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Subject: Amended Gas Storage Discussion Draft

Dear Mr. Harris,

The Environmental Defense Fund (EDF) appreciates the opportunity to comment on the Division's proposals for updating its gas storage regulations. California has a unique opportunity to establish strong safety and environmental standards for gas storage facilities that not only would protect Californian communities but also provide insight for other federal and state jurisdictions considering revisions to their gas storage regulatory frameworks. California can set the example for the rest of the country, as it so often has on critical environmental issues.

As a general matter, the effectiveness of the program will come down to implementation, particularly in the approval process of the risk management plans and the decisions to grant exceptions to the rule's prescriptive elements. EDF trusts that the Division of Oil, Gas, and Geothermal Resources (DOGGR) will use all the resources at its disposal to be intelligent, cautious, deliberative, and transparent as it customizes the regulatory program of the state gas storage facilities for their particular circumstances and risks.

The discussion draft itself has many commendable provisions, and is evidence of hard and thoughtful work on the part of DOGGR staff and leadership. In these comments, EDF will provide detailed thoughts and recommendations on the following topics:

- Risk management planning
- Variances
- Buffer zones / observation wells
- Well construction
- Subsurface safety valve requirements
- Integrity testing protocols
- Annular pressure monitoring
- Surface leak detection
- Tracking metrics
- Plugging & Abandonment and Temporary Abandonment

The remainder of today's comments is divided into four parts: (1) a description of revisions to the discussion draft we are suggesting at this time and why these changes are critical; (2) a short list of smaller edits; (3) a redline incorporating the amendments we are suggesting today; and (4) appendices containing redlines associated with the rulemaking and other supporting documentation.

<u>(1) In order to improve the efficiency and effectiveness of its gas storage regulations, the Division should consider the following:</u>

Risk management plan: Gas storage is amenable to regulation in part through site-specific risk management planning, which develops risk controls tailored to the particular circumstances of each facility. This concept is central to the API recommended practices on gas storage, and in conjunction with prescriptive and performance-based regulation, is an appropriate component of a balanced regulatory approach for gas storage.

EDF is especially supportive of DOGGR's intention to review and approve of Risk Management Plans prior to their implementation. This is essential to ensuring that the plans are consistent with and additional to DOGGR requirements and that the plans have covered all of the factors articulated in the proposed rule and are tailored to the particular storage facility project.

While the proposed rule calls for the initial plans to be reviewed and approved, it does not specify such an arrangement for updates of the plans. Risks and risk control options change over time. Operators should be required to annually review whether new risks or risk control options justify an update to the plan, and if not, to certify as such with DOGGR. If they do, operators should update and submit a revised plan. Operators should in any case submit revised plans every five years at a minimum. Further, all updates should be reviewed and approved by DOGGR prior to implementation.

In order to help ensure the quality of the risk management plans, DOGGR should require Professional Engineer certification as part of the plan proposal submission (note that emergency response plans should also be certified by a competent professional).

An essential component of the oversight of risk management planning is the desired level of risk reduction achieved by implementing the plan. But the proposed rules do not articulate a standard (neither, it should be noted, do API's recommended practices). However, there are recognized and commonly used risk reduction metrics that DOGGR should consider employing.

In particular, DOGGR should adopt "As Low As Reasonably Practicable" (ALARP) as a target level for risk reduction. ALARP is used by the UK Health and Safety Executive, among others, to establish a heuristic for determining the adequacy of risk reduction.[1] Last year, the California Public Utilities Commission published a whitepaper contemplating the adoption of ALARP for utility rate cases, including for natural gas storage operators – EDF encourages DOGGR to read the paper and consult with CPUC officials on the implementation of ALARP in their shared domains.[2]

The point of doing this would be to publicly establish uniform guiding principles on how DOGGR will evaluate risk management proposals, which require making tradeoffs between harm reduced and

[1] See http://www.hse.gov.uk/risk/theory/alarpglance.htm
[2] See http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=8930

expense. While industry will propose tradeoffs it believes to be appropriate, it is ultimately the task of the regulator to establish an appropriate level of risk to society, and to then work with industry to achieve that risk level at an appropriate expense. Whether DOGGR adopts ALARP or another standard, it is incumbent upon DOGGR to articulate some standard on which it will base its decisions.

