

REQUIREMENTS FOR CALIFORNIA UNDERGROUND GAS STORAGE PROJECTS

TEXT OF PROPOSED REGULATIONS

CALIFORNIA CODE OF REGULATIONS, TITLE 14 CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

Article 3. Requirements

DELETE SECTION 1724.9:

~~1724.9 Gas Storage Projects~~

~~—The data required by the Division prior to approval of a gas storage project include all applicable items listed in Section 1724.7(a) through (e), and the following, where applicable:~~

- ~~—(a) Characteristics of the cap rock, such as areal extent, average thickness, and threshold pressure.~~
- ~~—(b) Oil and gas reserves of storage zones prior to start of injection, including calculations.~~
- ~~—(c) List of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.~~
- ~~—(d) Proposed waste water disposal method.~~

ADOPT NEW ARTICLE 4 WITH SECTIONS 1726, 1726.1, 1726.2, 1726.3, 1726.3.1, 1726.4, 1726.4.1, 1726.4.2, 1726.5, 1726.6, 1726.7, 1726.8, 1726.9, AND 1726.10:

Article 4. Requirements for Underground Gas Storage Projects

1726. Purpose, Scope, and Applicability.

The purpose of this article is to set forth regulations governing underground gas storage projects and gas storage wells. This article applies to underground gas storage projects and gas storage wells in existence prior to the effective date of this article, as well as new underground gas storage projects and gas storage wells. Underground gas storage projects and gas storage wells are not subject to the requirements of Sections 1724.6 through 1724.10.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.1. Definitions.

(a) The following definitions are applicable to this article:

(1) "Area of review" means the three-dimensional extent of the reservoir used for underground gas storage and surrounding areas that may be subject to its influence. The area of review is delineated by the geologic extent of the reservoir such as impervious rock, structural closure, decrease or loss of porosity and permeability, or hydrodynamic forces in a three dimensional image.

(2) "Caprock" means the rock layer or layers at the upper boundary of the storage reservoir acting as the primary barrier preventing upward migration of fluids.

(3) "Fluid" means liquid or gas.

(4) "Gas storage well" means an active or idle well used primarily to inject or withdraw gas from an underground storage project.

(5) "Reservoir" means the hydrocarbon reservoir that is being used to store natural gas in an underground gas storage project. The entire depth interval of a reservoir from the shallowest to the deepest depth can be subdivided into one or more depth intervals, which are referred to in this article as "zones".

(6) "Underground gas storage project" means a project for the injection and withdrawal of natural gas into an underground reservoir for the purpose of storage. An underground gas storage project includes the reservoir used for storage, the confining caprock, gas storage wells, observation wells, and any other wells approved for use in the project. A gas storage project also includes the wellheads and, to the extent that they are subject to regulation by the Division, attendant facilities, and other appurtenances.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3220 and 3403.5 Public Resources Code.

1726.2. Approval of Underground Gas Storage Projects.

(a) A Project Approval Letter shall be obtained from the Division before any injection occurs as part of an underground gas storage project. The Project Approval Letter shall specify the location and nature of the underground gas storage project, as well as the conditions of the Division's approval. Changes to the operational parameters of an underground gas storage project are subject to approval by the Division and shall be noted in either an addendum to the Project Approval Letter or a revised Project Approval Letter. Underground gas storage project operations shall not occur or continue unless consistent with the terms and conditions of a current Project Approval Letter.

(b) The Division will review underground gas storage projects periodically, but not less than once every three years, to verify adherence to the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letter to ensure that they effectively prevent damage to life, health, property, and natural resources. Project Approval Letters are subject to suspension, modification, or rescission by the Division.

(c) If the Division determines that operation of an underground gas storage project is inconsistent with the terms and conditions of a current Project Approval Letter, or otherwise poses a threat to life, health, property, or natural resources, then upon written notice from the Division specified operations shall cease immediately, or as soon as it is safe to do so.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3220 and 3403.5 Public Resources Code.

1726.3. Risk Management Plans.

(a) For each underground gas storage project, the operator shall submit a project-specific Risk Management Plan to the Division for review and approval. The Risk Management Plan shall demonstrate to the Division's satisfaction that stored gas will be confined to the approved zone(s) of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources. In accordance with subdivision (b), the Risk Management Plan shall evaluate threats and hazards associated with operation of the underground gas storage project and identify prevention protocols that effectively address those threats and hazards. The Risk Management Plan shall also specify a schedule for submitting updates to the risk assessment and prevention protocols to the Division. The Division may, in its discretion, require additional data, additional risk assessment, or modification of prevention protocols. The Division will review the Risk Management Plan periodically, but not less than once every three years. Risk assessment and prevention protocols in the Risk Management Plan shall be consistent with and additional to any other existing requirements.

