8) An Emergency and Remedial Response Plan pursuant to **Section 6**;

(9) A Financial responsibility demonstration pursuant to **Section 7**;

(10) A Legal understanding demonstration pursuant to **Section 9**; and

(11) Any other plans or information required by the Executive Officer.

(c) Site approval will be implemented by an executive order from CARB.

(d) Application for Injection Approval:

(1) Formation testing and well logging report pursuant to **subsection 2.3.1(d)(l)**;

(2) Corrective action report pursuant to **Section 2.4.4**;

(3) Baseline surface and near-surface testing report pursuant to **subsection 2.5(f)**;

(4) Well construction and pre-injection testing report pursuant to **Sections 3.1** and **3.2**;

(5) Any updates to the AOR and Corrective Action Plan, Testing and Monitoring Plan, Well Plugging Plan, and Post-Injection Site Care and Site Closure Plan; and

(6) Any other information required by the Executive Officer that is necessary to evaluate the application for site approval.

(e) Injection approval and Permanence Certification will be implemented by an executive order from CARB.

1.1.3. Reporting

1.1.3.1. Electronic Reporting

(a) The GCS Project Operator must submit to the Executive Officer any reports, submittals, notifications, and records made and maintained by the operator under this Permanence Certification in an electronic format. The accuracy of all electronic submissions must be attested to at the time of submission.

(b) The GCS Project Operator is solely responsible for ensuring that the Executive Officer receives its reports, submittals, notifications, and records as required in this section. The Executive Officer must not deem an electronically submitted report to be valid unless the report is accompanied by a digital signature that meets the requirements of California Code of Regulations, title 2, sections 22000 *et seq*.

1.1.3.2. Quarterly Reporting

TO BE UPDATED

1.1.3.3. Annual Reporting

TO BE UPDATED

1.1.3.4. Advanced Notice Reporting

(a) Well tests: The GCS Project Operator must give at least 30 days advance written notice to the Executive Officer of any planned mechanical integrity test or workover.

(b) Planned Changes: The GCS Project Operator must give written notice to the Executive Officer, as soon as possible, of any planned physical alterations or additions to the injection project other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid must be submitted to the Executive Officer for review and written approval at least 30 days prior to injection; this approval may result in a GCS project certification modification.

1.1.3.5. 24-Hour Reporting

(a) The GCS Project Operator must report to (1) the Executive Officer, (2) DOGGR, and any relevant local or state agency any Permanence Certification noncompliance which may endanger public health or the environment or any events that require implementation of actions in the Emergency and Remedial

Response Plan. Any information must be provided orally and in an electronic format within 24 hours from the time the GCS Project Operator becomes aware of the circumstances. Such verbal reports must include, but not be limited to the following information:

(1) Any evidence that the injected CO_2 stream or associated pressure front may endanger public health and the environment, or any monitoring or other information which indicates that any contaminant may cause endangerment to public health and the environment;

(2) Any noncompliance with a Permanence Certification condition, or malfunction of the injection system, which may cause fluid migration out of the primary injection zone that is likely to reach the atmosphere;

(3) Any triggering of the shut-off system required in **Section 3.4** (e.g., downhole or at the surface);

(4) Any failure to maintain mechanical integrity;

(5) Pursuant to compliance with the testing and monitoring requirements in **Section 4.3.2**, any release of CO_2 outside the primary injection zone to the atmosphere; and

(6) Actions taken to implement appropriate protocols outlined in the Emergency Remedial Response Plan.

(b) A written submission must be provided to the Executive Officer within five business days of the time the GCS Project Operator becomes aware of the circumstances described in **subsection *1.1.3.5*(a)**. The submission must contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan, and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

1.1.3.6. Additional Reporting

(a) Noncompliance: The GCS Project Operator must report all instances of noncompliance not otherwise reported with the next quarterly monitoring report. The reports must contain the information listed in **subsection *1.1.3.5*(b)**.

(b) Other information: When the GCS Project Operator becomes aware of failure to submit any relevant facts in the Permanence Certification or that incorrect information was submitted in a Permanence Certification or in any report to the

Executive Officer, the GCS Project Operator must submit such facts or corrected information within 10 days.

1.1.4. Recordkeeping

The GCS Project Operator must retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by the Permanence Certification (including records from pre-injection, active injection, and post-injection phases) for a period of 10 years after site closure.

(a) The GCS Project Operator must maintain records of all data required to complete the Permanence Certification and any supplemental information (e.g. modeling inputs for AOR delineations and reevaluations, plan modifications, etc.) submitted under **Section 1.1.2**, for a period of at least 10 years after site closure.

(b) The GCS Project Operator must retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(c) The retention periods specified in **subsections 1.1.4(a)** and **(b)** may be extended by request of the Executive Officer at any time. The GCS Project Operator must continue to retain records after the retention period specified in **subsections 1.1.4(a)** and **(b)** or any requested extension thereof expires unless the operator delivers the records to, or obtains written approval from, the Executive Officer to discard the records.

1.2. Terms and Conditions

(a) Any changes to the operational parameters of a Permanence Certification are subject to approval by the Executive Officer and must be noted in either an addendum to the a Permanence Certification or a revised a Permanence Certification. All GCS injection operations must cease until the new operation parameters are consistent with the terms and conditions of the revised GCS project certification.

(b) The Permanence Certification is non-transferable.

(c) Permanence Certification must expire, and be deemed null and void, upon the first day following 24 consecutive months of no injection at the GSC project, and a new approval process and re-certification would be required prior to restarting injection.

2. Site Characterization

2.1. Minimum Site Selection Criteria

(a) As part of the application for site approval, the GCS Project Operator must demonstrate that the geologic system comprises:

(1) A sequestration zone of sufficient areal extent, thickness, porosity, permeability, and injectivity to receive the total anticipated volume of the CO_2 stream;

(2) A minimum injection depth of 800 m (2,600 ft).[6]

(3) A primary confining layer free of transmissive faults or fractures and of sufficient areal extent, integrity, thickness, an

(4) d ductility to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining layer;

(5) A minimum of one additional permeable stratum (dissipation interval) situated directly above the primary sequestration zone and confining layer (storage complex), with at least one impermeable confining layer (secondary confining layer) between the storage complex and the dissipation interval. The purpose of the dissipation interval is to (1) dissipate any excess pressure caused by CO_2 injection, (2) impede vertical migration of CO_2 and/or brine to the surface and atmosphere via potential leakage paths, and (3) provide additional opportunities for monitoring, measurement, and verification of containment.

(6) Depending on the distance between the sequestration zone and basement rock, the Executive Officer may require the GCS Project Operator to identify and characterize additional dissipation interval(s) below the storage complex to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the injection zone.

2.2. Risk Assessment

(a) As part of the application for site approval, the GCS Project Operator must complete a Site-Based Risk Assessment that describes the potential pathways for leaks or migration of CO_2 out of the sequestration zone from the GCS project and the potential scenarios that could occur as a result.

(b) At a minimum the risk assessment must examine the scenarios in the Emergency and Remedial Response Plan under **subsection 6.1(a)**. Any other risks that could be reasonably anticipated must be included.

(c) The GCS Project Operator must develop and submit Risk Management Plan (RMP) with the Site-Based Risk Assessment that documents the results of

[6] NEEDS REFERENCE

the risk analysis. The RMP must summarize the activities that were evaluated for risk, what those risks are, how they are ranked, and the steps the GCS Project Operator will take to manage, monitor, avoid, or minimize those risks. Any risk scenarios identified as important but not included in the Emergency and Remedial Response Plan must be included in the RMP.

(d) The operator must use appropriate tools to characterize risks by combining the assessment of the probability of occurrence and the magnitude of the adverse impacts of identified project risk scenarios. Risk scenarios identified as part of this assessment must be classified according to probability of occurrence during a 100-year period: remote (less than one percent probability of occurrence over 100 years), unlikely (one to five percent probability of occurrence over 100 years), or possible (more than five percent probability of occurrence over 100 years). The magnitude of the adverse impacts of the risk scenarios identified as part of this assessment must be classified as having a consequence that is insubstantial, substantial, or catastrophic. Any classification of risk probability or consequence must be accompanied by a sufficient explanation.

(e) Any risk scenarios of possible probability of occurrence and substantial or catastrophic magnitude of adverse impacts on environment, health, and safety, or of possible or unlikely probability and catastrophic magnitude of adverse impacts on environment, health, and safety, must be mitigated. For example, using the scales in **subsection 2.2(d)**, any risks assessed must be mitigated if their consequence is catastrophic and their likelihood is more than remote, or if their consequence is substantial and their likelihood is possible. They must be mitigated from red to yellow as in **Table 1**, below. Any GCS project with risks in red that cannot be mitigated to yellow must not be granted GCS certification.

Table 1. Risk classification and response.

Risk	Insubstantial	Substantial	Catastrophic
Possible (>5%)	No mitigation, Plan required	Mitigation, Plan required	Mitigation, Plan required
Unlikely (1-5%)	No mitigation, No plan	No mitigation, Plan required	Mitigation, Plan required
Remote (<1%)	No mitigation, No plan	No mitigation, Plan required	No mitigation, Plan required

2.3. Geologic and Hydrologic Evaluation Requirement

(a) As part of the application for site approval, the GCS Project Operator must demonstrate that the selected sequestration reservoir possesses sufficient volume and injectivity to contain the proposed storage volume of CO_2 and that the injected fluid will not migrate out of the approved sequestration zone through geologic structures, including faults, fractures, and fissures.

(b) The geologic characterization requires information on the lithology, structure, hydrogeologic, and geomechanical properties of the proposed sequestration reservoir, as well as the over- and underlying formations where potential gas or fluid migration could occur, following **subsection 2.3(c)**.

(c) GCS Project Operators are required to submit, with the application for site approval, an evaluation of the geological and hydrological characteristics of the sequestration zone and confining layer derived from academic journals, historical records, laboratory and field data such as geologic core samples, outcrop data, well logs, two- and three-dimensional seismic surveys, and names and lithologic descriptions. The GCS Project Operator must submit the following information:

(1) Regional geologic information:

(A) A brief synopsis of the geologic history of the GCS project site;

(B) Porosity, permeability, lithofacies, depositional environment, and the geologic names and ages of formations;

(C) Regional hydrogeology of the sequestration zone, including groundwater flow direction, seepage velocity, and flow patterns; and

(D) Structural geology of the regional area, including faults and fault orientations, the presence and trends of folds, and whether these structures transect the sequestration formation and/or confining layer.

(2) Site-specific geologic and hydrogeologic information:

(A) Depth interval of confining layer and sequestration zone below ground surface and depth interval of planned perforation interval;

(B) Lithologic description from core or hand samples, including petrology, mineralogy, grain size, sorting or grading, cementation and dissolution features, and lithofacies or geologic rock name for both the confining and sequestration zone;

(C) Structural geology of the local area including faults and fault orientations, the presence and trends of folds, and whether these structures transect the sequestration formation and/or confining layer;

(D) Confining and sequestration zone thickness, as well as total thicknesses of both the confining layer and the sequestration reservoir, thicknesses of any high permeability or porosity intervals in the sequestration zone (if applicable), and thicknesses of planned perforated interval(s);

(E) Porosity, permeability, and capillary pressure of the sequestration zone and confining layer and perforation interval. These data must be used in the calculation of the following properties of the sequestration zone and confining layer:

1. Hydraulic conductivity;

2. Specific storage; and

3. Storage coefficient.

(3) Site-specific geomechanical and petrophysical information:

(A) Fracture pressure of the sequestration and confining layer, and the corresponding fracture gradients determined via step rate or leak-off tests performed in the wellbore;

(B) Rock compressibility, or a similar estimation of the measure of rock strength, for the confining and sequestration zone;

(C) Rock strength and the ductility of the confining layer. Rock strength is usually determined by performing a triaxial load test of the uniaxial compressive strength (*UCS*) on a core sample. Ductility and rock strength must be assessed via the following equations:

(a) Ductility of the confining layer must be calculated using the following brittleness index (*BRI*):

$$BRI = \frac{UCS}{UCS_{NC}} \quad (7)$$

Where *UCS* is the unconfined compressive strength of the confining layer as measured from intact samples, and the UCS_{NC} is the confining layer's compressive strength if it was normally consolidated, as measured from remolded samples that are normally reconsolidated;

(b) *UCS* can also be estimated from the pressure wave velocity (V_p) through intact samples or measured *in situ* within the wellbore via the equation:

$$\log(UCS) = -6.36 + \log(0.86V_p - 1172) \quad (8)$$

(c) The UCS_{NC} can also be estimated from the effective vertical stress (σ'), where:

$$UCS_{NC} = 0.5\sigma' \tag{9}$$

If *BRI* < 2, the confining layer is sufficiently ductile to anneal any discontinuities. If *BRI* > 2, discontinuities may be open.

(D) Pore pressure, or the measure of *in situ* fluid pressure, formation temperature.

(E) Estimation of the injection volume and the maximum allowable injection rate and pressure, such that neither the confining layer nor the sequestration zone hydraulically fracture during injection, must be based on step rate test results as in **subsection 2.3.1(h)**.

(4) Injectivity and pump tests of the sequestration zone based on CO_2 reservoir flow modeling using information determined from **subsection 2.3.1(i)**.

(5) Geologic characteristics of any secondary confining layers above the primary confining layer and below the sequestration zone, as well as characteristics of any dissipation intervals above and below the target sequestration and confining layers.

(6) The location, orientation, and properties of known or suspected geologic structures including faults and fractures that may transect the confining layer (transmissive faults) in the AOR and a determination by the GCS Project Operator that they would not interfere with containment, supported by information including but not limited to:

(F) Location and characteristics of the fault or fracture, such as the geometry, depth, fault displacement, and units juxtaposed by fault;

(G) Formations intersected or transected by the fault or fracture;

(H) Any information on faults or fractures in the lower confining layer; and

(I) Any methods and results of fault stability analyses and comparison to anticipated or modeled pressures during injection;

(7) An evaluation of the seismic history of the proposed sequestration site, including the date, magnitude, depth, and location of the epicenter of seismic sources and a determination that the seismicity would not cause a catastrophic loss of containment, either by breaching the integrity of the well or the sequestration formation, following a risk assessment pursuant to **subsection 2.2(e)**;

(8) A tabulation of readily available information on all saline and freshwater aquifers and springs in the AOR. This information must include:

(A) The numbers, thicknesses, and lithologies of freshwater aquifers, including interbedded and low permeability zones;

(B) Water quality such as TDS, alkalinity, pH, dissolved trace metals, and TOC;

(C) The deepest depth of freshwater aquifers;

(D) Whether any freshwater aquifers in the AOR are currently accessed for human use; and

(E) The location and distance to nearest water supply well and nearest downgradient water supply well, as well as any water wells and springs in the AOR.

(9) Geochemical data on subsurface formations and formation fluids in the AOR, including:

(A) Reservoir fluid data for the sequestration zone, such as TDS, dynamic viscosity, density, temperature, pH, and information on the potentiometric surface, if available;

(B) Characteristics of any aquifers directly above or below the sequestration zone, if applicable, including TDS, temperature, and information on the potentiometric surface, if available; and

(C) For CO_2-EOR and depleted oil and gas reservoir sites, data such as oil gravity and viscosity, presence and concentrations of non-hydrocarbon components in the associated gas (e.g. hydrogen sulfide), and gas specific gravity.

(10) The location and description of any mineral deposits or other natural resources beneath or near the AOR, including but not limited to stone, sand, clay, gravel, coal, oil, and natural gas.

(d) Site-specific maps and cross-sections, including:

(1) Geologic and topographic maps and cross-sections illustrating regional geology, hydrogeology, and geologic structure of the local area;

(2) Maps and stratigraphic cross-sections indicating the general vertical and lateral limits of all freshwater aquifers, water wells, and springs within the

AOR, their positions relative to the sequestration zone, and the direction of shallow groundwater movement, where known;

(3) Structural contour, isopach, and isochore maps of the sequestration and confining layers in the AOR including all faults and fractures, as well as any lateral containment features;

(4) Stratigraphic columns or cross-sections of the regional basin showing lateral continuity of sequestration and confining layer, as well as the lack of any significant compartmentalization or heterogeneity in the sequestration zone that could inhibit proposed injection volumes;

(5) Representative electric log to a depth below the sequestration reservoir and lower confining layer or dissipation interval(s) identifying all geologic units, formations, freshwater aquifers, and oil or gas zones. If CO_2 injection is for CO_2-EOR, the electric log must extend to a depth below the deepest producing zone;

(6) At least one cross-section in the AOR through the injection well;

(7) Maps showing the locations of any seismic lines and cross-sections; and

(8) Maps showing any known mineral deposits or natural resources within the AOR.

(e) Any additional information requested by the Executive Officer that is necessary to complete the geological and hydrogeological site evaluation.