Variances: Throughout the proposed regulation, DOGGR leaves room for operators to propose alternative measures. This is appropriate, as a facility's particular circumstances may warrant a different approach than that prescriptively required by the agency, and it allows for regulations to be responsive to changes in technologies over time. But as above, the rule should articulate the standard by which such variances are approved. Some of the provisions in the proposed regulation suggest a standard, but not all do. The gist of the standard should be that the alternative approach is at least as effective and protective as the prescriptive approach provided in the regulation.

Further, DOGGR should include in each well's file a note articulating what variances have been granted and providing evidence that shows that the variance meets the appropriate standard.

Buffer zones / observation wells: Operators should be required to delineate a "buffer zone" around the gas storage projects. The buffer zone can be described as an area or interval outside the defined gas storage reservoir, horizontally and/or vertically, where non-storage drilling or subsurface operations are restricted to provide protection of the gas storage reservoir from encroachment and/or leakage. The concept of a buffer zone is discussed throughout API RP 1171.

The buffer zone is an appropriate area for the placement and monitoring of observation wells. The proposed rule addresses the use of observation wells in 1726.7(b)(2). Observation wells are an early detection and monitoring system that allows for pressure and fluid observations and changes. These wells can be placed within a buffer zone into the same geological formation as the gas storage reservoir allowing for the monitoring of gas storage reservoir integrity, while observation wells completed in the first porous and permeable zone directly above the gas storage reservoir within the field itself allow for early detection of reservoir integrity within the vertical limits of the existing gas storage field. When observation wells are used, they should be constructed and operated per California's well construction and other relevant rules of general applicability.

Well construction: The proposed regulations contain in section 1726.5 certain requirements pertaining to well construction. While EDF provides some redlines to this section (including increasing to 500 feet the required interval of cement above groundwater less than 3000 TDS for intermediate and production casing), our main comment is that the rule should incorporate by reference DOGGR's existing general well construction regulations at 1722.2, 1722.3, 1722.4, 1722.5, and 1722.6 where not superseded by specific provisions in the gas storage rule.

These rules go into much greater detail on basic well design issues than the well construction rules in the proposed regulations.

At the same time, these well construction rules of general applicability could use a refreshing, as EDF has mentioned in comments at DOGGR proceedings throughout the year. In particular, EDF provides recommended adjustments in redline (see Appendix 1) on the following topics:

Casing Program (1722.2):

- Requirement for hydrostatic testing of casing before run in well
- Consistency with API standards
- General language on centralization

Casing Requirements (1722.3):

- Requirement to pressure test casing prior to drill out in surface and intermediate casing strings
- Requirement to perform formation integrity tests (FIT) on surface and intermediate casing strings

Cementing (1722.4):

- General requirements – how pumped (plug method, API standards and minimum compressive strengths)
- Language on determination of inadequate cement coverage.

Blowout Prevention (1722.5)

- Consistency with API Standard
- Pressure capacity guidance

These edits represent only a sample of potential improvements that EDF would offer in a full well construction rulemaking, but EDF nevertheless recommends their adoption to improve well integrity until such time as DOGGR can commence a full rulemaking revision on the subject. The edits are consistent with recommendations found in the Model Regulatory Framework, a well integrity regulatory guide developed by EDF and Southwestern Energy. Similar provisions can be found in regulations in Texas, Ohio, and elsewhere.

An additional note about the use of tubing and packer: EDF considers the use of tubing and packer with a corrosion inhibited, fluid-filled annulus to be a leading practice on grounds that such a configuration provides an extra barrier of protection, enables enhanced pressure monitoring, and can relieve corrosion on casing (plus damaged tubing is easier to replace than damaged casing). EDF recognizes that in some cases the use of tubing and packer would lower injection/production rates enough to require the development of new wells, at considerable cost to industry, which may be passed along to ratepayers. Ongoing studies, including those under development by the Department of Energy, will provide a more scientific assessment of risk reduction from the use of tubing and packer. In the meantime, the bar for a variance from the use of tubing and packer should be high, and DOGGR should require considerable evidence from operators seeking such a variance that it is necessary and that the alternative well configuration is at least as protective of safety and the environment.

Subsurface safety valve requirements: These valves have garnered much attention among policymakers, industry, and the public alike. When it came out that Aliso Canyon SS-25 had a subsurface safety valve (SSSV) in the early 1970s, parts of which were subsequently removed a few years later, many immediately began to speculate that had the valve been present, it could have averted the disaster. At this time there is insufficient evidence to make that claim – we all await the findings of the various root cause analyses currently underway.

In the months following the accident, EDF learned that SSSVs are not a panacea (instead, the panacea is the large and multidimensional task of properly planning, constructing, operating, testing, maintaining, and decommissioning wells) and that the appropriateness of a SSSV depends on each well's architecture and condition.