(b) The Risk Management Plan shall include a description of the methodology employed to conduct the risk assessment and identify prevention protocols, with references to any third-party guidance followed in developing the methodology. The methodology shall include at least the following:

- (1) Identification of potential threats and hazards associated with operation of the underground gas storage project;
- (2) Evaluation of probability of threats, hazards, and consequences related to the events;
- (3) Identification of possible prevention protocols to reduce or monitor risks, including evaluation of the efficacy and cost-effectiveness of the prevention protocols;
- (4) Selection and implementation of prevention protocols;
- (5) Documentation of the risk assessment process, including description of the basis for selection of prevention protocols;

(6) Data feedback and validation throughout the risk assessment process; and
(7) Regular, periodic risk assessment reviews to update information and evaluate the effectiveness of prevention protocols employed, which shall occur not less than once every three years and in response to changed conditions or new information.

(c) In addition to the contents required in subdivision (b), all Risk Management Plans shall include at least the following risk assessment and prevention protocols:

(1) Well construction and design standards, consistent with the requirements of Section 1726.5 and including specification of the life expectancy of individual mechanical well barrier elements. If the operator has gas storage wells that do not conform with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan for either bringing the nonconforming wells into compliance or plugging and abandoning the wells in accordance with Public Resources Code section 3208. The work plan shall include prevention protocols for monitoring and testing each well that is not yet in compliance with the requirements of Section 1726 so as to mitigate risks associated with the well to the extent feasible.

(2) For each gas storage well, evaluation of whether employment of surface and/or subsurface automatic or remote-actuated safety valves is appropriate based on consideration of at least the following:

(A) The well's distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people may assemble such as campgrounds, recreational areas, or playgrounds;

(B) Gas composition, total fluid flow, and maximum flow potential;

(C) The distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;

(D) The risks created by installation and servicing requirements of safety valves;

(E) The risks to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;

(F) Proximity to environmentally or culturally sensitive areas;

(G) Alternative protection measures which could be afforded by barricades or distance or other measures;

(H) Age of well;

(I) The risks of well sabotage;

(J) The current and predicted development of the surrounding area as reflected in the local general pl, topography and regional drainage systems and environmental considerations;

(K) Topography and local wind patterns; and

(L) Evaluation of geologic hazards such as seismicity, active faults, landslides, subsidence, and potential for tsunamis.

(3) A schedule for verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage. The mechanical integrity testing protocols for gas storage wells shall, at a minimum, adhere to the requirements of Section 1726.6.

(4) Corrosion monitoring and evaluation including at least the following:

- (A) Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;
 - (B) Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;
 - (C) Corrosion potential of annular and packer fluid;
 - (D) Corrosion potential of current flows associated with cathodic protection systems;
 - (E) Corrosion potential of all formation fluids, including fluids in formations above the storage zone; and
 - (F) Corrosion potential of uncemented casing.
- (5) Ongoing monitoring of casing pressure changes at the wellheads of gas storage wells, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures, and analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.
- (6) Monitoring protocols in accordance with the requirements of Section 1726.7.
- (7) Ongoing verification and demonstration of the integrity of the reservoir including demonstration that reservoir integrity will not be adversely impacted by operating conditions.
- (8) Analysis and risk assessment of hazards associated with the formation of hydrates, and scale from the well stream under various pressure, temperature, and flow rates, including those beyond expected operating parameters.
- (9) Analysis and risk assessment of geologic hazards including, and not limited to seismicity, faults, subsidence, inundation by tsunamis, sea level rise, and floods.
- (10) Analysis and risk assessment of hazards associated with the potential for fire.
- (11) If observation wells are employed, identification and documentation of baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level.
- (12) Prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat.
- (13) Safety training for on-site personnel.
- (14) An equipment maintenance program that includes training and proactive replacement of equipment at risk of failure so as to ensure safe operation.
- (15) An emergency response plan that accounts for the threats and hazards identified in the Risk Management Plan and that complies with the requirements of Section 1726.9.
- (16) Requests for notice from land use agencies of local land use decisions that could affect the Risk Management Plan, and providing notification to the Division of significant pending land use decisions.
- (d) The operator shall adhere to the risk mitigation protocols detailed in its Risk Management Plan unless variance has been approved by the Division in writing.
- (e) The Division will provide completed Risk Management Plans and significant updates to the Risk Management Plans to the California Public Utilities Commission and post them on the Division's public internet website. If any part of a Risk Management Plan is subject to

confidential treatment, then the Division will segregate the confidential records and only provide them if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.3.1 Emergency Response Plan.