2.3.1. Formation Testing and Well Logging Program

(a) As part of the application for site approval, the GCS Project Operator must submit a Formation Testing and Well Logging Plan. The plan must demonstrate to the Executive Officer how the GCS Project Operator will collect the geologic and hydrogeologic data required to show that the selected sequestration zone and confining layer are suitable for receiving and containing injected.

(b) This section provides guidance on the formation testing and well logging activities that the GCS Project Operator must conduct to generate the information and data required to confirm that the storage complex is able to meet the permanence requirements for carbon sequestration, as required in **Section 1.1.2.**

(c) For new GCS projects, these testing and logging activities may be undertaken during and after drilling of a stratigraphic test well, or during and after the drilling and construction of any new injection, production, or monitoring well.

(d) For a CO_2 injection well to be transitioned from a pre-existing injection, monitoring, stratigraphic test, or production well, the testing and logging information can be provided from previous and ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well.

(e) Well logging requirements:

(1) During the drilling and construction of a GCS project injection well, the GCS Project Operator must run appropriate logs, conduct surveys, and perform tests to determine or verify the depth, thickness, porosity, permeability, lithology, and salinity of all relevant geologic formations.

(2) Well logging activities must be used to supplement data on the geologic and hydrogeologic properties of relevant subsurface formations collected during initial site characterization and to support building a conceptual understanding of the site, conducting the AOR determination, and designing the GCS project.

(3) Well logging results must also be used to establish baseline data against which to compare to future measurements under **Section 2.5**, and to ensure conformance with the injection well construction requirements under **Section 3.1**.

(4) Before installation of the surface casing and the long string casing, the GCS Project Operator must perform:

(A) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Executive Officer requires for the given geology; and

(B) A series of tests to determine cement quality following procedures outlined in **subsection 3.2(a)**.

(C) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells pursuant to **subsection 3.2(a)(4)** and **Section 6.2**.

(f) Core analyses:

(1) The GCS Project Operator must take whole cores or sidewall cores of the sequestration and confining layers, and formation fluid samples from the sequestration zone, during drilling and prior to well construction, and must submit to the Executive Officer a detailed report prepared by an experienced log analyst that includes: well log data and analyses (including the logs themselves), core analyses, and formation fluid sample information.

(2) Information from cores must be used to refine site characterization data submitted pursuant to **Section 1.1.2**.

(3) The Executive Officer may accept information on cores from nearby wells if the GCS Project Operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well.

(4) Core logs must include descriptions or indications of the following characteristics: lithology, thickness, grain size, sedimentary structures, diagenetic features, geologic contacts, textural maturity, oil staining, fracturing, and porosity.

(5) Laboratory analysis of cores must include petrology and mineralogy, petrophysical properties, and geomechanical properties, including but not limited to, relative permeability, capillary pressure, fluid compatibility, wettability, and pore volume compressibility.

(6) The Executive Officer may require the GCS Project Operator to take core samples of other formations in the wellbore, such as dissipation intervals or secondary confining layers in the stratigraphic column, in order to characterize the mitigation potential of over- and underlying geologic formations.

(g) Characterization of sequestration formation fluid chemical and physical properties and downhole conditions:

(1) The GCS Project Operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the sequestration zone.

(2) The GCS Project Operator must submit the results of downhole analyses and any laboratory results on samples, including quality assurance samples (e.g., blanks, duplicates, matrix spikes).

(3) This information may be obtained before well completion using formation testing tools, which can also record other parameters such as fluid density and fluid CO_2. Downhole conditions may alternatively be recorded after completion using wireline tools.

(h) Fracture pressure of the sequestration and confining layers:

(1) The GCS Project Operator must perform step rate tests for each CO_2 injection well that is part of the GCS project, and use the results of each test to determine the fracture pressure of the sequestration and confining layers.

(A) The GCS Project Operator must report the results of all step rate tests for each CO_2 injection well. Such data must be used to determine the maximum allowable injection pressure for the GCS project such that injection will not initiate or propagate faults of fractures in the sequestration or confining layer; and

(B) Step rate tests must meet the following requirements: (1) real time downhole pressure recording must be employed, (2) bottomhole pressure must be recorded at a zero injection rate for at least one full time step before the first step of the step rate test, and before one full time step after the last step of the step rate test, and (3) step rate test data reported under **Section 1.1.2** must be raw and unaltered, and include the injection rate, bottomhole pressure, surface pressure, pump rate volume, and time recorded continuously at a rate of every one second during the step rate test.

(2) The GCS Project Operator must also discuss how the calculated fracture pressure compares with data from core tests or other wells in the area; and

(i) Hydrogeologic testing:

(1) Upon completion of the injection well, prior to operation, the GCS Project Operator must conduct the following tests to verify hydrogeologic characteristics of the sequestration zone:

(A) A pressure fall-off test; and

(B) A pump test; or

(C) Injectivity tests.

(2) These tests must be designed to determine the injectivity of the sequestration zone to set operating limits for CO_2 injection rates and volumes; and

(3) Pressure fall-off tests must be conducted to verify hydrogeologic parameters, including but not limited to, the transmissibility of the sequestration zone, the static sequestration zone pressure, the skin factor, and to identify faults or fractures adjacent to the wellbore.

(j) The GCS Project Operator must determine or calculate additional physical and chemical characteristics of the sequestration and confining layers to augment other information gathered during the site characterization process, support the development of the AOR delineation model, or support setting of permit conditions (e.g., operational limits).

(k) The GCS Project Operator must provide the Executive Officer with the opportunity to witness all logging and testing in this subsection. The GCS Project Operator must submit a schedule of such activities to the Executive Officer 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.

(l) The GCS Project Operator must submit a descriptive report prepared that includes an interpretation of the results of the formation testing and well logging program with the application for injection approval. At a minimum, the report must include:

(1) The results of each test, log, and any supplemental data;

(2) An interpretation of the tests and logs, including any assumptions, and the determination of the sequestration and confining layer characteristics, including porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations;

(3) Any changes in interpretation of site stratigraphy based on formation testing and well logs; and

(4) A description of any alternative methods used that provide equivalent or better information, and that are required by, and approved of, the Executive Officer.

(5) The GCS Project Operator must demonstrate that the information collected is consistent with other available site characterization data submitted with the Permanence Certification and that the data support other assessments of stratigraphy and formation properties. The Executive Officer may compare the results of formation testing logs from different wells in the vicinity to interpret local stratigraphy, and verify the depths and properties of the proposed sequestration and confining layers.

2.4. Area of Review Delineation and Corrective Action

(a) The AOR and corrective action requirements are to ensure that the areas potentially impacted by a proposed GSC project are delineated, all wells that need corrective action receive it, and that this process is updated throughout the active life of the GCS project. The general relationship between site characterization, modeling, and monitoring activities at a GCS project is shown on **Figure 4**.

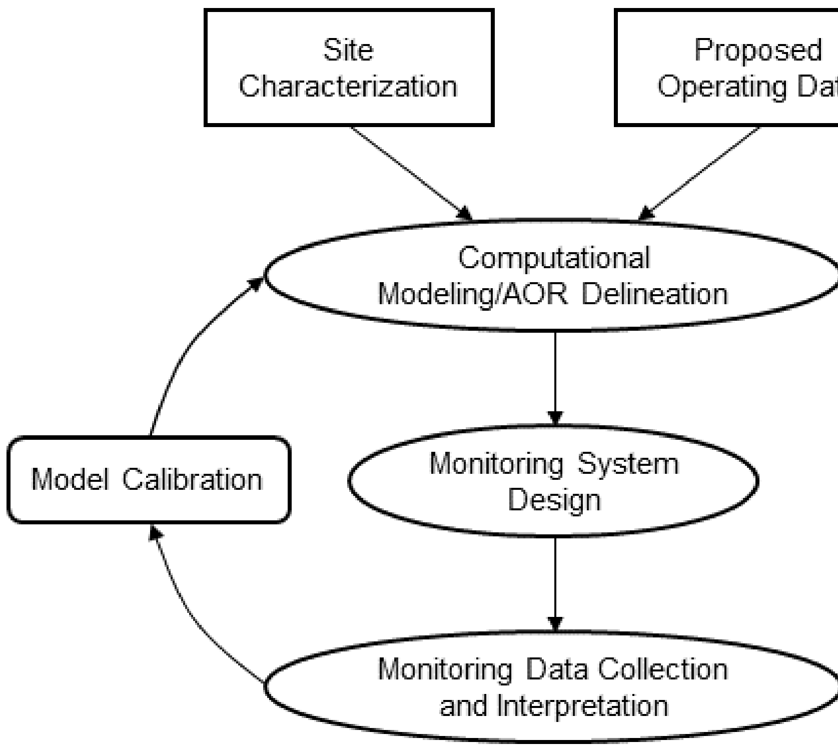

Figure 4. Flow chart of monitoring and modeling for a GSC project design.

(b) The basic requirements of the AOR delineation effort and corrective action requirements are as follows:

(1) The GCS Project Operator must prepare, maintain, and comply with a plan to delineate the AOR for a proposed GCS project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to CARB, which includes the following:

(A) Delineate the AOR using computational modeling as discussed in **Section 2.4.1**, based on available site characterization, monitoring, and operational data;

(B) Identify all wells within the AOR that penetrate the primary confining and sequestration zone and that require corrective action pursuant to **Sections 2.4** and ***2.4.3.1***;

(C) Perform corrective action on wells in the AOR that are deemed to require corrective action following **Section 2.4**;

(D) Reevaluate the AOR throughout the life of the GCS project following **Section 2.4.4**;

(E) Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AOR; and

(F) Retain all modeling inputs and data used to support initial AOR delineations and AOR reevaluations for the life of the GCS project and 10 years following site closure.

(2) AOR and Corrective Action Plan:

(A) As a part of the application for site approval, the GCS Project Operator must submit an AOR and Corrective Action Plan that includes the following information:

(B) The method for delineating the AOR that meets the requirements of **subsection 2.4(a)**, including the model used, assumptions made, and site characterization data on which the model will be based; and

(C) A description of:

1. The minimum fixed frequency, not to exceed five years, at which the GCS Project Operator will reevaluate the AOR and a justification for the proposed reevaluation frequency;

2. How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an AOR reevaluation; and

3. How corrective action will be conducted to meet the requirements of **Section 2.4**, including what corrective action will be performed prior to injection, how corrective action will be adjusted if there are any changes in the AOR, and how site access will be guaranteed for future corrective action.

2.4.1. Computational Modeling Requirements

(a) The GCS Project Operator must delineate the AOR using a computational model that accounts for the physical and chemical properties and site characteristics of the sequestration zone and injected CO_2 stream over the proposed life of the GCS project via the following actions:

(1) The computational model of the AOR must incorporate various parameters including site characterization, monitoring, operational data, and:

(A) Predict the lateral and vertical migration of the free-phase CO_2 plume and pressure front, as well as the dissolved CO_2 plume and formation fluids in the subsurface, from either (1) the commencement of injection activities until plume movement ceases, or (2) until pressure differentials sufficient to cause movement of injection or formation fluids from the sequestration zone into the subsurface;

(B) Be designed to simulate multiphase flow of several fluids (groundwater, CO_2, and hydrocarbons, if present), phase changes of CO_2, heat flow, significant pressure changes, and any other pertinent processes in geologic media based on scientific principles and accepted mathematical and governing equations;

(C) Be based on detailed geologic, hydrogeologic, and geomechanical data collected for the characterization of the sequestration and confining layers, including:

(1) Regional and site-specific geology, such as stratigraphy, formation lithology, elevation, thickness, structural geology (including faults, folding, fractures), and groundwater flow patterns;

(2) Pre-injection reservoir conditions including (1) hydrogeologic conditions such as intrinsic and relative permeabilities, porosity, capillary pressure, formation compressibility, water saturation, CO_2 saturation, and storativity, (2) reservoir fluid properties such as brine or hydrocarbon viscosity, density, temperature, pressure, composition or salinity, and compressibility, and (3) reservoir fluid chemical parameters including the aqueous diffusion coefficient and the aqueous or CO_2 solubility of particular chemicals;

(3) Pre-injection geomechanical information on fracture pressure and gradient in the sequestration and confining layers, as well as any geomechanical processes or models that are incorporated into the AOR delineation effort based on initial site characterization efforts;

(4) Existing or proposed operational and monitoring data, including fluid injection and withdrawal rates, injection bottom hole pressure, groundwater characterization and monitoring systems (as recorded in, for example, verification wells), CO_2 saturations and expected total volumes, the location and number of injection, production, and monitoring wells, and well construction details (total depth, perforated intervals, etc.);

(5) Initial model parameters such as: (1) initial conditions (e.g., fluid pressures and flow rates, etc.) within the domain at the beginning of the model run, and (2) boundary conditions (i.e., the description of the conditions of the system) at the edges of the model domain and at the location of injection and/or extraction wells; and

(6) Any other models, model parameters, and/or general assumptions that are incorporated or considered for the GCS project and AOR delineation based site-specific conditions. For example, mineral precipitation kinematic parameters may be introduced into a reactive transport model of the reservoir if the planned injectate and composition of water at depth are predicted, based on sampling and monitoring data, to react such that mineral precipitation may modify the permeability of the reservoir;

(D) Parameter values must be based on site data to the best extent possible. In cases where certain detailed site geologic characterization data are unavailable, parameter values may be estimated from standard values or relationships in the scientific literature. GCS Project Operators must indicate the range of values possible for their site and conditions, and must provide a justification for using each particular parameter value not directly measured in the field or the laboratory;

(E) All data collected to comply with site characterization requirements must be considered in the AOR delineation. Any additional data available in the vicinity of the site that may affect the AOR delineation, e.g., from the U.S. Geological Survey or other wells drilled within the vicinity of the AOR must also be included in model development;

(F) Utilize appropriate equations of state and constitutive relationships derived from equilibrium phase relationships and empirically based approximations, respectively;

(G) Explicitly state model orientation and gridding parameters, including the spatial temporal domains, grid spacing and gridding routine, coordinate system, horizontal datum, and the physical properties and assumptions used to define the domain boundaries;

(H) Describe and justify the method and assumptions used to estimate the value of the pressure front;

(I) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions;

(J) Consider potential migration through faults, fractures, and artificial penetrations; and

(K) The model must include, at a minimum:

(1) The sequestration zone, confining layer, dissipation interval, and secondary confining layer, with sufficient vertical resolution to account for buoyant plume migration; and

(2) A sufficient section of the primary confining layer to demonstrate that no leakage is expected to occur through the confining layer.

(3) The Executive Officer may require that additional zones be included in the computational model.

(2) The computer code utilized in an AOR delineation model should be publically or commercially available to CARB and GCS Project Operators and, preferably, be reported in peer-reviewed GCS literature:

(A) The code used for modeling the AOR must, at a minimum, consider multiphase flow of CO_2 in supercritical, liquid, and gaseous phases, including miscible and immiscible displacement, CO_2 dissolution in groundwater, density-driven flow, and the impact of injection on groundwater flow patterns;

(B) Codes may also be further modified to allow for complex three-dimensional heterogeneous formations; residual phase trapping; characteristic-curve hysteresis; mineral precipitation/dissolution reactions and subsequent mineral phase trapping or leaching of heavy metals; and leakage through faults, fractures, and abandoned wellbores; and

(C) If using a non-peer-reviewed independently developed or untested code, the developer must verify the model's accuracy by modeling test cases found in the literature before submitting the application for site approval.

2.4.2. AOR Delineation using Computational Modeling Results

(a) The initial site AOR delineation model must be submitted with the proposed AOR and Corrective Action Plan in the application for site approval pursuant to **Section 1.1.2**. The modeled AOR will be finalized after all site data are collected and pre-injection testing is complete;

(b) The AOR boundaries must be based on simulated predictions of the lateral extent of the separate-free-phase plume and pressure front for the cumulative GCS project model and must account for the anticipated injection rates from all planned injection wells;

(c) Each injection well within the AOR requires a separate injection approval from CARB; however, a single AOR modeling exercise may be conducted for all wells within a single GCS project at the discretion of the Executive Officer;

(d) The application for site approval submittal must include the following in support of the AOR delineation:

(1) Attributes of the code used to create the computational model, including the code name, name of the developing organization, and full accounting of or reference to the model governing equations, scientific basis, and any simplifying assumptions;

(2) A description of the model domain, such as the model's lateral and vertical extents, geologic layer thickness, and grid cell sizes, as presented on maps and cross-sections;

(3) An accounting of all equations of state used for all modeled fluids (groundwater, CO_2);

(4) Any constitutive relationships, such as relative-permeability saturation relationships, and how they were determined;

(5) Values of all model parameters throughout the entire model domain, as a function of time if necessary, including initial conditions and boundary conditions, and a description of how model parameters were determined based on graphical/map formats;

(6) Raw model input and output files; and

(7) Model results, including predictions of the CO_2 free-phase plume and pressure-front migration over the lifetime of the GCS project. Model results must be presented in contour maps, cross sections, and/or graphs showing plume and pressure front migration as a function of time, and that the application for site approval submittal must include the outcome of parameter sensitivity analysis and model calibration.