DOGGR proposes to require wells to use a subsurface safety valve, but to allow operators to propose alternative safety measures to prevent releases. There are many ways to construct and maintain wells to prevent releases; these valves are one tool in that arsenal. However, operators should show convincingly that alternative methods, potentially including surface safety valves, will reduce the risk of a release by at least as much as the use of an SSSV. DOGGR should examine with close scrutiny arguments based on the economic impact that SSSVs will have on wells' ability to efficiently inject and produce gas.

Further, EDF notes that existing DOGGR rules already provide detailed rules concerning safety valves, in sections 1724.3 and 1724.4. That language should be incorporated by reference where it is not superseded by the new rules.

Integrity testing protocols: On-going testing of each gas storage well's internal and external well integrity is crucial to preventing future Aliso Canyon-type incidents. This means conducting the right test (there are many different types) on the right well (different well configurations are amenable to different types of tests) at the right time (every test has a different appropriate interval, and every well suffers degradation at different rates) and in the right way (improperly conducted tests can do more harm than conducting no test at all, by inculcating a false sense of security). This makes it very difficult to provide prescriptive standards for well integrity testing on gas storage wells.

As a general matter, operators should demonstrate internal and external mechanical integrity at intervals appropriate for each well's condition and operating parameters using properly conducted tests, all in consultation and with approval of DOGGR. Much of this can be accomplished through the risk management planning process. DOGGR has rightly relied on the National Labs to provide support on well integrity testing for Aliso Canyon wells, and has developed an expertise in determining which tests are right for which wells at which times. During the early period of implementing this new rule, while DOGGR and the industry establish well integrity baselines and determines appropriate testing schedules, DOGGR should err on the side of caution. In particular, EDF urges DOGGR to require operators to conduct a full suite of tests to provide baseline information about both new and converted wells prior to their placement into service.

One area where the rules could be improved is with the inclusion of specific testing protocols for some of the more standard tests, including pressure tests, cement evaluation logging, noise and temperature logging, and corrosion logging. DOGGR should consider adoption of industry standard practices and the development of regulatory pass/fail criteria. DOGGR itself proposed protocols for these tests in its Class II UIC rulemaking discussion draft earlier this year; EDF provided comments on those protocols, which are attached to these comments (see Appendix 2). EDF recommends that DOGGR either incorporate this language directly into the gas storage rule, or create a standalone section of general applicability that the gas storage rule references. EDF also provides a redline in several places calling for an appropriate repeat section (generally 100' to 200' interval) to be run to verify log data accuracy and made a part of the log presentation unless well conditions warrant otherwise.

DOGGR should also be sure to provide, for each test, a rationale for why the test is being required and what information is expected to be obtained from running the test. Many of these tests can reveal many different things about the state of a well's integrity, depending on how they are run and analyzed. For example, temperature and noise logs can either detect massive breaches in the casing (if run quickly) or fluid migration behind the casing (if run slowly). Identifying the rationale and the expectations for required tests will help ensure that the testing is properly tailored to well conditions and agency objectives.

Finally, EDF provides a recommendation for the circumstance when, with respect to the pressure testing requirement, the Division allows for a lower testing pressure if necessary to ensure that the testing does not compromise the mechanical integrity of the well. Provided that the test at the lower pressure successfully demonstrates mechanical integrity, the Division should by administrative order reduce accordingly the maximum operational pressure of the well. If a well cannot withstand to be tested at the existing maximum operating pressure, it should not be permitted to operate at that pressure.

Annular pressure monitoring: Regular observation and monitoring of annular pressures is one of the easiest and most effective ways to evaluate well integrity. DOGGR is right to require it, and is progressive in requiring the use of continuous monitoring with remote telemetry by 2020 (though the agency would do well to closely watch the evolution of the technology and its cost, and consider accelerating the rollout through requirement or incentive).

DOGGR should specify *which* annuli should be monitored – EDF proposes that *all* casing annuli be monitored. The costs of monitoring are small compared to the benefits of discovering an integrity problem.

Further, DOGGR can enhance the specificity of how operators should evaluate pressure variations and appropriate circumstances for reaction by incorporating by reference API's recently updated recommended practice on annular pressure management, API RP 90-2. This recommended practice provides detailed technical guidance on measuring pressure, determining normal pressure ranges, and decision trees for reacting to abnormal pressure readings.