(a) The operator of an underground gas storage project shall have an emergency response plan approved by the Division and ready for immediate implementation. The emergency response plan shall specify a schedule for carrying out drills to validate the plan. The drills shall address the readiness of personnel and their interaction with equipment including required third party service providers and their current contact information. The operators shall provide local first responders at least 30 days to review and provide input on the emergency response plan.

(b) The emergency response plan shall at a minimum address the following scenarios:

- (1) Collisions involving well heads;
- (2) Well fires and blowouts;
- (3) Hazardous material spills;
- (4) Equipment failures;
- (5) Natural disasters/emergencies;
- (6) Leaks and well failures;
- (7) Medical emergencies; and
- (8) Explosions.

(c) The emergency response plan shall at a minimum include all of the following:

(1) Written actions plans establishing assigned authority to the appropriate qualified person(s) at a facility for initiating effective emergency response and control;

(2) Accident-response measures that outline response activities, leakage mitigation approaches, and well control processes for well failure and full blowout scenarios;

(3) Prepositioning, as feasible, and identification of materials and personnel necessary to respond to leaks, including materials and equipment to respond to and stop the leak itself as well as to protect public health.

(3) A schedule for regular drills, providing for an opportunity for involvement of the Division and local first responders, and providing an opportunity for surprise drills initiated by local first responders;

(4) A schedule for regular evaluation and update of the emergency response plan;

(5) Protocols for emergency reporting and response to appropriate government agencies;

(6) Specification of personnel roles and responsibilities;

(7) Internal and external communication protocol;

(8) Emergency contact information including area codes; and

(9) A protocol for public notice of a large, uncontrollable leak to any potentially impacted community, as defined in the risk management plan, if the leak cannot be controlled within 48 hours of discovery by the operator.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3183, 3184 and 3403.5 Public Resources Code.

1726.4. Underground Gas Storage Project Data Requirements.

(a) For all underground gas storage projects, the operator shall provide the Division with data, analysis, and interpretation that demonstrate to the Division's satisfaction that stored gas will be confined to the approved zone(s) of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources. The operator shall provide the data specified in this section and any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the proposed project. The data provided by the operator shall be to a level of detail and certainty satisfactory to the Division, and the operator shall ensure that required data is complete, current, and accurate, regardless of the date of approval of the gas storage project. The data submitted to the Division shall include at least the following:

(1) Oil and gas reserves of all proposed storage zones prior to start of injection, including calculations, to indicate the storage capacity of the reservoir being considered for gas storage.

(2) Description of existing or proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.

(3) Proposed produced water disposal method.

(4) Maximum and minimum reservoir pressure for the underground gas storage project and the data and calculations supporting the bases for the pressure limits. The pressure limits shall account for the following:

(A) The pressure required to inject fluids, particularly at total inventory, shall not exceed the design pressure limits of the reservoir, caprock, wells, well heads, piping, or associated facilities.

(B) The minimum reservoir pressure shall take into account the historic minimum operating pressure and reservoir geomechanical competency. The impacts of intended minimum reservoir pressure shall be accounted for as it relates to geomechanical stress and liquid influx.

(5) An engineering and geological study demonstrating that injected gas will not migrate out of the approved zone or zones, such as through another well, geologic structure, faults, fractures or fissures, or holes in casing. The study shall include, but is not limited to:

(A) Statement of primary purpose of the project.

(B) Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations.

(C) A comprehensive geologic characterization of the gas storage project including lithology of the storage zone or zones and sealing mechanisms as well as all formations encountered from surface to the deepest well in the project. The geologic characterization shall include any information that may be required to ensure injected or withdrawn gas does not have an adverse effect on the project or pose a threat to life, health, property or natural resources. The geologic characterization shall include potential pathways for gas migration and areas or formations where potential entrapment of migrated gas could occur. Information to accompany the geologic characterization shall include but is not limited to:

(i) Structure contour maps drawn on a geologic marker at or near the top of each gas storage zone in the project area, indicating faults and other lateral containment features.

(ii) Isopach map of each gas storage reservoir or subzone in the project area.

(iii) At least two geologic cross sections through at least four gas storage wells in the project area and the areas immediately adjacent.