2.4.3. Corrective Action Requirements

(a) Corrective Action Plan:

(1) The GCS Project Operator is required to submit a Corrective Action Plan with the initial application for site approval pursuant to **Sections 1.1.2** and **subsection 2.4.3(a)**. The AOR and Corrective Action Plan must describe:

(2) Methods for the identification of all artificial penetrations within the AOR;

(3) Proposed corrective action for unplugged or improperly or insufficiently plugged wells penetrating the primary confining layer or uppermost sequestration zone within the AOR; and

(4) The schedule of corrective action activities that minimizes risk to public health and the environment.

(b) Following Executive Officer approval and pursuant to the AOR and Corrective Action Plan, GCS Project Operators of CO_2 injection wells must perform the following actions:

(1) Identify all artificial penetrations, including all wells within the AOR, and provide a tabulation of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Executive Officer may require;

(2) Identify all wells within the AOR that penetrate the primary confining layer and/or sequestration zone within the AOR and provide casing diagrams for those wells pursuant to **Section *2.4.3.1***;

(3) Determine which abandoned wells in the AOR have been plugged and cemented across all perforations and extending at least 100 feet above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, the intended sequestration zone, or the oil and gas zone; and

(4) Use a variety of methods to identify all wells within the AOR that require corrective action, such as those that are improperly plugged or abandoned such that they may leak gas or fluid, or those that are currently leaking gas or fluids, including, but not limited to:

(A) Historical research of state and local databases, county records, and private data;

(B) Site reconnaissance, including interviewing local residents and property owners, as well as conducting a physical search for features indicative of abandoned wells;

(C) Aerial and satellite imagery review;

(D) Geophysical methods including magnetic, ground penetrating radar, and electromagnetic surveys;

(E) Abandoned well plugging records; and

(F) Well field testing, such as the analysis of each well using CH_4 detection equipment.

(c) GCS Project Operators must perform corrective action on all wells within the AOR that are determined to need corrective action, including all wells that penetrate the primary confining layer and/or sequestration zone and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement into the subsurface that is likely to reach the atmosphere, prior to the commencement of injection. **Figure 5** presents a flow chart that illustrates how the various evaluation tools must be used together to evaluate abandoned wells. GCS Project Operators must submit a descriptive report with the application for injection approval that demonstrates how corrective action was applied to deficient wells.

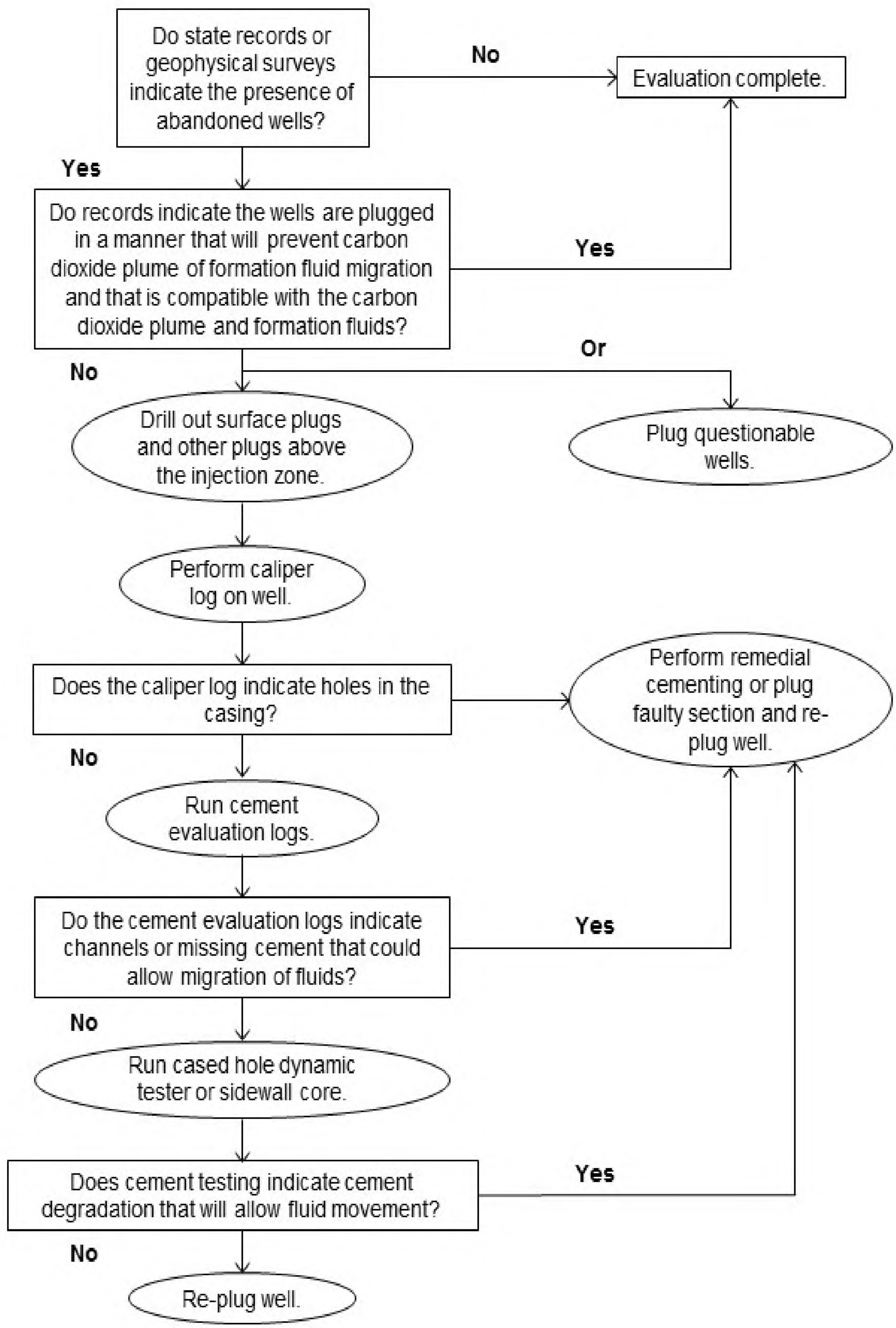

Figure 5. Well evaluation flow chart.

(d) Prior to injection approval, GCS Project Operators must perform corrective action on all wells within the delineated AOR that require corrective action. In performing corrective action, GCS Project Operators must use methods designed to prevent the movement of fluid out of the sequestration zone and into the subsurface, including use of materials compatible with the CO_2 stream, where appropriate.

(1) A well requires plugging if:

(A) Records indicate that a well plug sufficient to prevent upward movement of fluids does not exist at a depth corresponding to the primary confining layer, or there are no well plugs below permeable formations that may exhibit cross flow of mobilized fluids along the wellbore or casing; and/or

(B) Field evaluations reveal cracks, channels, or annuli in the plug that would allow fluid migration or suggest the plug material may corrode in response to reactions with CO_2; and/or

(C) Field tests indicate the well is leaking gas and/or fluids.

(2) A well requires remedial cementing if records or field evaluations indicate that the cement surrounding the wellbore has failed or has cracks, channels, or annuli that could allow migration of CO_2, or if the well has not been cemented.

(3) Materials used for cementing of abandoned wells must be supplemented with or replaced by materials such as polymer gels and acrylic grouts, if required by the Executive Officer.

(e) If corrective action is warranted during the injection or post-injection period based on AOR reevaluation **Section 2.4.4**, the GCS Project Operator is required to take the following actions:

(1) Identify all wells or features within the AOR that require corrective action;

(2) Identify the appropriate corrective action the well or feature requires pursuant to **Section 2.4.3**;

(3) Prioritize corrective actions to be performed; and

(4) Conduct corrective actions under a schedule that minimizes risk to public health and the environment.

2.4.3.1. Casing Diagrams of Wells Penetrating the Primary Confining layer

(a) Casing diagrams submitted under **Section *2.4.3.1*** must demonstrate that the wells will not be potential conduits for fluid migration outside of the sequestration zone or otherwise have any adverse effects on the GCS project or cause damage to public health or the environment, and must meet the following requirements:

(1) Casing diagrams must include the following data (to the extent known):

(A) Operator name, lease name, well number and API number of the well;

(B) Ground elevation from sea level;

(C) Reference elevation (i.e. rig floor or Kelly bushing);

(D) Base of freshwater;

(E) Sizes, grades, connection type, and weights of casing and tubing;

(F) Depths of casing shoes, stubs, and liner tops;

(G) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, casing damage, and type and extent of any debris left in well, and any other feature that influences flow in the well or may compromise the mechanical integrity of the well;

(H) Information regarding associated equipment such as subsurface safety valves, packers, and gas lift mandrels;

(I) Diameter and measured and true vertical depth of wellbore;

(J) Wellbore path that includes inclination and azimuth measurements;

(K) Cement plugs inside casings, including top and bottom of cement plug, with measuring method indicated;

(L) Cement fill behind casings, including top and bottom of cement fill, with measuring method indicated;

(M) Type and density of fluid between cement plugs;

(N) Depths and names of the formations, zones, and sand markers penetrated by the well, including the top and bottom of the zone where injection will occur;

(O) All steps of cement yield and cement calculations performed;

(P) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job completed in each well; and

(Q) When multiple boreholes are drilled, all of the information listed in this section for the original hole and for any subsequent redrilled or sidetracked wellbores.

(2) Casing diagrams must be submitted as both a graphical diagram and as a flat file data set.

(3) Any additional information that the Executive Officer may require.

2.4.4. AOR Reevaluation

(a) Every five years, or when monitoring and operational conditions warrant pursuant to **Section *2.4.4.1***, GCS Project Operators must:

(1) Reevaluate the AOR in the manner specified in **Sections 2.4.2**, **2.4.1**, and **2.4.2**;

(2) Identify all wells in the reevaluated AOR that require corrective action in the same manner specified in **Sections 2.4.2** and ***2.4.3.1*(d)**;

(3) Perform corrective action on wells requiring corrective action in the reevaluated AOR in the same manner specified in **Sections 2.4.2** and ***2.4.3.1*(e)** and **(f)**; and

(4) Either submit an amended AOR and Corrective Action Plan, or demonstrate to the Executive Officer through monitoring data and modeling results that no amendments to the AOR and Corrective Action Plan are needed. Any amendments to the AOR and Corrective Action Plan, or demonstrations of no changes to the AOR and Corrective Action Plan, must be approved by the Executive Officer and must be incorporated into the Permanence Certification.

(b) The Emergency and Remedial Response Plan, Post-Injection Site Care and Closure Plan, and the demonstration of financial responsibility in **Section 7** must account for the AOR delineated as specified in **Section 2.4.2** most recently evaluated AOR delineated under **subsection 2.4.2(a)**;

(c) AOR Reevaluation Requirements:

(1) Using newly collected and existing data, the GCS Project Operators must update and verify the site model and reevaluate the size and shape of the AOR as specified in the AOR and Corrective Action Plan. GCS Project Operators are required to take the following steps to evaluate GCS project data and, if necessary, reevaluate the AOR:

  (1) Review monitoring data and compare it to the computational model predictions to assess whether the predicted CO_2 plume migration is consistent with actual data;

  (2) Review operating data to verify that it is consistent with the inputs used in the most recent modeling effort; and

  (3) Review any new geologic data acquired since the last modeling effort and identify if any new data materially differ from modeling efforts.

(2) If the information reviewed is consistent with, or unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of free-phase plume and pressure front movement, the GCS Project Operator must prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AOR is needed. The report must include the data and results demonstrating that no changes are necessary;

(3) If material changes have occurred such that the actual CO_2 free-phase plume or pressure front may extend beyond the area originally modeled, the GCS Project Operator must reevaluate the AOR, and the following steps must be taken:

  (1) Revision of the site conceptual model based on new site characterization, operational, or monitoring data;

  (2) Recalibration of the model to minimize the differences between monitoring data and model simulations; and

  (3) Re-delineate the AOR as described in **Section 2.4.1** and **subsection 2.4**.

(4) Review wells in any newly identified areas of the AOR and apply corrective action to deficient wells pursuant to **Section 2.4.4**.

(5) Following each evaluation, the GCS Project Operator must prepare and submit a report documenting the reevaluation process, including a description of the updated modeling effort, the data used for the reevaluation, any corrective actions needed, and the schedule for any corrective actions to be performed.

(6) Update the AOR and Corrective Action Plan to reflect the revised AOR, along with other related GCS project plans, as needed, and submit for approval by the Executive Officer.

(d) AOR Reevaluation Cycle:

(1) The GCS Project Operator must reevaluate the AOR at the minimum fixed frequency, not to exceed five years, as specified in the AOR and Corrective Action Plan, or when monitoring and operational conditions warrant, following **subsection 2.4.4(a)**;

(2) AOR reevaluations must be performed periodically during the post-injection phase following the Post-Injection Site Care and Site Closure Plan at **Section 5.2**. Post-injection pressure monitoring data must be compared to model pressure conditions predicted for the post-injection site care timeframe;

(3) If monitoring or operational data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume and/or pressure front is occurring, or there are deviations from modeled predictions such that the actual plume or pressure front may extend vertically or horizontally beyond that modeled, the GCS Project Operator must initiate an AOR reevaluation prior to the next scheduled reevaluation pursuant to **subsection 2.4.4(f)**.

2.4.4.1. Triggers for AOR Reevaluations Prior to the Next Scheduled Reevaluation

(e) Unscheduled reevaluations of the AOR must be based on quantitative changes of the monitoring parameters in each well of the GCS project. These changes include:

(1) Changes in pressure that are unexpected and outside three standard deviations[7] from the average;

(2) Changes in temperature that are unexpected and outside three standard deviations from the average;

(3) Increases in CO_2 saturation that indicate the movement of CO_2 into or above the confining layer, unless the changes are found to be related to well integrity;

(4) Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brine into or above the confining layer, unless the changes are found to be related to well integrity;

[7] NEEDS REFERENCE

(5) Pressure in the GCS injection wells exceeds 90 percent of the geologic formation fracture pressure at the point of measurement;

(6) A failure of an mechanical integrity test in a GCS injection well or a monitoring well that indicates a loss of mechanical integrity at the well or wells; and

(7) Seismic monitoring data that indicates the presence of a fault or fracture in or near the confining layer or a fault or fracture within the sequestration zone that indicates propagation into the confining layer.

(f) An unscheduled AOR reevaluation may also be needed if it is likely that the actual free-phase plume or pressure front CO_2 extend beyond that modeled front because any of the following has occurred:

(1) An earthquake of magnitude 2.7[8] or greater within a one mile radius of the GCS project; or

(2) New site characterization data change the computational model to such an extent that the predicted free-phase plume or pressure front extends vertically or horizontally beyond the predicted AOR.

(g) Any site-specific criteria that will trigger an AOR reevaluation for a particular GCS project must be included in the AOR and Corrective Action Plan.

2.5. Baseline Surface and Near-Surface Monitoring

(a) As part of the testing required to meet certification, **Section 4.1**, GCS Project Operators must monitor the surface and near-surface for CO_2 leakage that may endanger public health and the environment. The GCS Project Operator must submit a Baseline Surface and Near-Surface Testing Plan with the application for site approval.

(b) The monitoring frequency and spatial distribution of surface and near-surface monitoring must be decided using baseline data according to a timeline set forth in the application for site approval of no less than one year prior to the initiation of injection, or as required by the Executive Officer.

(c) Baseline data on CO_2 concentrations and fluxes collected prior to operation must be used for comparison to levels during and after the operational phase of the GCS project to detect any CO_2 leakage to the shallow subsurface and surface or atmosphere.

(d) Any properties of the AOR that may affect baseline data must be evaluated, including but not limited to: soil type, soil organic carbon content, vegetation type and density, topography, and surface water hydrology.

[8] NEEDS REFERENCE

(e) Data collection and analyses:

(1) The determination of the baseline spatial distribution of soil CO_2 fluxes and concentrations must be determined on a site-specific basis, but requires, at a minimum, repeat measurements at several fixed sites, and over a period of one year, to capture any seasonal or diurnal variations. GCS Project Operators must plan the location of soil gas and surface air sampling points based on the following considerations:

(A) Avoid areas with highly fluctuating background concentrations, based on previously recorded data;

(B) Target potential point-sources, including wellheads, artificial penetrations, and fault or fracture zones. A transect-profiling approach may be used for linear features, such as faults;[9] and

(C) A grid methodology,[9] must be used when monitoring soil for non-point source leakage throughout the AOR. Grid cell spacing may range over several orders of magnitude, depending on site-specific factors.

(f) Baseline surface and near-surface monitoring report:

(1) The GCS Project Operator must submit a descriptive report of baseline monitoring data and interpretations with the application for injection approval. The report must include surface air or soil gas analyses, and GCS Project Operators must submit, at a minimum, the following:

(A) Site characteristics: soil type, soil organic carbon content, vegetation type and density, topography, surface water hydrology;

(B) Sampling locations (in map form) and dates sampled;

(C) Soil temperature and moisture data;

(D) Atmospheric conditions;

(E) Sampling and analytical methods, including detection limits;

(F) Results presented as concentrations and fluxes in tabular and graphic form, including quality assurance (QA) samples and analyses;

(G) Methods and results of regression analyses; and

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[9] ASTM International (ASTM), "Standard Guide for Soil and Gas Monitoring in the Vadose Zone," ASTM D5314 - 092 (2006), DOI: 10.1520/D5314-92R06. http://www.astm.org.