Surface Leak Detection: Emissions monitoring at natural gas storage facilities remains an important area of future technological development and an area in which much technological development has already occurred. As identified by several technology providers at the March 2016 methane symposium sponsored by the California Air Resources Board, several options exist for performing continuous and non-continuous emissions monitoring capable of identifying leaks and initiating leak response efforts. Ranging from open path lasers, to infrared cameras, and traditional LEL monitors, low-cost high-performance emissions monitors can be placed at wellheads, along land services and at fence lines. Accordingly, the inclusion of atmospheric monitoring for leak detection is appropriate within this rulemaking, just as it is within the ongoing rulemaking at the California Air Resources Board for oil and gas production systems.

Of course, as future technological improvements are made, the storage rule should be able to be updated and adapt to changing conditions. For this reason, EDF supports the proposed rule's focus on having the Commission approve new technologies and working with the Air Board going forward.

Performance Metrics: Public trust in gas storage operations in California was deeply eroded by the Aliso Canyon incident. One way DOGGR can bolster trust and show that the industry is performing to its standards is by tracking key performance indicators, or metrics, that are uniform across facilities and over time. In Appendix 3, EDF provides potential metrics to use for gas storage facilities, based on the EPA's Underground Injection Control program's metrics. Implementing these metrics would require some enhanced reporting, but the payoff in public trust (and indeed in DOGGR's own internal and external assessments of industry performance) is well worth it in EDF's opinion.

Plugging: This topic is not directly addressed in the proposed rule, and DOGGR's existing plugging and abandonment (P&A) section at Sec. 1723 should be incorporated by reference. Much like the well construction rules of general applicability discussed above, DOGGR would do well to update its plugging and abandonment rules and temporary abandonment rules. EDF provides some redlines on both. For plugging and abandonment, issues include:

- Cementing requirements
- Wellbore condition prior to plugging
- Cement height above bridge plugs

The section on idle wells is sparse. EDF is aware that this topic is the subject of considerable legislative and ultimately regulatory effort at DOGGR. EDF provides the following thoughts:

- Wells taken out of service and placed under Temporary Abandonment (TA) for more than 90 days because of well integrity issues should be required to demonstrate integrity or temporarily sealed with a bottom mechanical plug that will serve as a barrier and isolate the gas storage reservoir in a manner that prevents gas migration through or into the wellbore.
- All idle wells or wells with Temporary Abandonment status should be required to undergo all applicable monitoring and testing required of active wells.

<u>(2) Smaller changes found within the redline:</u>

- Redefine cap rock as confining zone: confining zone would be a better term to use for this definition. Cap rock is geologic term used to describe the geologic formation directly above the hydrocarbon-producing reservoir that acts as a seal that trapped the oil and gas accumulation.
- Clarifications to Project Approval Letter: addition of wells should result in Project Approval Letter modification approved by Division, and adjustment to Project Approval Letters accomplished through administrative orders.
- Enhancement of Risk Management Plan considerations: note especially addition of configuration of well to subsection on age of well.
- Modifications to well construction requirements aside from those provided in separate redline in Appendix 1, including general clarifications, introduction of redundant master valves, and renaming some equipment to match industry standards.

- Additional wellhead requirements with respect to pressures, valves, and barriers.
- Emergency Response Plan: documentation of demonstration of competency with respect to training and drills. Note that EDF continues to study leading practices related to Emergency Response Planning and will provide more detailed comments on the topic during the formal rulemaking.

(3) Track changes version of the discussion draft:

See attached markup of discussion draft. It is worth noting that in addition to the items above, EDF has made a variety of other small edits for clarity throughout the document, for which we urge due consideration.

(4) Appendices

1: Redline of well construction rules of general applicability
2: Excerpt of EDF's comments on DOGGR UIC discussion draft focused on well integrity testing protocols
3: Gas storage well metrics
4: P&A and TA language

Thank you for this opportunity to comment on the discussion draft. EDF looks forward to working with the Division over the coming months as it more fully fleshes out a robust regulatory framework for natural gas storage. If you wish to follow up on any of the items discussed in this letter or attachments, please feel free to contact us by email at apeltz@edf.org, or by phone at 212-616-1212.

Respectfully submitted,

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REQUIREMENTS FOR CALIFORNIA UNDERGROUND GAS STORAGE PROJECTS

DISCUSSION DRAFT

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

Subchapter 1. Onshore Well Regulations

[SECTION 1724.9 IS DELETED]

NEW ARTICLE ADDED:

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. 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 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.1 Definitions.