(iv) Representative electric log to a depth below the deepest producing zone identifying all geologic units, formations, aquifers with groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, aquifers with groundwater that has 3,000 or less milligrams per liter of total dissolved solids content, oil or gas zones, and gas storage reservoirs.

(v) Additional information may be requested by the Division, and may include, but is not limited to: isopach, isoGOR, isoBAR, three-dimensional modeling, oil-water, gas-water, or oil-gas contact maps of the project, or other information which would delineate known features such as faults and fractures within the area of review for the underground gas storage project.

(D) Reservoir fluid data for each gas storage zone, such as oil gravity and viscosity, water quality, presence and concentrations of non-hydrocarbon components in the associated gas (e.g. hydrogen sulfide, helium, etc.), and specific gravity of gas.

(E) A map of the area of review showing the location and status of all wells within and adjacent to the boundary of the area of review. The wellbore path of directionally drilled wells shall be shown, with indication of the interval penetrating the gas storage zone(s) of the underground gas storage project.

(F) Casing diagrams, including all data specified in Section 1726.4.1, of all wells that are within the area of review and that are in the same or a deeper zone as the gas storage project, including directionally drilled wells that intersect the area of review in the same or deeper zone. The casing diagrams must demonstrate that the wells in the area will not be a potential conduit for gas to migrate outside of the approved zone of gas storage or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources. At a minimum, the casing diagrams must demonstrate that plugged and abandoned wells have cement 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, or the intended zone of injection.

(G) Identification of all wells within the area of review that are not in the same or a deeper zone as the underground gas storage project, including description of the total depth of the well and the estimated top of the gas storage reservoir below the well.

(H) Wells completed in or penetrating through the intended gas storage reservoir shall be identified and evaluated for containment assurance for the design of gas storage operation volumes, pressure, and flow rates. The operator should identify, and the Division confirm, wells which may require integrity testing or well logging in order to meet the integrity demonstration. The Division may select plugged and abandoned wells to be re-entered, examined, re-plugged and abandoned, or monitored to manage identified containment assurance issues prior to approval of gas storage operations.

(I) The planned or estimated well drilling and plugging and abandonment program to complete the project, showing all gas storage wells, plugged and abandoned wells, other wells related to the project, and unit boundaries.

(J) Maps of the locations of underground disposal horizons, mining, and other subsurface industrial activities not associated with oil and gas production or gas storage operations within the area of review, to the extent it is publicly available.

(6) A gas storage injection and withdrawal plan that includes at least the following:

(A) Maximum anticipated surface injection pressure and maximum anticipated daily rate of injection, by well.

(B) Monitoring system or method acceptable to the Division to be utilized to ensure the gas injected is confined to the intended approved zone(s) of injection.

(C) A wellhead monitoring system acceptable to the Division for the detection of leaks.

(D) A list of proposed cathodic protection measures where employed.

(E) A summary of the source and analysis of the gas injected, submitted to the Division on an annual basis.

(7) The name and API number of all gas storage wells and other wells that are part of the underground gas storage project.

(8) Any data that, in the judgment of the Division, are pertinent and necessary for the proper evaluation of the underground gas storage project.

(b) Updated data shall be provided to the Division if there are changes in operating conditions, such as gas plant or compressor changes, or if more accurate data become available, such as updated cross sections, new reservoir characteristics data, or new pressure flow modeling.

(c) All data filed with the Division under this section shall be submitted electronically, in a format acceptable to the Division. All maps, diagrams and exhibits shall be clearly labeled as to scale, north arrow, coordinate system, and purpose, and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

(d) Where it is infeasible to supply the data specified in subdivision (a), the Division may accept alternative data that demonstrate to the Division's satisfaction that injected gas will be confined to the approved reservoir or reservoirs of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources.

(e) The operator shall consult with the Division if the operator believes that there is a basis under state or federal law for confidential treatment of any data submitted to the Division. If the Division agrees that there is a basis for confidential treatment of data submitted, then the Division will take appropriate steps to maintain the confidentiality of that data.

(f) The Division will make all data received under this section available to the California Public Utilities Commission upon request. If the requested records are subject to confidential treatment, then the Division will only provide the records if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:

Note: Authority cited: Sections 3013, 3180 and 3106, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.4.1. Casing Diagrams.