(H) Methods and results of any ecological modeling performed, including input data, outputs, and sensitivity analyses.

(g) The GCS Project Operator must demonstrate that the locations sampled represent a reasonable grid size and that potential point sources are represented and will serve as a good baseline to compare to future monitoring data. The GCS Project Operator must also demonstrate that seasonal and diurnal variations in CO_2 levels have been captured and describe the variability in the data for future reference. If an inadequate time series of analyses was performed or if there are concerns regarding the quality of analytical data, the GCS Project Operator may need to collect and submit additional data.

3. Injection Well Construction and Operating Requirements

3.1. Injection Well Construction

(a) General Requirements:

(1) The GCS Project Operator must ensure that all GCS injection wells are constructed and completed to:

(A) Prevent the movement of fluids into or between any unauthorized zones;

(B) Permit the use of appropriate testing devices and workover tools; and

(C) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.

(b) Casing and cementing of GCS injection wells:

(1) Casing and cement or other materials used in the construction of each certified GCS injection well must have sufficient structural strength and be designed for the life of the GCS project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the API, ASTM International, or comparable standards acceptable to the Executive Officer. The casing and cementing program must be designed to prevent the movement of fluids out of the sequestration zone and into the subsurface that is likely to reach the atmosphere. In order to allow the Executive Officer to determine and specify casing and cementing requirements, the GCS Project Operator must provide the following information:

(A) Depth to the sequestration zone;

(B) Injection pressure, external pressure, internal pressure, and axial loading;

(C) Hole size;

(D) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);

(E) Corrosiveness of the CO_2 stream and formation fluids;

(F) Downhole temperatures;

(G) Lithology of sequestration and confining layer;

(H) Type or grade of cement and cement additives; and

(I) Quantity, chemical composition, and temperature of the CO_2 stream.

(2) Surface casing must extend through the base of the lowermost freshwater aquifer and be cemented to the surface through the use of a single or multiple strings of casing and cement.

(3) At least one long string casing, using a sufficient number of centralizers, must extend to the sequestration zone and must be cemented by circulating cement to the surface in one or more stages.

(4) Cement and cement additives must be of sufficient quality and quantity to maintain integrity over the design-life of the GCS project. The integrity and location of the cement must be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure the likelihood of an unintended release of CO_2 from the sequestration zone into the subsurface that is likely to reach the atmosphere is minimal.

(5) Cement and cement additives must be compatible with the CO_2 stream and formation fluids within the sequestration zone.

(6) Any changes to casing and/or cement materials or designs that deviate from the casing and cementing program in the initial GCS project application for injection approval must be submitted and approved by the Executive Officer before installation.

(c) Tubing and packer:

(1) Tubing and packer materials used in the construction of each GCS injection well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by API, ASTM International, or comparable standards acceptable to the Executive Officer.

(2) GCS Project Operators of GCS injection wells must inject fluids through tubing with a packer set within the long string casing at a point within or below the primary confining layer immediately above the sequestration zone, or at an interval at a location approved by the Executive Officer.

(3) In order for the Executive Officer to determine and specify requirements for tubing and packer, the GCS Project Operator must submit the following information:

(A) Depth of setting;

(B) Characteristics of the CO_2 stream (chemical content, corrosiveness, temperature, and density) and formation fluids;

(C) Maximum proposed injection pressure;

(D) Maximum proposed annular pressure;

(E) Proposed injection rate (intermittent or continuous) and volume and/or mass of the CO_2 stream;

(F) Size of tubing and casing; and

(G) Tubing tensile, burst, and collapse strengths.

(4) Any change to the tubing and packer used in the well that deviates from those proposed in initial GCS project application for injection approval must be submitted and approved by the Executive Officer before installation.

(d) Wellheads and Valves:

(1) The GCS Project Operator must equip GCS injection wells with wellheads, valves, piping, and facilities that meet or exceed design standards developed for such materials by API, ASTM International, or comparable standards acceptable to the Executive Officer.

(2) All injection piping, valves, and facilities must meet or exceed design standards for the maximum anticipated allowable injection pressure, and must be maintained in a safe and leak-free condition.

(3) The GCS Project Operator must equip all ports on the wellhead assembly above the casing bowl of injection wells with valves, blind flanges, or similar equipment.

(4) The GCS Project Operator must equip wells with valves to provide isolation of the wells from the pipeline system and to allow for entry into the wells.

(e) Routine well maintenance:

(1) Routine well maintenance must be conducted at a minimum of every six months. Routine maintenance consists of wellhead valves maintenance and measurement of all casings annular pressures. If a deviation is observed, the appropriate remediation plan must be triggered.

3.2. Pre-Injection Testing

(a) During the drilling and construction of well for the GCS project, the GCS Project Operator must run appropriate logs, surveys, and tests to: (1) determine or verify the depth, thickness, porosity, permeability, and lithology of the sequestration zone, (2) measure the salinity and TDS of any formation fluids in all relevant geologic formations, (3) ensure conformance with the injection well construction requirements under **Section 3.1,** and (4) establish accurate baseline data against which future measurements will be compared. The GCS Project Operator must submit, with the application for injection approval, a descriptive report that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:

(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole that is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and

(2) A series of tests before and upon installation of the surface casing:

(A) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented; and

(B) Tests to evaluate the hydrological characteristics of the wellbore pursuant to **Section 2.3.1**.

(3) A series of tests before and upon installation of the long string casing:

(A) A cement bond and variable density log, and a temperature log after the casing is set and cemented; and

(B) A series of tests to evaluate the geological and hydrological characteristics of the wellbore following procedures outlined in **Section 2.3.1**.

(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which must include:

(A) A pressure test with liquid or gas;

(B) A tracer survey such as oxygen-activation logging;

(C) A temperature or noise log; and

(D) A casing inspection log.

(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved by the Executive Officer.

(b) The GCS Project Operator must take core samples of the sequestration and confining layers and representative formation fluid samples from the sequestration zone, and must submit to the Executive Officer a detailed report following procedures in **subsection 2.3.1(e)**.

(c) The GCS Project Operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the sequestration zone.

(d) At a minimum, the GCS Project Operator must determine or calculate the following information concerning the sequestration and confining layers pursuant to **subsection 2.3(e)(3)(A)**:

(1) Fracture pressure;

(2) Other physical and chemical characteristics of the sequestration and confining layers; and

(3) Physical and chemical characteristics of the formation fluids in the sequestration zone.

(e) Upon completion, but prior to operation, the GCS Project Operator must conduct tests to verify hydrogeologic characteristics of the sequestration zone pursuant to **subsection 2.3(e)(3)(A)**, including a pressure fall-off test and a pump test or injectivity tests.

(f) The GCS Project Operator must provide the Executive Officer with the opportunity to witness all logging and testing by this **Section 3.2**. The GCS Project Operator must submit a schedule of such activities to the Executive Officer 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.

3.3. Injection Well Operating Requirements

(a) The GCS Project Operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures in the sequestration zone. In no case may injection pressure initiate fractures in the confining layer, or cause movement of the injection or formation fluids out of authorized zones.

(b) Injection between the outermost casing and the wellbore is prohibited. The space between the casing and the formation is to be cemented following **subsection 3.1(b)(3)**.

(c) No injectate other than CO_2 must be injected except fluids used for well workovers and tests.

(d) The GCS Project Operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid (e.g., a brine containing a corrosion inhibitor).

(e) Other than during periods of well workover approved by the Executive Officer in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the GCS Project Operator must maintain mechanical integrity in the GCS injection well(s) at all times.

(f) If a shutdown (either downhole or at the surface) is triggered or a loss of mechanical integrity is discovered, the GCS Project Operator must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under **subsection 3.3(e)** of this section otherwise indicates that the well may be lacking mechanical integrity, the GCS Project Operator must:

  (1) Immediately cease injection, otherwise, all credits generated are subject to invalidation;

  (2) Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone;

  (3) Notify the Executive Officer in writing within 24 hours;

  (4) Restore and demonstrate mechanical integrity prior to resuming injection; and

  (5) Notify the Executive Officer when injection can be expected to resume.

3.4. Operating Restrictions and Incident Response

(a) In order to receive any credit, the GCS Project Operator must cease injection into the affected injection well and must not resume injection into the well without subsequent approval from the Executive Officer if any of the following occur:

(1) The GCS Project Operator has not performed mechanical integrity testing on the well as required by **Section 4.2** or the notification and results required under **Section 4.2.2** have not been provided to the Executive Officer;

(2) The well failed a mechanical integrity test required by **Section 4.2** or there is any other indication that the well lacks mechanical integrity or is otherwise incapable of performing as approved by the Executive Officer;

(3) An automatic alarm or automatic shut-off system is triggered;

(4) The well experiences a significant, unexpected change in the annulus or injection pressure;

(5) There is any indication of a failure, breach, or hole in the well tubing, packer or well casing, including failures above or below a packer;

(6) There is any indication that fluids being injected into the well are not confined to the intended zone of sequestration;

(7) There is any indication that damage to public health, the environment, natural resources, or loss of hydrocarbons is occurring by reason of the injection; or

(8) Any non-compliance with any certification condition or local regulatory requirement is discovered and the Executive Officer determines that the injection must cease.

(b) The GCS Project Operator must immediately notify the Executive Officer upon ceasing injection operations by reason of **subsection 3.3.1(a)**, indicating the affected well and the specific reason for ceasing injection.

(c) The GCS Project Operator must comply with all operational and remedial directives of the Executive Officer related to the reason for ceasing injection.

4. Injection Monitoring Requirements

4.1. Testing and Monitoring

(a) Testing and Monitoring Plan. The GCS Project Operator must prepare, maintain, and comply with a testing and monitoring plan to ensure that the GCS project is operating as certified and that the CO_2 injected is permanently sequestered. The Testing and Monitoring Plan must be submitted with the application for site approval, and must include a description of how the GCS Project Operator will meet the testing and monitoring requirements, including accessing sites for all necessary monitoring and testing during the active life of the GCS project and the post-injection site care period. Testing and monitoring associated with GCS projects must include:

(1) Analysis of the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics pursuant to **Section 6.3.1.1**.

(2) Installation and use, except during well workovers, of continuous recording devices to monitor: (1) injection pressure, rate, and volume, (2) pressure on the annulus between the tubing and the long string casing, and (3) the annulus fluid volume added.

(3) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in **subsection 5.1(b)**, by:

(A) Analyzing corrosion coupons of the well construction materials placed in contact with the with the CO_2 stream; or

(B) Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop; or

(C) Using an alternative method approved by the Executive Officer.

(4) Periodic monitoring of groundwater quality and geochemistry above the confining layer.

(5) The location and number of monitoring wells based on specific information about the GCS project, including injection rate and volume, geology, the presence of artificial penetrations and other factors; and

(6) The monitoring frequency and spatial distribution of monitoring wells based on any modeling results required by **Section 4.4.1**.

(7) A demonstration of external mechanical integrity pursuant to **Section 6.2** at least once per year until the injection well is plugged, and, if required by the Executive Officer, a casing inspection log pursuant to requirements at **subsection 6.2(b)** at a frequency established in the Testing and Monitoring Plan.

(8) A pressure fall-off test at least once every five years, pursuant to **Section 6.3.1.6**, unless more frequent testing is required by the Executive Officer based on site-specific information.

(9) Testing and monitoring to track the extent of the dissolved and free-phase CO_2 plume, and the presence or absence of elevated pressure.

(10) Surface air monitoring and soil gas monitoring to detect potential movement of CO_2 in the shallow subsurface or atmosphere.

(11) At a minimum, the monitoring plan must stipulate and include:

(A) The frequency of data acquisition;

(B) A record keeping plan;

(C) The frequency of instrument calibration activities;

(D) The QA/QC provisions on data acquisition, management, and record keeping that ensures it is carried out consistently and with precision;

(E) The role of individuals performing each specific monitoring activity; and

(F) Methods to measure and quantify the following data:

1. Quantity of CO_2 emitted from the capture site;

2. Quantity of CO_2 sold to third parties (e.g., for enhanced oil recovery) including sufficient measurements to support data required; and

3. Quantity of CO_2 injected into each well in the GCS project, metered at the wellhead.

(12) Any additional monitoring, as required by the Executive Officer, necessary to support, upgrade, and improve computational modeling of the AOR evaluation required under **Section 4.4.1**; and

(13) The GCS Project Operator must periodically review the Testing and Monitoring Plan to incorporate monitoring data collected under this subsection, operational data collected under **Section 5**, and the most recent AOR reevaluation performed under **Section 4.4.5**. In no case must the GCS Project Operator review the Testing and Monitoring Plan no less than once every five years. Based on this review, the GCS Project Operator must submit an amended Testing and Monitoring Plan or demonstrate to the Executive Officer that no amendment to the Testing and Monitoring Plan is

needed. Any amendments to the Testing and Monitoring Plan must be approved by the Executive Officer. Amended plans or demonstrations must be submitted to the Executive Officer as follows:

(A) Within one year of an AOR reevaluation;

(B) When required by the Executive Officer.

4.2. Mechanical Integrity Testing

(a) Mechanical integrity testing provides information about the condition of the well, and enables the determination of any leaks in the tubing, casing, or packer, or fluid flow behind the casing.

(b) Other than during periods of well workover in which the annulus between the tubing and the long-string casing is disassembled for maintenance or corrective procedures, a GCS injection well must have and maintain mechanical integrity. A GCS injection well has mechanical integrity if:

(1) There is no internal leak in the casing, tubing, or packer;

(2) There is no significant external fluid movement out of the injection zone through channels adjacent to the injection wellbore; and

(3) Corrosion monitoring, pursuant to **Section 6.3.1.4**, reveals no loss of mass or thickness that may indicate the deterioration of well components (casing, tubing, or packer).

(c) The GCS Project Operator must conduct a mechanical integrity test and casing inspection log as follows:

(1) Internal and external mechanical integrity must be demonstrated prior to injection, and the GCS Project Operator must submit a descriptive report of the test results with the application for injection approval.

(2) Within one year of the previous test, and at least once per year thereafter, the GCS Project Operator must perform the following testing to demonstrate internal mechanical integrity and to determine the absence of significant fluid movement under **subsection 6.2(b)(1)**:

(A) An annulus pressure or annulus monitoring test;

(B) A radioactive tracer test;

(C) A water-brine interface test;

(D) A pressure test with liquid or gas;

(E) A casing inspection log; or

(F) An alternative test approved by the Executive Officer pursuant to requirements at **subsection 6.2(d)**.

(3) Within one year of the previous test, and at least once per year thereafter, the GCS Project Operator must perform the following testing to demonstrate external mechanical integrity and to determine the absence of significant fluid movement under **subsection 6.2(b)(2)**:

(A) A temperature log;

(B) A noise log;

(C) An oxygen-activation log indicating lack of fluid migration behind the casing;

(D) A radioactive tracer survey indicating lack of fluid migration behind the casing;

(E) A cement bond log showing gamma ray, transit time, collar locator and variable density log; or

(F) An alternative test approved by the Executive Officer pursuant to requirements at **subsection 6.2(d)**.

(4) The well must pass a suitable pressure test to demonstrate mechanical integrity after any workover that has the potential to compromise the internal mechanical integrity of the well, including but not limited to the downhole replacement of tubing, safety valves, and/or electrical submersible pumps.

(5) Prior to plugging the well, the GCS Project Operator must demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of **Section 7.1**.

(6) The Executive Officer may allow the use of any other tests to demonstrate mechanical integrity other than those listed above pursuant to requirements at **subsection 6.2(d)**.

(d) Casing wall thickness must be inspected prior to injection, and at least once every 24 months thereafter, to determine if there are any possible issues with casing integrity. If the casing wall thickness inspection indicates that within the next 24 months thinning of the casing will diminish the casing's ability to contain the well's maximum allowable operating pressure, then the well must be remediated in accordance with the AOR and Corrective Action Plan at **Section 4.4.4** and must not be used for injection without subsequent approval by the Executive Officer. The GCS Project Operator must perform the following tests to demonstrate the casing well thickness:

(1) A magnetic flux test; or

(2) An ultrasonic test.

(e) The Executive Officer may require any other test deemed necessary to evaluate mechanical integrity under **subsections 6.2(b)(1)** or **(b)(2)**. Also, the Executive Officer may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of CARB. To obtain approval for a new mechanical integrity test, the GCS Project Operator must submit a written request to the Executive Officer setting forth the proposed test and all technical data supporting its use. The Executive Officer may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which it is proposed.