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

(1) "As Low As Reasonably Practicable" (ALARP) means a systematic risk-informed decision framework used to decide whether risk mitigation is needed and, when it is needed, how much should be spent until the mitigation costs are deemed to be disproportionally excessive relative to the benefits.

~~(1)~~(2) "Area of review" means the volumetric vertical and horizontal extent of the reservoir used for underground gas storage and surrounding areas that may be subject to its influence. The area of review may be ~~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)~~(3) "Confining zone~~aprock~~" 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)~~(4) “Fluid” means liquid or gas.

~~(4)~~(5) “Gas storage well” means a well used to inject or withdraw gas from an underground gas storage project.

~~(5)~~(6) “Gas Storage Reservoir” means a ~~the~~ hydrocarbon reservoir that is being, or has been converted and 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”.

(7) “Underground gas storage project” means a project for the injection and withdrawal of natural gas into an underground hydrocarbon reservoir for the purpose of storage. An underground gas storage project includes the reservoir used for storage, the confining zones~~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.

(8) “Division” means the California Division of Oil, Gas, & Geothermal Resources.

(9) “Buffer zone” means a protective boundary established beyond the gas storage reservoir area of review to protect the integrity of the gas storage operations.

AUTHORITY:

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

1726.2 Approval of Underground Gas Storage Projects.

(b) A Project Approval Letter shall be obtained from the Division before any injection or withdrawal 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 or addition of new wells to ~~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.

(c) The Division will review underground gas storage projects 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. Ongoing approval of an underground gas storage project is at the Division’s discretion and a Project Approval Letter is subject to suspension, modification, or rescission by the Division by Administrative Order.

(d) 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 by Administrative Order from the Division specified operations shall cease immediately, or as soon as it is safe to do so.

AUTHORITY:

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

1726.3 Risk Management Plans.

~~(e)~~(a) For each underground gas storage project, the operator shall submit a Risk Management Plan to the Division for review and approval. The Risk Management Plan shall identify potential threats and hazards to well and reservoir integrity, as well as life, health, property, and natural resources; assess risks based on potential severity and estimated likelihood of occurrence of each threat; identify the preventive and monitoring processes employed to mitigate each risk identified as well as overall and integrated risks; and specify a process for periodic review and reassessment of the risk assessment and prevention protocols. The Risk Management Plan shall be designed to reduce risks to a level As Low As Reasonable Practicable (ALARP) in consultation with the Division. Risk assessment and prevention protocols shall be consistent with and additional to any other existing requirement in statute or regulation. The operator shall state and justify what method and guidance it has followed in preparing the risk assessment. The Risk Management Plan shall specify a schedule for submission of risk assessment results to the Division. Risk Management Plan submissions, annual certifications, and updates shall all be certified by an appropriate Professional Engineer of the State of California. All Risk Management Plans shall include at least the following risk assessment and prevention protocols:

(1) Well construction, cementing, and design standards, consistent with the requirements of Section 1726.5. If the operator has gas storage wells that are not in conformance with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan for either bringing the wells into conformance or phasing the wells out of use in a time frame acceptable to the Division.

(2) For each gas storage well, installation~~employment~~ as appropriate of surface and/or subsurface automatic or remote-actuated safety valves based on the following:

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

(B) Gas composition, operational pressures, 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 and configuration of well;

(I) The risks of well sabotage;

(J) The current and predicted development of the surrounding area, topography and regional drainage systems and environmental considerations; and

(K) Evaluation of geologic hazards such as seismicity, active faults, landslides, subsidence, and other potential force majeure issues~~potential for tsunamis~~.

(3) Ongoing verification and demonstration of the external and internal mechanical integrity of each well used in the underground gas storage project and any~~each~~ well that penetrates or is drilled through in~~intersects~~ the reservoir used for gas storage within the area of review. 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 the following:

(A) Evaluation of tubular and all casing 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 evaluation of gas storage wells including monitoring of all casing pressure changes at the wellhead, 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) Material balance monitoring in accordance with the requirements of Section 1726.7(b).

(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) Identification of potential threats and hazards associated with operation of the underground gas storage project including the following:

(A) Evaluation of likelihood of events and consequences related to the events;

(B) Determination of risk ranking to develop preventive and mitigating measures to monitor or reduce risk;

(C) Documentation of risk evaluation and description of the basis for selection of preventive and mitigating measures;

(D) Provision for data feedback and validation;

(E) Regular, periodic risk assessment reviews to update information and evaluate risk management effectiveness; and

(F) Analysis and risk assessment of geologic hazards including, and not limited to seismicity, faults, subsidence, and other force majeure issues~~inundation by tsunamis, sea level rise, and floods~~.