(a) Casing diagrams submitted under Section 1726.4 shall adhere to the following requirements:

- (1) Casing diagrams shall at a minimum include all of the following data:
 - (A) Operator, 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 groundwater that has 3,000 or less milligrams per liter of total dissolved solids content;
 - (E) Base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content;
 - (F) Sizes, weights, grades, and connection types of casing and tubing;
 - (G) Details on associated equipment such as subsurface safety valves, packers, gas lift mandrels;
 - (H) Depths of shoes, stubs, and liner tops;
 - (I) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, patches, casing damage, top of junk or fish left in well, and any other feature that influences flow in the well or may compromise the mechanical integrity of the well;
 - (J) Hole size diameter and depth of drilled hole;
 - (K) Cement plugs inside casings, including top and bottom of cement plug, with method of determination;
 - (L) All cement fill behind casings, including top and bottom of cemented interval, with method of determination;
 - (M) Type and density of fluid between cement plugs;
 - (N) Depths and names of the formation(s), zone(s), and geologic markers penetrated by the well, including the top and bottom of the gas storage zone(s) and the top and bottom of the caprock;
 - (O) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job; and
 - (P) All of the information listed in this paragraph for all previous drilled or sidetracked well bores.

(2) Measured depth and true vertical depth shall be provided for all measurements required under subdivision (a)(1).

(3) For directionally drilled wells, a directional survey shall be provided with inclination, azimuth measurements, and surface location.

(4) Casing diagrams shall be submitted in an electronic format acceptable to the Division.

(5) For all wells to be used for gas injection and/or withdrawal, the casing diagram shall include the mechanical well barrier elements that comprise the primary and secondary barriers as specified in section 1726.5.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.4.2. Records Management.

(a) The operator of an underground gas storage project shall establish a Records Management Program to ensure documentation of essential information is created, maintained, protected, and retrievable when needed. The operator shall submit its Records Management Plan to the Division for review and approval.

(b) The Records Management Program shall identify all records related to evidence of conformity to the requirements in this article as essential, and these records shall be maintained for the lifetime of the project.

(c) The Records Management Program shall establish a filing and storage strategy that ensures records are accessible and protected against environmental damage. Records may exist in many different formats and shall be managed according to the format in which they are maintained. Records may be protected following a graded approach, commensurate with the value of the record and the cost to reproduce the information.

(d) The Records Management Program shall establish a process for tracking records throughout their entire information life cycle so that it is clear at all times where a record exists, which is the most current version of the record, and the history of change or modification of the record.

(e) The Records Management Program shall allow for prompt retrieval and production of records upon request from the Division.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3181, 3220 and 3403.5 Public Resources Code.

1726.5. Well Construction Requirements.

(a) Operators shall design, construct, and maintain gas storage wells to effectively ensure mechanical integrity under anticipated operating conditions for the underground gas storage project. The operator shall ensure that a single point of failure does not pose an immediate threat of loss of control of fluids and make certain that integrity concerns with a gas storage well are identified and addressed before they can become a threat to life, health, property, or natural resources.

(b) Operators can demonstrate that a gas storage well adheres to the performance standard in subdivision (a) by demonstrating all of the following:

(1) The well has been completed with both primary and secondary mechanical well barriers to isolate the storage gas within the storage reservoir and transfer storage gas from the surface into and out of the storage reservoir.

(A) The primary mechanical barrier is the barrier that is exposed to the withdrawal or injection flow stream. The primary mechanical barrier shall be able to withstand full operating pressure as demonstrated by periodic pressure testing and through annular pressure monitoring. An example of a well configuration that meets the minimum requirements for a primary mechanical barrier is a well configuration that includes:

- (i) A Christmas tree master valve;
- (ii) Tubing hanger with seals;
- (iii) Production tubing; and
- (iv) A production packer.

(B) The secondary mechanical barrier is not exposed to the withdrawal or injection flow stream under normal operations. The secondary mechanical barrier shall be able to withstand full operating pressure as demonstrated by periodic annular pressure testing and casing evaluation logs. In the event of a primary mechanical barrier failure, the secondary mechanical barrier shall be able to contain the leaking fluids until the primary mechanical barrier is re-established. An example of a well configuration that meets the minimum requirements for a secondary mechanical barrier is a well configuration that includes:

- (i) Wellhead components, including casing hanger and seal assembly; and
- (ii) Production Casing.

(2) Each string of casing is designed to safely contain the expected internal and external pressures and tensile loads.

(3) The surface casing is of sufficient size, weight, grade, competency, and depth to support subsequent drilling operations.

(4) The production casing is of sufficient size, weight, grade, competency, and depth to maintain the well integrity, and is compatible with fluid chemical composition. The production casing is designed to accommodate fluids on injection and withdrawal at the maximum expected pressures and velocities. The production casing is free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work are sealed to establish hydraulic isolation.