(f) To evaluate the absence of significant leaks under **subsection 6.2(b)(1)**, the GCS Project Operator must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes, pressure on the annulus between tubing and long-string casing, and annulus fluid volume as specified in **Section 6.3.1**;

(g) If required by the Executive Officer, at a frequency specified in the Testing and Monitoring Plan following **Section 6.1**, the GCS Project Operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.

(h) In conducting and evaluating the tests listed in this section or others to be allowed by the Executive Officer, the GCS Project Operator must apply methods and standards generally accepted in the industry. When the GCS Project Operator reports the results of mechanical integrity tests to the Executive Officer, he/she must include a description of the tests and the methods used. In making his/her evaluation, the Executive Officer must review monitoring and other test data submitted since the previous evaluation.

(i) The Executive Officer may require additional or alternative tests if the results presented by the GCS Project Operator under **subsections 6.2(b)** through **(f)** are not satisfactory to the Executive Officer to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid out of the sequestration zone that resulting from the injection activity as stated in **subsections 6.2(b)(1)** and **(2)**.

(j) The GCS Project Operator must demonstrate mechanical integrity at any time upon written notice from the Executive Officer.

(k) Prior notice and reporting.

(1) The GCS Project Operator must notify the Executive Officer of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Executive Officer, a shorter time period may be allowed.

(2) Reports of mechanical integrity demonstrations that include logs must include an interpretation of results by an experienced log analyst. The GCS Project Operator must report the results of a mechanical integrity demonstration within the time period specified in **Section 3.3.4**.

(l) Gauge and meter calibration: The GCS Project Operator must calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration must be noted on or near the gauge or meter. A copy of the calibration certificate must be submitted to the Executive Officer with the report of the test. Pressure gauge resolution must be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and must be identified in the procedure submitted to the Executive Officer prior to the test.

4.2.1. Reporting of Mechanical Integrity Tests

a) The GCS Project Operator must submit a descriptive report prepared by an experienced log analyst that includes the results of any mechanical integrity test with the application for injection approval, and annually, thereafter through the active life of the GCS Project. At a minimum, the report must include:

(1) Chart and tabular results of each log or test;

(2) The interpretation of log results provided by the log analyst;

(3) A description of all tests and methods used;

(4) The records and schematics of all instrumentation used for the tests and the most recent calibration of any instrumentation;

(5) The identification of any loss of mechanical integrity, evidence of fluid leakage, and remedial action taken;

(6) The date and time of each test;

(7) The name of the logging company and log analyst;

(8) For any tests conducted during injection, operating conditions during measurement, including injection rate, pressure, and temperature (for tests run during well shut-in, this information must be provided relevant to the period prior to shut-in); and

(9) For any tests conducted during shut-in, the date and time of the completion of injection and records of well stabilization.

4.2.2. Loss of Mechanical Integrity

(a) If the GCS Project Operator or the Executive Officer finds that a well (1) fails to demonstrate mechanical integrity during a test, (2) fails to maintain mechanical integrity during operation, or (3) that a loss of mechanical integrity is suspected during operation, the GCS Project Operator must:

(1) Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is evidence of substantial endangerment to public health or the environment from any fluid movement out of the intended sequestration zone, implement the Emergency and Remedial Response Plan, **Section 8**;

(2) Follow the reporting requirements as directed in **Sections 3.3.4** through **3.3.6**; and

(3) Restore and demonstrate mechanical integrity prior to resuming injection or plugging the well.

(b) If the well loses mechanical integrity prior to the next scheduled test date, then the well must be repaired and retested within 30 days of losing mechanical integrity.

(c) If the well lost mechanical integrity prior to the next scheduled test date, and it was repaired, the GCS Project Operator must submit a descriptive report documenting the type of failure, the cause, the required repairs, and a new test of mechanical integrity following the requirements of **Section 6.2.2** in the next quarterly report.

4.3. GCS Project Monitoring

(a) Monitoring requirements for GCS projects are addressed in two separate categories: GCS project emissions monitoring, and the monitoring, measurement, and verification of containment. The first includes quantification and measurement activities required to quantify the net GHG reductions from the

GCS project that are addressed in the Permanence Requirements. The second category is for monitoring, measurement, and verification activities that are required to ensure that the CO2 injected is permanently contained with the storage complex.

(b) The GCS Project Operator must install and use:

(1) Continuous recording devices to monitor: the injection pressure, the rate, volume and/or mass, and temperature of the CO_2 stream, and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and

(2) Alarms and automatic surface and downhole shut-off systems (e.g., automatic shut-off, check valves) for wells, or other mechanical devices that provide equivalent protection.

(c) The GCS Project Operator must retain all records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports, for emissions and containment monitoring for a period of 10 years after site closure.

4.3.1. GCS Project Emissions Monitoring

(a) Emissions monitoring requirements include measurements of relevant parameters to account for all supplemental energy inputs (e.g., fossil fuels and electricity) required for the operation of the GCS project. Data capture must be sufficient to ensure that the quantification and documentation of CO_2 sequestered is replicable and verifiable pursuant to the Accounting Requirements from **Part C**.

(b) GCS project monitoring techniques must use metering equipment such as gas flow meters, utility meters (gas and electricity) and gas analyzers. Meters must be maintained to operate consistent with design specifications and must be calibrated on a regular basis.

(c) Data quality management must include sufficient data capture to support quantification and verification of CO_2 sequestered. Any assumptions and contingency procedures must be documented. Any monitoring plan and implementation must take into account the location, type of equipment, and frequency by which each variable is measured.

4.3.1.1. Analysis of the CO_2 Stream

(a) The GCS Project Operator must sample and analyze the CO_2 stream at a frequency sufficient to yield data representative of the chemical and physical characteristics of the injectate (i.e., at least once every quarter), whenever the result may deviate from the original certified specifications, and as requested by the Executive Officer.

(b) Analysis of the CO_2 stream must be reported in the quarterly reports pursuant to **Section 3.3.2**. The report must include characteristics such as fluid composition (i.e., fraction of CO_2 and other constituents measured on a volumetric or mass basis at a known temperature and pressure), temperature, pressure, and any other parameters needed to identify potential interactions between the injectate and the formation or well materials. The GCS Project Operator must submit, at a minimum, the following:

(1) A list of chemicals analyzed, including CO_2 and other constituents (e.g., sulfur dioxide, hydrogen sulfide, nitrogen oxides);

(2) A description of the sampling methodology, noting any differences from those listed in the Testing and Monitoring Plan and an explanation of why a different method was used;

(3) Any laboratory analytical methods used, the name of the laboratory performing the analysis, and official laboratory analytical reports including sample chain-of-custody forms;

(4) All sample dates and times;

(5) A tabulation of all available carbon dioxide stream analyses, including QA/QC samples;

(6) Interpretation of the results with respect to regulatory requirements and past results;

(7) Identification and explanation of data gaps, if any; and

(8) Any identified necessary changes to the GCS project Testing and Monitoring Plan.

(c) The report must include a determination that any potential chemical reactions between the injectate and the formation or well materials are minimal and will not significantly affect the integrity of the well or the injectivity of the formation;

(d) The report must include a determination that the injectate does not meet the qualifications of hazardous waste under the RCRA, 42 U.S.C. 6901 *et seq.* (1976), and/or CERCLA, 42 U.S.C. 9601 *et seq.* (1980); and

(e) Injectate fluid samples must be collected from a point immediately upstream or downstream of the flow meter.

4.3.1.2. Continuous Monitoring of Injection Rate and Volume

(a) The GCS Project Operator must continuously monitor the injection rate and volume for each GCS injection well.

(b) Flow rate data must be used (1) to determine the cumulative volume of CO_2 injected, and (2) to verify compliance with the operational conditions of the Permanence Certification.

(c) Monitoring requirements must include measurements of relevant parameters to account for the flow rate of injected fluids, the concentration of the fluid stream, and the energy inputs required for operation.

(d) GCS Project Operators are required to perform the following measurements and monitoring for injected fluids:

(1) Flow rate of injection stream:

(A) Continuous measurement of the gas flow rate, gas composition, and gas density, where continuous measurement is defined as a minimum of one measurement every 15 minutes;

(B) Meter readings need to be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures;

(C) Estimates of composition and density are not permissible;

(D) Flow meters must be located at the input to the gas injection process, such that they are downstream of all capture, compression, and transport to account for any fugitive losses or venting. Flow meters must be placed based on manufacturer recommendations;

(E) Flow meters must be calibrated according to manufacturer specifications. Meters must be checked/calibrated at regular intervals according to these specifications and industry standards; and

(F) Ownership transfer must be clearly documented for CO_2 transferred (third party injection activity).

(2) Concentration of injection stream:

(A) Continuous measurement of the fluid composition and density where continuous measurement is defined as a minimum of one measurement every 15 minutes; and

(B) The fluid composition must be metered downstream of the capture and processing equipment while the volume is measured as close as possible to the point where CO_2 is injected into the well.

(e) Injection rate and volume data must be submitted in the quarterly reports pursuant to **Section 3.3.2**. The report must include, at a minimum:

(1) Tabular data of all flow rate measurements and a description of interpretation of the data aided with charts or graphs;

(2) A description of the measuring methodology and technology, noting any differences from those given in the Testing and Monitoring Plan and an explanation of why a different methodology was used;

(3) The monthly average flow rate;

(4) The monthly maximum and minimum values;

(5) The total volume (mass) injected each month;

(6) The cumulative volume (mass) calculated for the GCS project;

(7) If flow rate exceeded certified operational limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion, and response to the excursion;

(8) Identification and explanation of data gaps, if any; and

(9) Any identified necessary changes to the GCS project Testing and Monitoring Plan and the justification for those changes.

4.3.1.3. Continuous Monitoring of Injection Pressure

(a) During operation, the GCS Project Operator must continuously monitor injection pressure, either at the wellhead (i.e., wellhead pressure) or downhole (i.e., bottomhole pressure).

(b) Injection pressure is monitored to ensure that the fracture pressure of the sequestration zone and the burst pressure of the well tubing are not exceeded and that the owner or GCS Project Operator is in compliance with certified operating conditions.

(c) The GCS Project Operator must insure that the injection pressure remains at or below 90 percent of the fracture pressure of the sequestration zone.

(d) During injection, pressure in the annular space directly above the packer must be maintained at least 100 to 200 psi[10] higher than the tubing pressure.

(e) Maximum allowable surface pressure must equal top perforation depth, in true vertical depth, multiplied by the difference between the injection gradient and the injectate fluid gradient.

(f) Significant changes in annulus pressure measured during injection may indicate a loss of internal mechanical integrity. If pressure monitoring indicates that the well is experiencing a loss of mechanical integrity, the GCS Project Operator must follow the procedures outlined in **Section 6.2.1**.

(g) Pressure data must be reported in the annual reports following **Section 3.3.2**. The GCS Project Operator must submit, at a minimum, the following:

(1) Tabular data of all pressure measurements, a description and interpretation of the data aided with charts or graphs, and gauge calibration records;

(2) A description of the measurement methodology, noting any differences from what was established in the Testing and Monitoring Plan, and a justification of why a different methodology was used;

(3) Corrections made due to the impacts of fluctuating injectate temperature;

(4) The monthly average value for injection pressure;

(5) The monthly maximum and minimum values for injection pressure;

(6) If pressure exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the exceedance, the length of the excursion, and response to the excursion;

(7) Identification and explanation of data gaps, if any; and

(8) Any identified necessary changes to the GCS project Testing and Monitoring Plan to ensure continued protection of public health and the environment, including any changes in the data measurement or averaging methods.

4.3.1.4. Corrosion Monitoring

(a) GCS Project Operators must perform quarterly monitoring of well materials for corrosion.

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[10] USEPA Region 8, Groundwater Section Guidance Number 39, (1995), Denver, CO.

(b) Well components must be monitored for corrosion using at least one of the following methods: corrosion coupons, loops, casing inspection logs (CIL), or an alternative method approved by the Executive Officer.

(c) Well corrosion monitoring data must be reported annually to CARB including, at a minimum, the following:

(1) A description of the techniques used for corrosion monitoring;

(2) Measurement of mass and thickness loss from any corrosion coupons or loops used;

(3) Assessment of additional corrosion, including pitting, in any corrosion coupons or loops;

(4) Measurement of thickness loss or corrosion detected in any CILs;

(5) All measured CILs and comparison to previous logs;

(6) Identification and explanation of data gaps, if any; and

(7) Any identified necessary changes to the GCS project Testing and Monitoring Plan.

4.3.1.5. Pressure Fall-Off Testing

(a) GCS Project Operators must perform a pressure fall-off test of the injection well at least once every five years pursuant to **Section 6.2**;

(b) The objective of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity and pressure increase, as anomalous pressure drops during testing may indicate fluid leakage through the wellbore;

(c) Upon shutting-in the well, pressure measurements must be taken continuously for a period of time, and pressure decay at the well must be monitored;

(d) The GCS Project Operator must use temperature and bottomhole pressure measurements, although surface pressure at the wellbore may suffice, if positive pressure is maintained throughout the test;

(e) The results of pressure fall-off tests must be reported to the Executive Officer 30 days following the test. Reports must include, at a minimum:

(1) The location and name of the test well and the date/time of the shut-in period;

(2) Depths of bottomhole pressure and temperature;

(3) Records of gauges;

(4) Raw data collected during the fall-off test in a tabular format, if required by the Executive Officer;

(5) Measured injection rates and pressure from the test well and any off-set wells in the same zone, including data from before shut-in;

(6) Information on pressure gauges used (e.g., manufacturer, accuracy, depth deployed) and demonstration of gauge calibration according to manufacturer specifications;

(7) Diagnostic curves of test results, noting any flow regimes;

(8) Description of quantitative analysis of pressure-test results, including use of any commercial software, and any considerations of multi-phase effects;

(9) Calculated parameter values from analysis, including transmissivity, permeability, and skin factor;

(10) Analysis and comparison of calculated parameter values to previously measured values (using any previous methods) and to values used in computational modeling and AOR delineation;

(11) Identification of data gaps, if any; and

(12) Any identified necessary changes to the GCS project Testing and Monitoring Plan.

4.3.1.6. Monitoring of Wellheads and Valves

(a) The GCS Project Operator must prepare, maintain, and comply with an Inspection and Leak Detection Plan for all surface equipment, including wellheads, valves, and pipelines. This Inspection and Leak Detection Plan must be approved by the Executive Officer;

(b) The Inspection and Leak Detection Plan must include, at a minimum, procedures that the GCS Project Operator will follow that include:

(1) Quarterly inspection of all wellheads, valves, and piping, employing effective gas leak detection technology;

(2) Bi-annual testing of all surface and subsurface safety valve systems to ensure ability to hold anticipated pressure; and

(3) Annual testing of the master valve and wellhead pipeline isolation valve for proper function and verification of the valve's ability to isolate the well.

(c) The plan must include inspection of the wellhead assembly and attached pipelines for each of the injection wells used in association with the GCS project, as well as the surrounding area within a 100-foot radius of the wellhead of each of the wells;

(d) The GCS Project Operator must select and use gas leak detection technology that takes into account detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, local ecology, geography, and meteorology;

(e) Upon finding that a surface or subsurface safety valve is inoperable, the GCS Project Operator must immediately shut-in the well and repair the valve within 90 days. An appropriate alternative timeframe for testing a valve or addressing an inoperable surface or subsurface safety valve may be approved by the Executive Officer;

(f) Documentation of all inspections, tests, and results must be maintained by the GCS Project Operator and available for CARB review; and

(g) Testing of surface equipment operational integrity must be conducted in accordance with API Recommended Practice 14B[11], or equivalent.

4.3.2. Monitoring, Measurement, and Verification of Containment

(a) Every GCS project must undertake monitoring activities to ensure safe and permanent storage of CO_2 in accordance with the Permanence Certification.

(b) The Measurement, Monitoring, and Verification Plan must be specific to the storage complex that CO_2 is being injected into, to ensure there are no emissions from the sequestration zone.

(c) The Monitoring, Measurement, and Verification Plan must be submitted as part of the Testing and Monitoring Plan with the application for site approval. The plan must include the methods the GCS Project Operator will perform to monitor the extent of the CO_2 plume and pressure front, the surface, and seismic activity.

(d) The Executive Officer may require the GCS Project Operator to perform additional monitoring, as necessary, to support, upgrade, and improve

[11] API Recommended Practice 14B, "Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems," 6 (2015): 37 p.

computational modeling of the AOR and to determine compliance with Permanence Certification.

4.3.2.1. Plume Tracking

(a) GCS Project Operators are required to track the extent of the free-phase CO_2 plume, and the presence or absence of elevated pressure (e.g., the pressure front) by using:

(1) Direct methods in the sequestration zone; and

(2) Indirect methods such as seismic, electrical, gravity, or electromagnetic surveys and downhole CO_2 detection tools.

(b) GCS Project Operators must select the timing of these surveys based on baseline seismic surveying prior to injection, and any previously observed storage and monitoring performance data, if available.