(G) Analysis and risk assessment of hazards associated with the potential for explosion and/or fire.

(9) If observation wells ~~are~~ are required and installed~~employed~~, monitoring shall include: identification and documentation of baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level and geological formation being utilized for

observation. Observation wells should be constructed and operated pursuant to [applicable DOGGR requirements].

(10) Consideration of potential for impacts to underground sources of drinking water (USDWs) and groundwater quality resulting from operations of the underground gas storage project.

(11) Prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat.

(12) 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.

(b) On an annual basis, the operator shall evaluate whether risks or risk control options justify an update to the Risk Management Plan, and either provide an update to the Division for approval, or certify that no update is necessary, per subdivision (a). In any case, the operator shall update and submit a revised Risk Management Plan to the Division at least every five years, per subdivision (a).

(c~~b~~) The Division will make completed Risk Management Plans and ~~significant~~ updates to the Risk Management Plans available to the California Public Utilities Commission. 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 and 3106, Public Resources Code. Reference: Section 3106, 3220 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 withdrawal 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 Division 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 and current, regardless of the date of approval of the gas storage project. The data submitted to the Division shall include, but is not limited to 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.

~~(3)~~(4) Demonstration of external and internal well integrity.

~~(4)~~(5) 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 and withdraw storage fluids, particularly at total inventory, shall not exceed the design pressure limits of the reservoir, c~~aprock~~onfining zones, well constructions~~s~~, well heads, surface 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)~~(6) An engineering and geological study demonstrating that injected gas will not migrate out of the approved zone or zones, such as through another well penetration, geologic structure, faults, fractures or fissures, or loss of integrity of the ~~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 and withdrawal zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present bottom-hole 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, identification of USDWs, flow zones, lost circulation zones, corrosive zones, and commercial hydrocarbon-producing reservoirs, and areas or formations where potential entrapment of migrated gas could occur. Information to accompany the geologic study shall include but is not limited to:

(i) Structure contour maps drawn on a geologic marker unit 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 to the gas storage project area.

(iv) Representative geophysical~~electric~~ log to a depth below the deepest gas storage~~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 including, but not limited to: isopach, ~~isoGOR~~isogor, ~~isoBAR~~isobar, structure- contour, seismic reflection surveys, 3-D, water-oil, or gas-oil ratio maps of the project and other information which will delineate all known features such as faults and fractures within the area of influence of the 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 and buffer zone showing the location and status of all wells within ~~and adjacent to~~ the boundary of the area of review and buffer zone. 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) Well construction ~~Casing~~ diagrams, including all data specified in Section 1726.4.1, of all wells that are within the area of review and that penetrate into or through the gas storage reservoir within ~~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 well construction ~~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 well construction ~~casing~~ diagrams must demonstrate that:

(i) Plugged and abandoned wells shall have cement across all perforations or open-hole completions 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; and

(ii) Wells that are not plugged and abandoned and that have been inactive for more than two years shall have cement plugs across all hydrocarbon zones, flow zones, lost circulation zones, and corrosive zones and the base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, and groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

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

(H) Wells completed into or penetrating through the intended gas storage reservoir shall be identified and evaluated for containment assurance for the design of gas storage operation volumes, pressures, and flow rates. The operator shall~~ould~~ 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 wells and disposal zones~~horizons~~, mining, and other subsurface industrial activities not associated with oil and gas production or gas storage operations within the area of review and buffer zone, to the extent it is publicly available.

~~(6)~~(7) A gas storage injection and withdrawal plan that includes all of the following:

(A) Maximum anticipated surface injection pressure and maximum anticipated daily volume and 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 for plant, lines, and wells, where employed.

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

~~(7)~~(8) The name and API number of all gas storage wells and other wells that are part of the underground gas storage project.

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

~~(8)~~(10) Any performance metrics data required by the Division.

(b) Updated data shall be provided to the Division if conditions change or if more accurate data become available.

(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, provided that the alternative data demonstrate to the Division's satisfaction, at least as comprehensively as would be accomplished by the data specified in subdivision (a) 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 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.4.1 Well Construction ~~Casing~~ Diagrams.

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

(1) Well construction ~~Casing~~ diagrams shall 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, to include depths, on associated equipment such as surface and subsurface safety valves, packers, gas lift mandrels;

(H) Depths of casing 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) Drill bit 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 weight (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);

(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 or horizontal wells, a directional survey shall be provided with inclination, azimuth measurements, and surface location.