(5) Casing connections are appropriate for use in the well design and exceed the expected mechanical loads.

(6) The gas storage well is cemented so as to maintain the integrity of the storage zone(s) by providing isolation of the reservoir from communication with other sources of permeability or porosity through the wellbore. Isolation is accomplished by filling the annular space between the casing and formation with competent cement to create a seal so that communication of fluids from the storage zone or other zones of interest is prevented.

(7) The cementing operations used a cement slurry designed for the anticipated wellbore conditions. All casing was cemented in a manner that ensures proper distribution and bonding of cement in the annular spaces. Additionally, cementing operations meet or exceed the following requirements:

(A) Surface casing is cemented with sufficient cement to fill the annular space from the shoe to the surface to protect ground water.

(B) Intermediate and production casings, if not cemented to the surface, are cemented with sufficient cement to fill the annular space to at least 500 feet above the gas storage reservoir, oil and gas zones or anomalous pressure intervals and to at least 100 feet above the base of groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(8) Cement plugs provide for effective zonal isolation.

(9) Any remedial cement slurry and placement techniques are designed for the specific wellbore conditions, formations, and type of repairs.

(10) Cement bond log or evaluation acceptable to the Division is on file that indicates an adequate cement bond between the casing, cement and geologic formations. A competent cement bond extends across the caprock, and at least 100 feet above the gas storage reservoir.

(11) For wells equipped with tubing and packer, packer is set in cemented casing within caprock or at a location acceptable to the Division.

(c) If the operator does not demonstrate that a gas storage well meets the criteria of subdivision (b), then the operator shall demonstrate to the Division's satisfaction that an alternative method of well design and construction has been employed that effectively adheres to the performance standard of subdivision (a). The Division will determine on a case-by-case basis whether the operator has effectively demonstrated that a gas storage well that does not conform to the criteria in subdivision (b) meets the performance standard in subdivision (a).

(d) The requirements of this section are in addition to all other well construction requirements of this chapter.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3220 and 3403.5 Public Resources Code.

1726.6. Mechanical Integrity Testing.

(a) The operator shall, at a minimum, conduct the following mechanical integrity testing on each gas storage well and every other well that penetrates the gas storage reservoir of the operator's underground gas storage project, with the exception of wells that have been plugged and abandoned in accordance with Public Resources Code section 3208:

(1) A temperature and noise log shall be conducted at least annually to ensure integrity. All anomalies identified shall be immediately reported to the appropriate district office and explained to the Division's satisfaction. If the operator is unable to explain any anomaly to the Division's satisfaction, then the well shall not be used for injection or withdrawal without subsequent approval from the Division.

(2) A casing wall thickness inspection, employing such methods as magnetic flux and ultrasonic technologies, shall be performed at once least every 24 months to determine if there are possible issues with casing integrity. The results shall be compared against prior results and any other available data to determine the corrosion rate. If the casing wall thickness inspection indicate 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 utilizing Barlow's equation or another method acceptable to the Division, then the well shall be remediated and shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent casing wall thickness inspection schedule for a well if the operator demonstrates to the Division's satisfaction that the well's corrosion rate is low enough that biennial inspection is not necessary.

(3) A pressure test of the production casing shall be conducted at least once every 24 months. If injection in the gas storage well is through tubing and packer, then the pressure test shall be of the casing-tubing annulus of the well. Pressure tests shall be conducted at a pressure at least as high as 115 percent of the maximum operating pressure. Pressure testing shall be conducted with liquid unless the Division approves pressure testing with gas. The pressure test shall be for one hour. A pressure test is successful if during the final thirty minutes of continuous pressure testing the pressure gauge does not show more than a 10 percent overall decline in pressure from the initial pressure and if during the final five minutes of continuous pressure testing the pressure gauge does not show more than an average of 0.075 percent decrease in pressure per minute. The Division may modify the testing parameters on a case-by-case basis if, in the Division's judgement, the modification is necessary to ensure an effective test of the integrity of the casing. If a pressure test is not successful, then the well shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent pressure testing schedule for a well if the operator demonstrates to the Division's satisfaction that other measures to ensure the integrity of the well warrant less frequent pressure testing.

(b) A newly constructed gas storage well, or a reworked gas storage well that has had its existing production casing modified from its previous condition during rework activities, shall be tested as per subdivision (a).

(c) The Division may require additional testing as needed to demonstrate the integrity of the well.