(c) Monitoring free-phase CO_2 plume development: GCS Project Operators must monitor the free-phase CO_2 plume, and must consider the following methods to detect the shape of CO_2 saturation of the pore space in the sequestration zone:

(1) Time-lapse three-dimensional surface seismic surveys;

(2) Downhole, time-lapse three-dimensional vertical seismic profiling surveys;

(3) Electrical resistivity (surface or downhole); and

(4) An alternative test approved by the Executive Officer.

(d) Monitoring pressure development: GCS Project Operators must monitor the pressure front of the CO_2 plume, and must consider the following methods:

(1) Satellite based synthetic aperture radar (InSAR) monitoring (satellite-based);

(2) Pressure gauges (downhole);

(3) Tilt meters or inclinometers (surface and well-based); and

(4) An alternative test approved by the Executive Officer.

(e) Plume and pressure-front tracking data must be reported quarterly for methods in which data are collected continuously or monthly, and annually for methods in which data are collected yearly (or longer), based on the monitoring timeline pursuant to **subsection 6.3.2.1(b)**. Reports must include, at a minimum:

(1) Tabular data of all measurements and a description and interpretation of the data aided with charts, graphs, and maps of the plume shape;

(2) A description of the measurement methodology, noting any differences from what was established in the Testing and Monitoring Plan, and a justification of why a different methodology was used;

(3) An assessment of any deviations from the modeled AOR, if observed, and the determination of whether or not the results trigger an AOR reevaluation; and

(4) Any identified necessary changes to the GCS project Testing and Monitoring Plan and the justification for those changes.

4.3.2.2. Surface and Near-Surface Monitoring

(f) The GCS Project Operator must monitor the surface and near-surface of a GCS project to detect potential leakage of CO_2 out of the sequestration zone.

(g) The GCS Project Operator must design of surface and near-surface monitoring based on potential risks to atmospheric CO_2 leakage within the AOR.

(h) The monitoring frequency and spatial distribution of surface and near-surface monitoring must be decided using baseline data pursuant to **Section 4.5**, and the monitoring plan must describe how the proposed monitoring will yield useful information on the AOR delineation or reevaluation.

(i) Surface air monitoring of point sources: GCS Project Operators must monitor and quantify CO_2 or other gases associated with storage complex (e.g. CH_4, in the case of injection into a hydrocarbon reservoir) in the atmosphere in order to detect potential releases from wellbores, faults, and other migration pathways. Broad aerial monitoring must focus on the footprint of the free-phase CO_2 plume, while more targeted monitoring can occur at injection wells and pipelines. GCS Project Operators must use both intermittent and continuous monitoring methods, must consider the following tools to track CO_2 in the atmosphere:

(1) Optical sensors;

(2) Infrared (IR) open-path detectors;

(3) Forward looking infrared (FLIR) cameras;

(4) Multi-spectral imaging;

(5) Atmospheric tracers, including natural and injected chemical compounds;

(6) Eddy covariance flux measurement techniques; and

(7) Alternative methods approved by the Executive Officer.

(j) Soil gas monitoring of point sources: The GCS Project Operator must perform continuous and intermittent geochemical monitoring of the soil and vadose zone, including sampling of CO_2, natural chemical tracers, and introduced tracers, in order to detect potential releases from wellbores, faults, and other migration pathways, and must consider the following methods:

(1) Flux accumulation chamber methods;

(2) Active sample collection methods including ground probes and permanent soil gas probes;

(3) Passive sample collection methods including sorbents; and

(4) Alternative methods approved by the Executive Officer.

(k) GCS Project Operators may also consider near-surface electrical conductivity surveys to measure variations in soil salinity to determine the presence or absence of brine tracers from potential brine leakage from the injection zone.

(l) Ecosystem stress monitoring: GCS Project Operators must conduct annual vegetation surveys to measure potential vegetative stress resulting from elevated CO_2 in soil or air. GCS Project Operators must consider methods such as satellite imagery, aerial photography, and spectral imagery. Any indications of anomalous change from remote sensing must be subject to ground-based verification and, if necessary, soil samples must be analyzed to determine the presence or absence of injection zone brine or artificial tracers injected with the CO_2.

(m) Surface and near-surface monitoring data must be reported quarterly for methods in which data are collected continuously, and annually for methods in which data are collected less frequently, based on the monitoring timeline pursuant to **subsections 6.3.2.2(d), (e),** and **(g)**. Reports must include, at a minimum:

(1) Tabular data of all measurements and a description and interpretation of the data aided with charts, graphs, and maps of sample collection locations;

(2) A description of the measurement methodology, noting any differences from what was established in the Testing and Monitoring Plan, and a justification of why a different methodology was used;

(3) An assessment of any deviations from the modeled AOR, if observed, and the determination of whether or not the results trigger an AOR reevaluation;

(4) Any identified necessary changes to the GCS project Testing and Monitoring Plan and the justification for those changes;

(5) If data indicate a surface leak of CO_2 from the storage complex, the GCS Project Operator must perform all actions necessary to identify and remediate the leak following the Emergency and Remedial Action Plan in **Section 8**.

4.3.2.3. Seismicity Monitoring

(a) The GCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system in order to verify the presence or absence of any induced microseismic activity within the vicinity of each injection well.

(b) From commencement of injection activity to its completion, the GCS Project Operator must continuously monitor for an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations.

(1) An GCS Project Operator in California must continuously monitor the California Integrated Seismic Network;

(2) For GCS projects located out of California, the GCS Project Operator must continuously monitor the U.S. Geological Survey's National Earthquake Information Center and Advanced National Seismic System, or equivalent.

(c) If an earthquake of magnitude 2.7 or greater is identified under **subsection 6.3.2.3(b)**, the following requirements apply:

(1) The GCS Project Operator must immediately notify the Executive Officer when and where (i.e., the epicenter and hypocenter) the earthquake occurred;

(2) CARB, in consultation with the GCS Project Operator and the California Geological Survey, or local geological survey or equivalent, will conduct an evaluation of the following:

(A) Whether there is indication of a causal connection between the injection activity and the earthquake;

(B) Whether there is a pattern of seismic activity in the area that correlates with nearby injection activity; and

(C) Whether the mechanical integrity of any well, facility, or pipeline within the radius specified in **subsection 6.3.2.3(a)** has been compromised.

(d) If the GCS Project Operator obtains evidence that an earthquake has caused a failure of the mechanical integrity of the injection well, facility, or pipeline, which may cause potential CO_2 emissions to the atmosphere, the GCS Project Operator must implement the Emergency Remedial Response Plan pursuant to **Section 8**.

(e) The results of the seismic evaluation must be reported to the Executive Officer 30 days following the earthquake. The report must include, at a minimum:

(1) The date, time, and magnitude of the earthquake;

(2) The location and distance of the epicenter from the GCS project;

(3) The results of the investigation into the link between the injection activity and the earthquake or pattern of seismicity;

(4) Any emergency and remedial actions taken pursuant to **Section 8**;

(5) A description of any investigations and tests conducted to assess the mechanical integrity of injection wells and other surface equipment, and a demonstration that the well and equipment were either not damaged by the earthquake or that mechanical integrity was restored prior to the re-initiation of injection; and

(6) Any identified changes necessary to the GCS project Testing and Monitoring Plan.

5. Well Plugging, Post-Injection Site Care and Site Closure

5.1. Well Plugging

(a) Well Plugging Plan: The GCS Project Operator must prepare, maintain, and comply with a plan to plug all injection, production, and monitoring wells associated with the GCS project that is acceptable to the Executive Officer.

(b) The GCS Project Operator must demonstrate in the plan that each well will be plugged in a manner that prevents the well from serving as a conduit for fluid or gas migration out of the sequestration zone.

(c) The Well Plugging Plan must be submitted as part of the application for site approval, and the plan must be updated as needed throughout the life of the GCS project.

(d) The Well Plugging Plan must include the following information:

(1) Appropriate tests or measures for determining bottomhole pressure. Bottomhole pressure must be used to determine the appropriate density of plugging fluids to achieve static equilibrium prior to plug placement;

(2) Appropriate testing methods to ensure external mechanical integrity as specified in **Section 6.2**. External mechanical integrity testing is required to ensure that the long-string casing and cement left in the ground after the well is plugged will maintain their integrity over time;

(3) The type and number of plugs to be used;

(4) A description and depiction of the placement of each plug, including the elevation of the top and bottom of each plug;

(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the CO_2 stream; and

(6) The method of plug placement.

(e) The GCS Project Operator must consider the following when developing the Well Plugging Plan:

(1) The location and thickness of the lowermost sequestration zone and freshwater aquifer-containing strata, which dictate the location of all plugs;

(2) Well construction details, particularly the depth of the bottom of the intermediate and surface casings, which would affect the number of plugs and the types and amount of cement needed;

(3) Types of subsurface formations penetrated by the well and their geochemistry, which may influence both plugging methods and the types of cement needed (for open-hole plugging); and

(4) The composition of the CO_2 stream and formation fluid geochemistry, including any geochemical changes anticipated during the post-injection period, which can affect appropriate plugging and cementing materials.

(f) Prior to the well plugging, the GCS Project Operator must flush each GCS injection well with a buffer fluid, determine bottomhole pressure, and perform a final external mechanical integrity test.

(g) Prior to plugging each well, the GCS Project Operator must consider the operational and monitoring history of the GCS project and identify whether any information or events warrant amendment of the original Well Plugging Plan. Data that must be considered include:

(1) Monitoring data related to chemistry of the CO_2 plume and formation fluids;

(2) Mechanical integrity testing, including any mechanical integrity problems that may have occurred during the injection phase of the GCS project;

(3) Operational data, such as injection rates or volumes; and/or

(4) Any significant changes to the GCS project that may affect plugging of a well.

(h) Notice of intent to plug: The GCS Project Operator must notify the Executive Officer in writing pursuant to **Section 3.3**, at least 30 days before plugging, conversion, or abandonment of a well. At the discretion of the Executive Officer, a shorter notice period may be allowed.

(i) Amending the Well Plugging Plan: If the GCS Project Operator finds it necessary to change the Well Plugging Plan, a revised plan must be submitted at the same time as providing the notice of intent, pursuant to **Section 3.3**, to the Executive Officer for written approval.

(j) The GCS Project Operator must receive written approval of the Executive Officer before plugging the well, and must plug and abandon the well in accordance with **subsections 7.1(d)** through **(g)** in this section, as provided in the Well Plugging Plan.

(k) Plugging report: Within 60 days after plugging, the GCS Project Operator must submit, pursuant to **Section 3.3**, a plugging report to the Executive Officer. The report must be certified as accurate by the GCS Project Operator and by the person who performed the plugging operation (if other than the GCS Project Operator). The GCS Project Operator must retain the well plugging report for 10 years following site closure. The report must include:

(1) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Executive Officer; or

(2) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted; and

(3) A statement that the well was inspected using approved detection methods and found to have no leaks.

(l) Temporary Abandonment: The GCS Project Operator must continue to comply with the conditions of the Permanence Certification, including all monitoring and reporting requirements according to the frequencies outlined in the Permanence Requirements and documentation. The well must also be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in **Section 6.2**.

(1) After a cessation of operations of 24 months, the GCS Project Operator must plug and abandon the well, or group of wells, in accordance with the Executive Officer-approved Well Plugging Plan unless he or she:

(A) Provides notice to CARB; and

(B) Describes actions or procedures, satisfactory to CARB, which the GCS Project Operator will take to ensure that the well will not endanger public health and/or the environment during the period of temporary abandonment. These actions and procedures must include compliance with the technical requirements applicable to active wells unless waived by CARB.

5.2. Post-Injection Site Care and Site Closure

(a) The GCS Project Operator must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of **subsection 5.2(a)(2)**.

(1) The GCS Project Operator must submit the Post-Injection Site Care and Site Closure Plan as a part of the application for site approval.

(2) Post-Injection Site Care and Site Closure Plan. The plan for site care and closure must include the following information:

(A) The pressure differential between pre-injection and predicted post-injection pressures in the sequestration zone, and the predicted timeframe in which pressure is expected to decrease to pre- or close to pre-injection levels;

(B) A depiction of the predicted position of the CO_2 free-phase plume and associated pressure front at site closure as demonstrated in the AOR evaluation and computational modeling required at **Sections 2.4** and **2.4.1**;

(C) A description of post-injection monitoring location, methods, and proposed frequency; and

(D) A proposed schedule for submitting post-injection site care monitoring results to the Executive Officer.

(3) Upon injection completion, the GCS Project Operator must either submit an amended Post-Injection Site Care and Site Closure Plan or demonstrate to

the Executive Officer through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the Post-Injection Site Care and Site Closure Plan must be approved by the Executive Officer and incorporated into the Permanence Certification.

(4) At any time during the life of the GCS project, the GCS Project Operator may modify and resubmit the Post-Injection Site Care and Site Closure Plan for the Executive Officer's approval within 30 days of such change.

(b) Post-injection site care and monitoring:

(1) The GCS Project Operator must monitor the site following injection completion to determine the position of the free-phase CO_2 plume and pressure front, and demonstrate that no credited fluids are leaking out of the sequestration zone, as specified in the Testing and Monitoring Plan and the Post-Injection Site Care and Site Closure Plan.

(2) After injection is complete, the GCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan for a minimum of 100 years.

(3) Post-injection site care and monitoring requirements are as follows:

(A) Within 24 months after injection is complete, all injection (and production, if applicable) wells associated with the GCS project must be plugged and abandoned pursuant to the Well Plugging Plan specified in **subsection 5.1(d)**.

(B) Monitoring wells must remain open, and in active monitoring mode for at least 15 years and until CARB agrees that plume stability has occurred.

(C) If a monitoring well is discovered to be leaking at any time during the 15 year period, the GCS Project Operator must take all necessary measures to identify the cause of the leak and remediate it. If the leak cannot be remediated, the well must immediately be plugged and abandoned pursuant to Section (Well Plugging Plan).

(D) The GCS Project Operator must conduct quarterly bottomhole pressure tests and groundwater sampling in the monitoring wells, in order to track the position of the free-phase CO_2 plume and pressure front. Once the CO_2 plume has remained stable for five consecutive years, well and groundwater monitoring may decrease to once per year, for a total of at least 15 years after injection is complete.

(E) At one year, three years, five years, and every subsequent five years after injection is complete, for a total of at least 15 years, the GCS Project Operator must use three-dimensional surface seismic methods to map the position of the free-phase CO_2 plume and pressure front.

(F) The results from the direct and indirect monitoring methods described in **subsections 5.2(b)(3)(D)** and **(E)** must be used to update the AOR delineation pursuant to **Section 2.4**, determine if any corrective action is necessary, and to establish if the CO_2 plume has stabilized.

(G) After plume stability is established, and at least 15 years after injection is complete, the monitoring wells must be plugged and abandoned pursuant to the Well Plugging Plan in **subsection 5.1(d).**

(H) The GCS Project Operator is required to conduct leak detection checks at each well that is part of the GCS project, and in the near surface close to each well, annually for 100 years after injection is complete. Monitoring must include:

1. Soil-gas and surface-air monitoring at, and within 10 ft of, the wellhead; and

2. Visual inspection of the wellhead and the land surface within a 100 ft radius of the well.

(I) The GCS Project Operator must submit the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan.

(c) Notice of intent for site closure. The GCS Project Operator must notify the Executive Officer at least 120 days before site closure. At this time, if any changes have been made to the original Post-Injection Site Care and Site Closure Plan, the GCS Project Operator must also provide the revised plan. The Executive Officer may allow for a shorter notice period.

(d) After the Executive Officer has authorized site closure, the GCS Project Operator must plug all monitoring wells as specified in the Post-Injection Site Care and Site Closure Plan, in a manner in which will not allow movement of injection or formation fluids out of the sequestration zone into the subsurface that is likely to reach the atmosphere. At the direction of the Executive Officer, the GCS Project Operator must also restore the site to its pre-injection condition.

(e) The GCS Project Operator must submit a site closure report to the Executive Officer within 90 days of site closure, which must thereafter be retained at a location designated by the Executive Officer for 10 years. The report must include:

(1) Documentation of appropriate injection and monitoring well plugging as specified in **Section 5.1 and subsections 5.2(b)(3)(A)** and **(G)**. The GCS Project Operator must provide a copy of a survey plat, which has been submitted to the local zoning authority designated by the Executive Officer. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks;

(2) Documentation of appropriate notification and information to such state, federal, local, and tribal authorities that have authority over drilling activities to enable such state, federal, local, and tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the sequestration and confining layers; and

(3) Records reflecting the nature, composition, and volume of the CO_2 stream.

(f) Each GCS Project Operator must record a notation on the deed to the GCS project property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:

(1) The fact that land has been used to sequester CO_2;

(2) The name of the state agency and local authority with which the survey plat was filed; and

(3) The volume of fluid injected, the sequestration zone into which it was injected, and the period over which injection occurred.

(g) The GCS Project Operator must retain for 10 years following site closure, records collected during the post-injection site care period. The GCS Project Operator must deliver the records to the Executive Officer at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Executive Officer for that purpose.