(4) Well construction ~~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 well construction ~~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 and 3106, Public Resources Code. Reference: Section 3106, 3220 and 3403.5 Public Resources Code.

1726.5 Well Construction Requirements.

(a) Operators shall design, drill, 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, or the environment. Where not superseded by requirements in subdivision (b), operators shall conform to requirements in Secs. 1722.2, 1722.3, 1722.4, 1722.5, 1722.6, 1723 (including all subsections), 1724.3, and 1724.4.

(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) At minimum, the primary mechanical barrier shall be comprised of the following elements:

(i) Production casing extended to the ~~to~~ surface with adequate cement with the required integrity to contain the maximum operational reservoir pressure;

(ii) Tubing with packer and production casing wellhead tree with the required integrity to contain maximum operational reservoir pressure; and

(iii) Surface Controlled Subsurface Safety Valve (SCSSV) or production casing master ~~Christmas tree~~ valve with the required integrity to contain reservoir pressure that halts flow through the well.

(B) At minimum, the secondary mechanical barrier shall be comprised of the following elements:

(i) Casing cement that overlaps at least 100 feet between two concentric casings, with good quality cement bond;

(ii) Wellhead with annular valves and seals and the required integrity to contain reservoir pressure;

~~(ii)~~(iii) Casing with hanger and seal assembly;

~~(iii)~~(iv) Tubing hanger with seals; and

~~(iv)~~(v) Redundant ~~Christmas tree~~ master valves on tubing and production casing to allow for well control and work under pressure.

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

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

(4) The production casing is of sufficient size, weight, grade, competency, and depth and cemented as required 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 operational pressures and velocities. The production casing shall be ~~is~~ free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work shall be ~~are~~ sealed with cement and pressure tested 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 and operational pressures. 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 or shall be 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~~ 500 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 or other sealants and placement techniques are designed for the specific wellbore conditions, pressures, formations, and type of repairs.

(10) Cement bond log or cement 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 confining zone~~aprock~~, 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 confining zone~~aprock~~ 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) and is at least as effective and protective as the requirements specified in subdivision (b). 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).

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

1726.6 Mechanical Integrity Testing.

(d) The operator shall, at a minimum, conduct the following mechanical integrity testing on each gas storage well:

(1) A temperature and noise log shall be conducted at least annually to ensure integrity of the production casing. All logging shall be conducted in accordance with the minimum standards and procedures approved by the Division. An appropriate repeat section (generally 100' to

200' interval) will be run to verify log data accuracy and made a part of the log presentation unless well conditions warrant otherwise. All anomalies identified shall be immediately reported to the appropriate district office and evaluated and described ~~xplained~~ to the Division's satisfaction.

(2) A casing wall thickness inspection to determine corrosion potential, shall employ~~ing~~ such methods as magnetic flux and ultrasonic technologies, and shall be performed at least every two years to determine if there are possible issues with production casing integrity. An appropriate repeat section (generally 100' to 200' interval) will be run to verify log data accuracy and made a part of the log presentation unless well conditions warrant otherwise. The results shall be compared against prior results and any other available data to determine the extent of 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.

~~(2)~~(3) A pressure test of the production casing on all injection and withdrawal wells shall be conducted at least every two years. If injection in the gas storage well is through tubing and packer, then the pressure test shall be performed on ~~of~~ the casing-tubing annulus of the well. If injection is through the production casing only, a mechanical packer or bridge plug shall be set immediately above the gas storage perforations and the pressure test performed on the entire string of production casing. Pressure tests shall be conducted at a pressure at least as high as 115 percent of the maximum operating pressure. A lower testing pressure may be approved by the Division if necessary to ensure that testing does not compromise the mechanical integrity of the well. If a lower test pressure is approved by the Division for that reason and the test successfully demonstrates mechanical integrity, the operational pressure of the well will be reduced accordingly by Administrative Order. Pressure testing shall be conducted with liquid unless the Division approves pressure testing with gas. If a pressure test does not indicate a final stabilized pressure and less than 10 percent pressure loss over a minimum 30 minute test, then the well shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may require a longer duration of up to 60 minutes pressure testing based on individual circumstances. 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.

(e) 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 pressure tested prior to commencement of injection operations and shall be pressure tested to the maximum allowable operating pressure and adhere to the testing requirements in subdivision (a) (3) ~~as per subdivision (a)~~. Operators shall conduct additional testing to establish baseline integrity conditions as required by the Division.