(d) The appropriate district office shall be notified at least 48 hours before performing mechanical integrity testing so that Division staff may have an opportunity to witness the testing. All mechanical integrity testing shall be documented and copies of test results shall be submitted to the Division in an electronic format within 30 days.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.7. Monitoring Requirements.

(a) The operator shall monitor for the presence of gas in all annuli by measuring and recording annular pressure at least once a day. The operator shall evaluate any anomalous annular gas occurrence and immediately report it to the Division. This requirement may be met by employment of a real-time data gathering system, such as Supervisory Control and Data Acquisition.

(b) The operator shall monitor the material balance behavior of an underground gas storage project's storage reservoir relative to the original design and expected reservoir behavior. The operator shall evaluate and correct unexpected conditions detected during monitoring in order to avoid an incident or loss. Monitoring frequency should be based on factors such as reservoir and well fluid loss potential and flow potential, as outlined in the Risk Management Plan. The operator shall submit material balance support data to the Division at least once a year, or upon request by the Division. Acceptable reservoir integrity monitoring and analysis methods include any of the following, or an equally effective method approved by the Division:

(1) Monitoring average reservoir pressure versus inventory and comparing that to expected conditions in order to allow for the discovery and correction of any anomalies or unexpected conditions. Liquid level shall be taken into account when utilizing observation wells. Semiannual field shut-in tests, usually conducted at the point of seasonally high and low inventories, shall be conducted for inventory verification.

(2) Installation and monitoring of strategically located observation wells in the vicinity of spill points, within an aquifer, and above the caprock in potential collector formations to detect the presence or movement of gas using methods which can include review of fluid level records, well pressures, geophysical logging, gas composition or other tools and methods deemed appropriate.

(3) Monitoring offset hydrocarbon production or disposal operations for unexplained flow or pressure changes. The monitoring shall include operations in zones above and below the storage reservoir as well as laterally offset locations.

(4) Conducting subsurface correlation and gas identification logs such as gamma ray-neutron logs to confirm the location of gas being injected into the intended storage reservoir, as needed.

(c) The operator shall immediately report to the Division any instance of a surface or cellar gas release of any size, in any location within the area of review of the underground gas storage project. The operator shall chemically fingerprint the gas from such a release within 48 hours of detection, and the operator shall provide the results of the gas analysis to the Division as soon as they are available.

(d) The operator of an underground gas storage project shall employ a real-time data gathering system, such as Supervisory Control and Data Acquisition, by January 1, 2020. At a minimum, the real-time data gathering system shall be deployed and utilized in accordance with the following requirements:

(1) The real-time data gathering system shall include pressure sensors for every casing annulus and transmitted to an operations monitoring center.

(2) The real-time data gathering system shall have alarms set for each annulus to monitor for pressure indicative of potential leaks or potential migration of gas. The alarms shall alert the operations monitoring center if pressure exceeds preconfigured set points. For tubing, the alarm set point shall not be higher than the maximum allowable surface pressure. For annuli between production casing and tubing, the alarm set point shall be determined based on annular fluid, the initial pressure when the packer was set, and operational configuration. For strings without any anticipated surface pressure, such as surface or intermediate casings, the alarm set point shall not be higher than 100 psi.

(3) If sustained casing pressure above 100 psi is believed to be caused by shallow gas or other fluid migration, then the operator shall do the following:

(A) The operator shall first bleed off annular pressure and track pressure and time for the well to build-up pressure back to equilibrium pressure.

(B) Next, the operator shall sample the fluids building up in the annulus and confirm that the accumulation is not due to migration of storage gas by performing chemical finger printing or other diagnostic tests approved by the division.

(C) If the diagnostic testing under paragraphs (A) and (B) confirm that the pressure build up is not due to migration of storage gas, the operator shall propose an alarm set point to the Division that is no greater than 100 psi above the equilibrium pressure, unless such pressure would pose a risk to casing integrity. The operator's proposal shall at a minimum address the results from the diagnostic testing, the effect of the proposed alarm set point pressure on casing integrity, the likely source of pressure and fluid composition determined from chemical fingerprinting, and a long term monitoring plan. The alarm set point shall not be increased until it has been approved by the Division.

(D) If the equilibrium pressure plus 100 psi would pose a risk to the integrity of the casing, then the operator shall develop and implement a plan to address the situation, subject to the Division's approval.

(E) If the testing under paragraphs (A) and (B) indicate that the pressure build up is due to migration of storage gas, then the operator shall conduct further testing to determine the pathway of migration and take remedial action as needed in accordance with a plan approved by the Division.