6. Emergency and Remedial Response

(a) As part of the application for site approval, the GCS Project Operator must provide the Executive Officer with an Emergency and Remedial Response Plan that describes actions the GCS Project Operator must take to address movement of the injection or formation fluids that may cause an endangerment public health and the environment during construction, operation, and post-injection site care periods.

(b) If the GCS Project Operator obtains evidence that the injected CO_2 stream, free-phase plume, or pressure front may cause an endangerment to public health and the environment, either by brine or CO_2 leakage outside of the sequestration zone, the GCS Project Operator must:

(1) Immediately cease injection;

(2) Take all steps reasonably necessary to identify, characterize, and quantify any release;

(3) Notify the Executive Officer in writing within 24 hours; and

(4) Implement the Emergency and Remedial Response Plan.

(c) The Executive Officer may allow the GCS Project Operator to resume injection prior to remediation if the GCS Project Operator demonstrates that the injection operation will not endanger public health and the environment.

(d) The GCS Project Operator must periodically review the Emergency and Remedial Response Plan developed under **subsection 6(a)**, which must include:

(1) At a frequency specified in the AOR and Corrective Action Plan, or more frequently when monitoring, operational, or other relevant conditions warrant, the GCS Project Operator must review and update the Emergency and Remedial Response Plan or demonstrate to the Executive officer that no update is needed. The GCS Project Operator must also incorporate monitoring, operational data, or other relevant data and in response to AOR reevaluations required under **Section 4.4.5** or demonstrate to the Executive Officer that no update is needed. The amended Emergency and Remedial Response Plan or demonstration must be submitted to the Executive Officer as follows:

(A) Within one year of an AOR reevaluation;

(B) Following any significant changes to the GCS project, such as addition of injection or monitoring wells, on a schedule determined by the Executive Officer; or

(C) When required by the Executive Officer.

(e) Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the GCS Project Operator must submit the resultant information to the Executive Officer for review and confirmation of the results.

6.1. Emergency and Remedial Response Requirements

(a) The Emergency and Remedial Response Plan must describe actions that the GCS Project Operator must take to prevent unexpected CO_2 movement at the site in the response to site risk assessment and risk analysis and any actions to be taken if the unexpected movement occurs. The plan must include:

(1) A list and description of possible risk scenarios that could potentially call for emergency response at the site, including but not limited to:

(A) Injection or monitoring well integrity failure;

(B) Injection well monitoring equipment failure;

(C) CO_2 leakage to the land surface and atmosphere; or

(D) A natural disaster with effects that could impact site operations.

(2) A list and description of the potential consequences of the risk scenarios.

(3) A list and description of local resources and infrastructure that may be impacted as a result of an emergency at the GCS project site, including but not limited to:

(A) Freshwater aquifers, potable water wells, surface water such as rivers or lakes, farmland, and public land or nature preserves; and

(B) Residential areas, commercial properties, recreational facilities, topographic depressions, and basements.

(4) A list and description of any steps needed to identify, characterize, and respond to each potential risk scenario listed pursuant to **subsection 8.1(a)(2)** in this section, including:

(A) Emergency identification, for example:

1. Activation of automatic shutdown devices due to well integrity failure;

2. Malfunction of monitoring equipment for pressure or temperature that may indicate a problem with the injection well and possible endangerment of public health and the environment;

3. Detections of elevated concentrations of CO_2 or other evidence of CO_2 leakage to the land surface;

4. Detections of elevated values of indicator parameters in groundwater samples or other evidence of brine or CO_2 leakage into freshwater aquifers or surface water; or

5. A natural disaster such as a weather-related disasters that may impact surface facilities or an earthquake that may disturb subsurface facilities.

(B) Response actions planned, including but not limited to:

1. Notification of the site supervisor or designee;

2. Notification of the Executive Officer in writing within 24 hours of the emergency event, per **subsection 8(b)(3)**;

3. Initial assessment of the situation by the site supervisor or designee and the determination of which other GCS project personnel to notify;

4. The determination of the severity of the event, based on the information available by the site supervisor or designee, within 24 hours of the event;

5. Emergency and remedial actions to be taken to stop or limit the risk of endangerment to public health and the environment due to the type and severity of the event.

(5) A list site personnel, GCS project personnel, and local authorities, and their contact information.

(6) A list of any special equipment needed in the event of an emergency. The type of equipment needed in the event of an emergency, as remedial response varies depending on the triggering event. Response actions (e.g., injection completion or hiatus, well shut-in, or evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig) is required, the designated Project Manager must be responsible for its procurement.

(7) A site specific emergency communications plan, including the designation of a public and media communications liaison, which must be developed and maintained throughout the life of the GCS project.

(8) The timeline for review of the Emergency and Remedial Response Plan, not to exceed less than once every five years following its approval by the permitting agency, within one year following and AOR reevaluation, and within a prescribed period to be determined by CARB following any significant changes to the injection process or GCS project. If the review indicates that

no amendments to the Emergency and Remedial Response Plan are necessary, the GCS Project Operator must provide the Executive Officer with the documentation supporting a determination of no necessary amendments. If the review indicates that amendments to the Emergency and Remedial Response Plan are necessary, amendments must be made and submitted to the CARB within one year following an event that initiates the Emergency and Remedial Response Plan review procedure.

7. Financial Responsibility

(a) The GCS Project Operator of a certified GCS project must demonstrate and maintain financial responsibility and resources as determined by the Executive Officer that meets the following conditions:

(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:

(A) Trust Funds;

(B) Surety Bonds;

(C) Letter of Credit;

(D) Insurance;

(E) Self-Insurance (i.e., Financial Test and Corporate Guarantee);

(F) Escrow Account; and

(G) Any other instrument(s) satisfactory to the Executive Officer.

(2) The qualifying instrument(s) must be sufficient to cover the cost of:

(A) Corrective action (that meets the requirements of **Section 4.4.4**);

(B) Well plugging (that meets the requirements of **Section 7.1**);

(C) Post-injection site care and site closure (that meets the requirements of **Section 7.2**); and

(D) Emergency and remedial response (that meets the requirements of **Section 8**).

(3) The financial responsibility instrument(s) must be sufficient to address the potential endangerment of public health and the environment via atmospheric leakage.

(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.

(A) Protective conditions of coverage must include at a minimum: cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew (with a new qualifying financial instrument), as well as requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

1. For purposes of this part, a GCS Project Operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail and an electronic format to the GCS Project Operator and the Executive Officer. The cancellation must not be final for 120 days after receipt of cancellation notice. The GCS Project Operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Executive Officer.

2. For purposes of this part, the GCS Project Operator must renew all financial instruments, if an instrument expires, for the entire term of the GCS project. The instrument may be automatically renewed as long as the GCS Project Operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

3. Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: (1) the Executive Officer deems the GCS project abandoned, (2) the permit is terminated or revoked or a new permit is denied, (3) closure is ordered by the Executive Officer or a U.S. district court or other court of competent jurisdiction, (4) the GCS Project Operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, or (5) the amount due is paid.

(5) The qualifying financial responsibility instrument(s) must be approved by the Executive Officer.

(A) The Executive Officer must consider and approve the financial responsibility demonstration for all the phases of the GCS project prior to certification following **Section 3.2**.

(B) The GCS Project Operator must provide updated information related to their financial responsibility instrument(s) when/if there are any changes. This information must be provided to the Executive Officer within 30 days of such a change. The Executive Officer must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The GCS Project Operator must maintain financial responsibility requirements regardless of the status of the Executive Officer's review of the financial responsibility demonstration.

(C) The Executive Officer may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.

(6) The GCS Project Operator must demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the GCS project.

(A) In the event that the GCS Project Operator combines more than one instrument for a specific GCS phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self-insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.

(B) When using a third-party instrument to demonstrate financial responsibility, the GCS Project Operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings, or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(C) A GCS Project Operator using certain types of third-party instruments must establish a standby trust to enable CARB to be party to the financial responsibility agreement without CARB being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.

(D) A GCS Project Operator may deposit money to an escrow account to cover financial responsibility requirements, and this account must segregate funds sufficient to cover estimated costs for GCS project financial responsibility from other accounts and uses.

(E) A GCS Project Operator or its guarantor may use self-insurance to demonstrate financial responsibility for GCS projects. In order to satisfy this requirement the GCS Project Operator must meet a tangible net worth of an amount approved by the Executive Officer, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the GCS Project Operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's, Aaa, Aa, A, or Baa as issued by Moody's, or meet all of the following five financial ratio thresholds: (1) A ratio of total liabilities to net worth less than 2.0, (2) a ratio of current assets to current liabilities greater than 1.5, (3) a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1, (4) A ratio of current assets minus current liabilities to total assets greater than −0.1, and (5) a net profit (revenues minus expenses) greater than 0.

(F) A GCS Project Operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent’s demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligation for the GCS Project Operator.

(G) A GCS Project Operator may obtain an insurance policy to cover the estimated costs of GCS activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.

(b) The GCS Project Operator must maintain financial responsibility and resources until:

(1) The Executive Officer receives and approves the completed Post-Injection Site Care and Site Closure Plan; and

(2) The Executive Officer approves site closure.

(c) The GCS Project Operator may be released from financial instrument in the following circumstances:

(1) The GCS Project Operator has completed the phase of the GCS project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Executive Officer, including obtaining financial responsibility for the next phase of the GCS project, if required; or

(2) The GCS Project Operator has submitted a replacement financial instrument and received written approval from the Executive Officer accepting the new financial instrument and releasing the GCS Project Operator from the previous financial instrument.

(d) The GCS Project Operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the AOR, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.

(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the GCS Project Operator.

(2) During the active life of the GCS project, the GCS Project Operator must adjust the cost estimate for inflation within 60 days prior to the anniversary data of the establishment of the financial instrument(s) used to comply with **subsection 9(a)** and provide this adjustment to the Executive Officer. The GCS Project Operator must also provide the Executive Officer written updates of adjustments to the cost estimate within 60 days of any amendments to the AOR and Corrective Action Plan, the Injection Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, and the Emergency and Remedial Response Plan.

(3) The Executive Officer must approve any decrease or increase to the initial cost estimate. During the active life of the GCS project, the GCS Project Operator must revise the cost estimate no later than 60 days after the Executive Officer has approved the request to modify the AOR and Corrective Action Plan, the Injection Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, and the Emergency and Remedial Response Plan, if the changes in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Executive Officer. Any decrease to the value of the financial assurance instrument must first be approved by the Executive officer. The revised cost estimate must be adjusted for inflation as specified at **subsection 9(c)(2)**.

(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the GCS Project Operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Executive Officer, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the GCS Project Operator has received written approval from the Executive Officer.

(e) The GCS Project Operator must notify the Executive Officer by an electronic format and certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry our injection well plugging and post-injection site care and site closure.

(1) In the event that the GCS Project Operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the GCS Project Operator must notify the Executive Officer by certified mail and an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the GCS Project Operator as debtor, within 10 days after commencement of the proceeding.

(2) A guarantor of a corporate guarantee must make such a notification to the Executive Officer if he/she is named as debtor, as required under the terms of the corporate guarantee.

(3) A GCS Project Operator who fulfills the requirements of **subsection 9(a)** by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The GCS Project Operator must establish other financial assurance within 60 days after such an event.

(f) The GCS Project Operator must provide an adjustment of the cost estimate to the Executive Officer within 60 days of notification by the Executive Officer, if it is determined that the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by **Section 4.4.4**), injection well plugging (as required by **Section 7.1**), post-injection site care and site closure (as required by **Section 7.2**), and emergency and remedial response (as required by **Section 8**).

(g) The Executive Officer must approve the use and length of pay-in-periods for trust funds or escrow accounts.

8. Modification or Revocation and Reissuance of Permanence Certification

(a) When the Executive Officer receives any information, including but not limited to, (1) information submitted by the GCS Project Operator as required by the Permanence Certification, (2) receives a request for modification or r evocation and reissuance of the Permanence Certification, or (3) inspects the facility or conducts a review of the Permanence Certification, he or she may determine whether or not one or more of the causes listed in **subsections 10(b)** and **(c)** of this section exist requiring a modification or revocation and reissuance of the Permanence Certification, or both. If cause exists, the Executive Officer may modify or revoke and reissue the Permanence Certification accordingly, and may request an updated Permanence Certification if necessary. When a Permanence Certification is modified, only the conditions subject to modification are reopened. If a Permanence Certification is revoked and reissued, the entire Permanence Certification is reopened and subject to revision and the permit is reissued for a new term. Except as provided in **Section 10.2**, if cause does not exist under this Section, the Executive Officer must not modify or revoke and reissue the Permanence Certification. If a Permanence Certification modification satisfies the criteria in **Section 10.2** for "minor modifications," the Permanence Certification may be modified without a draft Permanence Certification and public review. Otherwise, the Executive Officer must post the draft Permanence Certification for public comment for at least 15 days, address those comments if considered valid, and then issue an executive order endorsing the permanence of the GCS project.

(b) Causes for modification or revocation and reissuance.

(1) Alterations. There are material and substantial alterations or additions to the certified GCS project or activity which occurred after issuance of the Permanence Certification, which justify the application of conditions that are different or absent in the existing Permanence Certification.

(2) Information. Permanence Certifications may be modified during their terms for this cause only if the information was not available at the time of issuance of the Permanence Certification (other than revised regulations, guidance, or test methods) and would have justified the application of different conditions of Permanence Certification at the time of issuance.

(3) New regulations. The standards or regulations on which the Permanence Certification was based have been changed by promulgation of new or amended standards or regulations or by judicial decision after the Permanence Certification was issued.

(4) Compliance schedules. The Executive Officer determines good cause exists for modification of a compliance schedule, such as an act of God, strike, flood, or materials shortage or other events over which the certified GCS Project Operator has little or no control and for which there is no reasonably available remedy. (See also **subsection 10.2(a)(3)**.

(5) Basis for modification of Permanence Certifications. Additionally, whenever the Executive Officer determines that changes to the Permanence Certification are necessary, based on:

(A) AOR reevaluations under **Section 4.4.5**;

(B) Any amendments to the Testing and Monitoring Plan under **Section 6.1**;

(C) Any amendments to the Injection Well Plugging Plan under **Section 7.1**;

(D) Any amendments to the Post-Injection Site Care and Site Closure Plan under **Section 7.2**;

(E) Any amendments to the Emergency and Remedial Response Plan under **Section 8**;

(F) A review of monitoring and/or testing results conducted in accordance with Permanence Certification requirements.

(c) Causes for modification or revocation and reissuance of Permanence Certification. Cause exists to modify or, alternatively, revoke and reissue Permanence Certification if the Executive Officer determines cause exists for termination under **subsection 10.1(a)**, and the Executive Officer determines that modification or revocation and reissuance is appropriate.

8.1. Termination of Permanence Certifications

(a) The Executive Officer may terminate a Permanence Certification during its term, or deny a Permanence Certification renewal application for the following causes:

(1) Noncompliance by the GCS Project Operator with any condition of the Permanence Certification;

(2) The GCS Project Operator’s failure in the application or during the Permanence Certification issuance process to disclose fully all relevant facts, or the GCS Project Operator's misrepresentation of any relevant facts at any time; or

(3) A determination that any GCS injection activity endangers public health or the environment via a leak of CO_2 or formation fluid outside of the sequestration zone, and can only be regulated to acceptable levels by modification or termination of Permanence Certification.

8.2. Minor Modification of Permanence Certifications

(a) Upon the consent of the GCS Project Operator, the Executive Officer may modify a Permanence Certification to make the corrections or allowances for changes in the certified GCS project activity listed in this section, without following the procedures of **subsection 10(a)**. Any modification to the Permanence Certification not processed as a minor modification under this section must be made for cause and pursuant to draft Permanence Certification and public notice as required in **subsection 10(a)**. Minor modifications may only:

(1) Correct typographical errors;

(2) Require more frequent monitoring or reporting by the GCS Project Operator;

(3) Change an interim compliance date in a schedule of compliance, provided the new date is not more than 120 days after the date specified in the existing Permanence Certification and does not interfere with attainment of the final compliance date requirement; or

(4) Allow for a change in ownership or operational control of a GCS project where the Executive Officer determines that no other change in Permanence Certification is necessary, provided that a written agreement containing a specific date for transfer of responsibility, coverage, and liability between the current and new GCS Project Operator has been submitted to the Executive Officer.

(5) Change quantities or types of fluids injected which are within the capacity of the facility as certified and, in the judgment of the Executive Officer, would not interfere with the operation of the GCS project or its ability to meet conditions described in the Permanence Certification.

(6) Change in construction requirements approved by the Executive Officer, provided that any such alteration must comply with the requirements of this **section** and **Section 5.1**.

(7) Amend a plugging and abandonment plan which has been updated under **Section 7**.

(8) Amend a GCS injection well Testing and Monitoring Plan, Plugging Plan, Post-Injection Site Care and Site Closure Plan, or Emergency and Remedial

Response Plan where the modifications merely clarify or correct the plan, as determined by the Executive Officer.

9. Legal Understanding, Contracts, and Post-Closure Care

(a) The GCS Project Operator must show proof of exclusive right to use the pore space in the injection zone for storing CO_2 permanently;

(b) Full disclosure must be made to inform future land management or development within AOR. For example, the restrictions and disclosure must be recorded on the deeds of the land when no regulations are in place to address this issue; and

(c) The GCS Project Operator must show proof that there is binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the injection zone are prohibited within the AOR to ensure public safety and the permanence of stored CO_2.

APPENDIX A

FUGITIVE AND VENTED GHG EMISSIONS: CARBON CAPTURE, PIPELINE TRANSPORT AND INJECTION INTO DEPLETED OIL AND GAS AND SALINE FORMATIONS

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Appendix A. Fugitive and Vented GHG Emissions: Carbon Capture, Pipeline Transport and Injection into Depleted Oil and Gas and Saline Formations

(1) Fugitive CO_2 Emissions: Equipment Count Method

Count each component (e.g., valves, connectors, open-ended lines) individually for the facility and multiply with default emission factors specific to component type. Alternatively, count the number of major pieces of equipment and multiply by the average number of components per major piece of equipment to arrive at the total number of each component for a facility. Calculate fugitive CO_2 emissions using **Equation A7**.

$$E_{s,i} = \sum Count_i \times EF_i \times C_{CO2} \times T_s \quad \text{(A7)}$$

Where:

$E_{s,i}$ = Annual volumetric fugitive CO_2 emissions at standard conditions from i[th] component in cubic feet.

$Count_i$ = Total number of i[th] component at the facility.

EF_i = Emission factor for i[th] component (scf/hour). Use a default CO_2 emission factor if available. Methane emission factors can be used as proxy for CO_2 emission factors.

C_{CO2} = CO_2 concentration (%).

T_s = Total time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$E_{s,i}$ must be converted to MT CO_2/year using the method described in **Appendix C** to obtain estimate $CO_{2_{fugitive}}$ included in previous equations.

(2) Vented Emissions: Event-Based Approach

Calculate vented CO_2 emissions by measuring/estimating CO_2 emissions per venting event, and account for CH_4 emissions for all venting events at storage site per year using **Equation A8**.

$$GHG_{vent} = \sum_{i=1}^{n} Vi \quad \text{(A8)}$$

Where:

GHG_{vent} = Annual vented CO_2 and CH_4 emissions (MT CO_2e/year).

Vi = Vented CO_2 and CH_4 emissions for i[th] vented event (MT CO_2e/event).

APPENDIX B

CO_2 VENTING AND FUGITIVE EMISSIONS FROM CO_2-EOR OPERATIONS

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Appendix B. CO_2 Venting and Fugitive Emissions from CO_2-EOR Operations

(1) Metered natural gas pneumatic device and pump vented CO_2 emissions.

a. Calculate CO_2 emissions from a natural gas-powered continuous high bleed control device and pneumatic pump vented using the method specified in paragraph (a)(1) of section 95153 in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR)[12] when the natural gas flow to the device is metered.

(2) Non-metered natural gas pneumatic device vented emissions.

a. Calculate CO_2 emissions from all non-metered natural gas-powered pneumatic intermittent bleed and continuous low and high bleed devices using the equation in paragraph 95153(a)(2) of MRR.

(3) Acid gas removal vents.

a. For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through a flare, engine (e.g., permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using the applicable calculation methodologies described in paragraphs 95153(c)(1)-(c)(10) of MRR.

(4) Dehydrator vents.

a. Calculate annual CO_2 emissions using any of the calculation methodologies described in paragraph 95153(d) of MRR.

(5) Gas well vented CO_2 emissions during well completions and workovers.

a. Use either the Methodology 1 or 2 described in paragraphs 95153(f)(1)-(f)(5) of MRR.

(6) Equipment and pipeline blowdowns.

a. Calculate CO_2 blowdown emissions from depressurizing equipment and natural gas pipelines to reduce system pressure for shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control vented and blowdown of non-GHG gases; desiccant dehydrator

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[12] CARB, 2014. Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. Unofficial electronic version available at http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-2014-unofficial-02042015.pdf

blowdown vented before reloading is covered in paragraphs 95153 (d)(4) of MRR.

(7) Dump valves.

a. Calculate CO_2 emissions from gas-liquid separator liquid dump valves not closing by using the method found in 95153(i) of MRR.

(8) Well testing vented emissions.

a. Calculate CO_2 vented from oil well testing using the methods found in paragraphs of 95153(j)(1)-(j)(6) of MRR.

(9) Associated gas.

a. Calculate CO_2 in associated gas vented not in conjunction with well testing using the methods found in paragraphs of 95153(k)(1)–(k)(6) of MRR.

(10) Centrifugal compressor vented emissions.

a. Calculate CO_2 emissions from both wet seal and dry seal centrifugal compressor using the methods described in paragraphs of 95153(m)(1)–(m)(8) of MRR.

(11) Reciprocating compressor vented emissions.

a. Calculate CO_2 emissions from all reciprocating compressor vents using the methods described in paragraphs of 95153(n)(1)–(n)(7) of MRR.

(12) EOR injection pump blowdown emissions.

a. Calculate CO_2 pump blowdown emissions from EOR operations using critical CO_2 injection using equation 33 as described in section 95153(u) of MRR.

(13) Fugitive CO_2 emissions from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

a. Perform leak detection tests in accordance with procedures as described in the MRR. If leakage is detected from the equipment listed above during annual leak detection tests, calculate fugitive emissions (CO_2) per component type in which leak is detected using Equation 25 in section 95153(o) of MRR for each component type. Default fugitive emission factors for Equation 25 are reported in Tables A4 to A6; or

b. Calculate fugitive emissions from all equipment using the population count and emission factors as described in section 95153(p) of MRR.

APPENDIX C

CONVERTING VOLUME OF CO_2 TO MASS

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Appendix C. Converting volume of CO_2 to mass

When volumetric emissions of CO_2 are measured at actual temperatures and pressures, convert them to volumetric emissions at standard conditions (25°C and 1 atm) using Equations 29 and 30 in MRR.

Calculate GHG mass emissions by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 32 described in section 95153 (t) of MRR.

APPENDIX D

DATA MEASUREMENT/GENERATION AND REPORTING FOR ENERGY AND CHEMICAL INPUTS

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Appendix D. Data Measurement/Generation and Reporting for Energy and Chemical Inputs

(1) Amounts of fuels used:

a. Fuel receipts/invoices or flow meter readings whichever applicable;

b. The flow meter readings must be corrected for temperature and pressure. Density estimates used for emission quantification purposes must be adjusted to corrected standardized temperatures and pressures;

c. Flow meters must be placed based on manufacturer recommendations and must operate within manufacturers specified operating conditions at all times; and

d. Flow meters must be calibrated according to manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

e. In cases where the same fuel is used for CCS and other unrelated activities and share the same meter or receipts/invoices, or when fuel receipts/invoices or metered data are not available, estimates with justification for the chosen methodology can be used with approval from the Executive Officer.

(2) Electricity consumption:

a. Utility receipts/invoices or metered data for off-grid electricity use. In the absence of these data, maximum power rating for each type of equipment and operating hours can be used to estimate electricity use with approval from the Executive Officer.

b. In certain cases other loads may be tied into the same electricity meter. In such instances, estimates with justification for the chosen methodology can be used with approval from the Executive Officer.

c. Electricity meters must be calibrated in accordance with manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(3) Steam consumption:

a. Utility receipts/invoices or metered data for on-site steam production whichever applicable.

b. In the absence of utility receipts/invoices or metered data, estimates with justification for the chosen methodology can be used with approval from the Executive Officer.

c. If metered data are used, meters must be calibrated in accordance with manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(4) Cogeneration:

If any part of the CCS project uses electricity and thermal energy supplied directly by co-generation, the amount of fuel use associated with the electricity and thermal energy must be estimated using Equation D1.

$$Fuel_i = Total\ Fuel_{cogen} \times \frac{Heat_{CCS} + Electricity_{CCS}}{Heat_{cogen} + Electricity_{cogen}} \quad \text{(C1)}$$

Where,

$Fuel_i$	=	Proportionate volume or mass of each type of fuel, by fuel type i, combusted by cogeneration unit to supply electricity or thermal energy to the CCS project (e.g., gallons/year or metric tons/year).
$Total\ Fuel_{cogen}$	=	Total volume or mass of each type of fuel, by fuel type i, combusted by the cogeneration unit supplying electricity or thermal energy to the CCS project (e.g., gallons /year or metric tons/year).
$Heat_{CCS}$	=	Quantity of thermal energy supplied to the CCS project by the cogeneration unit (MJ/year).
$Electricity_{CCS}$	=	Quantity of electricity supplied to the CCS by the cogeneration unit (MWh/year).
$Heat_{cogen}$	=	Total quantity of thermal energy generated by the cogeneration unit (MJ/year).
$Electricity_{cogen}$	=	Total quantity of electricity generated by the third party cogeneration unit (MWh/year).

(5) Chemical inputs:

a. Purchase receipts/invoices or flow meter readings whichever applicable.

Note: Stationary emissions factors in Tables A2 to A4 may be used only if they are not available in CA-GREET.

Table A2. Stationary Emission Factors for Fossil Fuel Combustion.[13]

Coal and Coke	**kg CO_2/ton**	**g CH_4/ton**	**g N_2O/ton**
Anthracite (coal)	2602	276	40
Bituminous (coal)	2325	274	40
Sub-bituminous (coal)	1676	190	28
Lignite	1389	156	23
Mixed (commercial)	2016	235	34
Mixed (electric power sector)	1885	217	32
Mixed (industrial sector)	2468	289	42
Mixed (commercial)	2116	246	36
Coal Coke	2819	273	40
Fossil-derived Fuels (solid)	**kg CO_2/ton**	**g CH_4/ton**	**g N_2O/ton**
Municipal Solid Waste	902	318	42
Petroleum Coke (Solid)	3072	960	126
Plastics	2850	1216	160
Tires	2407	896	118
Fossil-derived Fuels (gaseous)	**kg CO_2/scf**	**g CH_4/scf**	**g N_2O/scf**
Blast Furnace Gas	0.02524	0.000002	0.000009
Coke Oven Gas	0.02806	0.000288	0.00006
Fuel Gas	0.08189	0.004164	0.000833
Propane Gas	0.15463	0.000055	0.000252

Note: Ton refers to short ton. While using Table A1 to A3, CO and VOC emissions may need to be estimated if possible.

[13] US EPA. Direct Emissions from Stationary Combustion Sources. (2016). Available at https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

Table A3. Stationary Emission Factors for Petroleum Fuel Combustion.[13]

Petroleum Products	kg CO_2/gal	g CH_4/gal	g N_2O/gal
Asphalt and Road Oil	11.91	0.47	0.09
Aviation Gasoline	8.31	0.36	0.07
Butane	6.67	0.31	0.06
Butylene	7.22	0.32	0.06
Crude Oil	10.29	0.41	0.08
Distillate Fuel Oil No .1	10.18	0.42	0.08
Distillate Fuel Oil No .2	10.21	0.41	0.08
Distillate Fuel Oil No. 4	10.96	0.44	0.09
Ethane	4.05	0.2	0.04
Ethylene	3.83	0.17	0.03
Heavy Gas Oils	11.09	0.44	0.09
Isobutane	6.43	0.3	0.06
Isobutylene	7.09	0.31	0.06
Kerosene	10.15	0.41	0.08
Kerosene-Type Jet Fuel	9.75	0.41	0.08
Liquefied Petroleum Gases (LPG)	5.68	0.28	0.06
Lubricants	10.69	0.43	0.09
Motor Gasoline	8.78	0.38	0.08
Naphtha (<401 deg F)	8.5	0.38	0.08
Natural Gasoline	7.36	0.33	0.07
Other Oil (>401 deg F)	10.59	0.42	0.08
Pentanes Plus	7.7	0.33	0.07
Petrochemical Feedstocks	8.88	0.38	0.08
Petroleum Coke	14.64	0.43	0.09
Propane	5.72	0.27	0.05
Propylene	6.17	0.27	0.05
Residual Fuel Oil No. 5	10.21	0.42	0.08
Residual Fuel Oil No. 6	11.27	0.45	0.09
Special Naphtha	9.04	0.38	0.08
Unfinished Oils	10.36	0.42	0.08
Used Oil	10.21	0.41	0.08

Table A4. Stationary Emission Factors for Petroleum Fuel Combustion.[13]

Biomass-Derived Fuels (Solid)	kg CO_2/ton	g CH_4/ton	g N_2O/ton
Agricultural Byproducts	975	264	35
Peat	895	256	34
Solid Byproducts	1096	332	44
Wood and Wood Residuals	1640	126	63
Biomass -Derived Fuels (gaseous)	**kg CO_2/scf**	**g CH_4/scf**	**g N_2O/scf**
Landfill Gas	0.025254	0.001552	0.000306
Other Biomass Gases	0.034106	0.002096	0.000413
Biomass Fuels (liquid)	**kg CO_2/gal**	**g CH_4/gal**	**g N_2O/gal**
Biodiesel (100%)	9.45	0.14	0.01
Ethanol (100%)	5.75	0.09	0.01
Rendered Animal Fat	8.88	0.14	0.01
Vegetable Oil	9.79	0.13	0.01
Biomass Fuels (Kraft Pulping Liquor by Wood Furnish)	**kg CO_2/MMbtu**	**g CH_4/MMbtu**	**g N_2O/MMbtu**
North American Softwood	94.4	1.9	0.42
North American Hardwood	93.7	1.9	0.42
Bagasse	95.5	1.9	0.42
Bamboo	93.7	1.9	0.42
Straw	95.1	1.9	0.42

Table A5. Default Emission Factors for Onshore Petroleum and Natural Gas Production.[12]

Onshore Petroleum and Natural Gas Production	Emission Factor (scf/hour/component)
Western US Population Emission Factors for all Components, Gas Service[a]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents[b]	1.39
High Continuous Bleed Pneumatic Device Vents[b]	37.3
Intermittent Bleed Pneumatic Device Vents[b]	13.5
Pneumatic pumps[c]	13.3
Population Emission Factors – All Components, Light Crude Service[d]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-Ended Line	0.05
Pump	0.01
Other[e]	0.30
Population Emission Factors – All Components, Heavy Crude Service[f]	
Valve	0.0005
Flange	0.0009
Connector (Other)	0.0003
Open-Ended Line	0.006
Other[5]	0.003

[a] For multi-phase flow that includes gas, use the gas service emission factors.
[b] Emission factor is in units of “scf/hour/device.”
[c] Emission Factor is in units of “scf/hour/pump.”
[d] Hydrocarbon liquids greater than or equal to 20°API are considered “light crude.”
[e] “Other” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[f] Hydrocarbon liquids less than 20°API are considered “heavy crude.”

Table A6. Default Average Component Counts for Major Crude Oil Production Equipment.[12]

Major Equipment	Valves	Flanges	Connectors	Open-Ended Lines	Other Components
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-Treater	8	12	20	0	0
Header	5	10	4	0	0

Table A7. Default Average Component Counts for Major Onshore Natural Gas Production Equipment.[12]

Major Equipment	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/Piping	14	51	1	1
Compressors	73	179	3	4
In-Line Heaters	14	65	2	1
Dehydrators	24	90	2	2

APPENDIX E

EMISSIONS FROM CO_2 ENTRAINED IN PRODUCED OIL AND GAS

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Appendix E. Emissions from CO_2 Entrained in Produced Oil and Gas

Equation D1: Annual CO_2 Fugitive Emissions Entrained in Produced Oil and Gas[14]

$$CO_{2_{entrained}} = (V_{gas} \times \%CO_{2_{gas}} \times \rho CO_2 \times 0.001) + (M_{water} \times F_{CO2-water}) + (M_{oil} \times F_{CO2-oil}) \quad \text{(E1)}$$

Where:

$CO_{2_{entrained}}$	=	Emissions or other losses of CO_2 entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO_2 for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product (MT CO_2/year).
V_{gas}	=	Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected into, that is sold to third parties or input into a natural gas pipeline in year y (m^3 /year), measured at standard conditions.
ρCO_2	=	Density of CO_2 at standard conditions (1.899 kg/m^3 or 0.0538 kg/ft^3).
$\%CO_{2_{gas}}$	=	% CO_2 in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y (% volume).
M_{water}	=	Mass of water produced from the formation that CO_2 is being injected into, that is disposed of or otherwise not re-injected back into the formation (MT/year).
$F_{CO2-water}$	=	Mass fraction of CO_2 in the water produced from the formation.
M_{oil}	=	Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into (MT/year).
$F_{CO2-oil}$	=	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation (MT/year).

[14] The American Carbon Registry "Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects," Version 1 (2015). Available at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/carbon-capture-and-storage-in-oil-and-gas-reservoirs/acr-ccs-methodology-v1-0-final.pdf.