(e) The operator of an underground gas storage project shall conduct a Neutron Gamma Ray, or equivalent gas detection log approved by the Division, on each gas storage well at least annually to detect gas indications behind casing. The operator shall provide the results to the Division, as well as a year-to-year comparison with the prior results noting any changes in the indicated gas behind the casing. If the year-to-year comparison indicates increasing gas accumulations behind casing, then the operator shall submit a detailed remediation plan for the Division's approval.

(f) The operator of an underground gas storage project shall adhere to an inspection and leak detection protocol that has been approved by the Division. The protocol shall include inspection of the wellhead assembly and attached pipelines for each of the gas storage wells used in association with the underground gas storage project, and the surrounding area within a 100-foot radius of the wellhead of each of the wells used in an underground gas storage project. The inspection protocol shall provide for inspection at least once a day, employing effective gas leak detection technology such as infrared imaging, and shall provide for immediately reporting leaks to the Division. The operator's selection and usage of gas leak detection technology shall take into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology. The Division will consult with the California Air Resources Board when reviewing an inspection and leak detection protocol submitted under this subdivision. The requirements of this subdivision shall cease to apply to an underground gas storage project if the California Air Resources Board approves a monitoring plan under its regulations for that facility.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.8. Inspection, Testing, and Maintenance of Wellheads and Valves.

(a) Where installed, the operator of an underground gas storage project shall test all surface and subsurface safety valve systems to ensure ability to hold anticipated pressure at least every six months. The tests shall be conducted in accordance with American Petroleum Institute Recommended Practice 14B (6th Edition, September 2015), or equivalent, to confirm operational integrity. The appropriate district office shall be notified at least 48 hours before performing testing so that Division staff may witness the operations, and documentation of the testing shall be maintained and available for Division review. A closed storage well safety valve system shall be re-opened with operator staff at the site of the valve to ensure the absence of any unforeseen issues. Within 90 days of finding that a surface or subsurface safety valve is inoperable, the operator shall either repair the safety valve or temporarily plug the well. An appropriate alternative timeframe for testing a valve or addressing an inoperable surface or subsurface safety valve may be required by the Division.

(b) At least annually, the operator of an underground gas storage project shall test the master valve and wellhead pipeline isolation valve for proper function and verify ability to isolate the well.

(c) The operator shall equip gas storage wells with valves to provide isolation of the wells from the pipeline system and to allow for entry into the wells.

(d) The operator shall equip all ports on the wellhead assembly above the casing bowl of gas storage wells with valves, blind flanges, or similar equipment.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.

1726.9. Well Leak Reporting.

(a) For the purposes of this section, and for the purposes of Public Resources Code sections 3183 and 3184, “reportable leak” means:

(1) A leak from a gas storage well that is above 50,000 parts per million by volume total hydrocarbons, as measured using methodology that the operator has demonstrated will provide consistent and reliable measurements, such as US EPA Reference Method 21;

(2) A leak from a gas storage well that is above 10,000 parts per million by volume total hydrocarbons, as measured using methodology that the operator has demonstrated will provide consistent and reliable measurements, such as US EPA Reference Method 21, for more than five days; or

(3) Any leak that poses a significant present or potential hazard to public health and safety, property, or to the environment.

(b) If a gas storage well has a reportable leak, then the operator shall immediately inform the Division.

(c) The requirements of this section are in addition to, and do not supersede, any other requirements for reporting or responding to leaks from a gas storage well.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3183, 3184, 3220 and 3403.5 Public Resources Code.

1726.10. Requirements for Decommissioning.

(a) If an operator intends to discontinue an underground gas storage project, then the operator shall submit a Decommissioning Plan to the Division. The Decommissioning Plan is subject to the Division’s review and approval and shall ensure that stored gas will continue be confined to the approved zone(s) of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources. At a minimum, the Decommissioning Plan shall address all of the following:

- (1) Identification of the intended use of the wells and facilities after decommissioning, including a plan for obtaining requisite approvals for the use.
- (2) A plan for managing remaining gas in the underground gas storage reservoir.
- (3) A plan for repurposing or decommissioning all wells and facilities associated with the underground gas storage project.
- (4) Consultation with the Public Utilities Commission.
- (b) An underground gas storage project is subject to the requirements of this article until the Division has approved a Decommissioning Plan and the Division has certified that the operator has completed all steps required under the Decommissioning Plan.

AUTHORITY:

Note: Authority cited: Sections 3013, 3106 and 3180, Public Resources Code. Reference: Section 3106, 3180, 3181, 3220 and 3403.5 Public Resources Code.