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

(g) The appropriate district office shall be notified at least 48 hours in advance of ~~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.

~~(g)~~(h) Any alternative testing program approved by the Division shall be at least as effective and protective as the protocols required in subdivisions (a) and (b).

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

1726.7 Monitoring Requirements.

(a) In addition to the mechanical integrity testing requirements under Section 1726.6, the operator shall monitor for the presence of annular gas by measuring and recording annular and injection pressures at least once a day at all annuli. Based on guidance from the Division and API RP 90-2, ~~T~~the operator shall evaluate any anomalous annular gas or pressure occurrence and report ~~it~~ any indication of a loss of well integrity or formation integrity to the Division immediately. This requirement may be met by employment of a real-time data gathering system, such as Supervisory Control and Data Acquisition (SCADA).

(b) The material balance behavior of an underground gas storage project's storage reservoir shall be monitored relative to the original design and expected reservoir behavior. Unexpected conditions detected during monitoring shall be evaluated and corrected 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. Material balance support data will be submitted to the Division at least once a year, or upon request. 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 operational pressure versus gas 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 in the first porous and permeable zone directly above the confining zone ~~aprock~~ 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 well 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 or other Division-approved geophysical logs to confirm the location of gas being injected into the intended storage reservoir, as needed.

(c) The operator of an underground gas storage project shall employ a real-time data gathering system, such as Supervisory Control and Data Acquisition (SCADA) on all gas storage wells, by January 1, 2020.

(d) The operator shall continually track all wells that are within the area of review and the buffer zone and that are in the same or a deeper zone as the gas storage project and ensure that all such wells that are not plugged and abandoned and that have been inactive for more than two years have cement plugs across the gas storage zone(s), all hydrocarbon zones, the base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content, and groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.

(e) 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 or other Division-approved leak detection methodology. 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 if the California Air Resources Board adopt and implement regulations with the same or stricter requirements.

AUTHORITY:
Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, 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 maximum injection and operational pressures 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 in advance of ~~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 safety valve or addressing an inoperable surface or subsurface safety valve may be approved by the

Division, but must be at least as effective and protective as the requirements of this subdivision.

(b) At least annually, the operator of an underground gas storage project shall pressure 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 redundant valves on production casing and tubing to provide isolation of the wells from the pipeline system and to allow for entry into the wells under pressure.

(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 that meet API standards and are rated to withstand the maximum injection and operational pressures.

~~(d)~~(e) Concrete barriers or steel bollards shall be emplaced around all sides of the wellhead to act as barriers to protect the wellhead from potential damage and release of gas.

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

1726.8 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 an appropriate schedule for carrying out training and drills to validate the plan. There must be documented demonstration of competency with respect to training and drills. The drills shall address the readiness of personnel and their interaction with equipment including required third party service providers and their current contact information.

(b) The emergency response 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) Protocols for emergency reporting and response to appropriate government agencies

(4) Specification of personnel roles and responsibilities;

(5) Internal and external communication protocol;

(6) Emergency contact information including area codes; and

(7) Procedures for notification.

AUTHORITY:

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

Appendix 1: EDF Redlines on Well Construction Rules of General Applicability

§ 1722.2. Casing Program

Each well shall have casing designed to provide anchorage for blowout prevention equipment and to seal off fluids and segregate them for the protection of all oil, gas, and freshwater zones. All casing shall be steel or steel alloy casing that has been hydrostatically pressure tested with an applied pressure that exceeds the maximum pressure to which the pipe will be subjected in the well. API casing specifications and recommended practices shall govern the design, manufacturing, testing and transportation of such casing. Casing manufactured to API specifications must meet strict requirements for compression, tension, collapse and burst resistance. All casing strings shall be designed to withstand anticipated collapse, burst, and tension forces with the appropriate design factor provided to obtain a safe operation.

At a minimum, casing shall be centralized within one joint of casing from the top, at the shoe, above and below a stage collar or diverting tool, if run, and through all protected water zones. In nondeviated holes, a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to within one joint of casing from the bottom of the cellar, or casing shall be centralized by implementing an alternative centralization plan approved by the Division.

Casing setting depths shall be based upon geological and engineering factors, including but not limited to the presence or absence of hydrocarbons, formation pressures, fracture gradients, lost circulation intervals, and the degree of formation compaction or consolidation. All depths refer to true vertical depth (TVD) below ground level.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3219 and 3220, Public Resources Code.

§ 1722.3. Casing Requirements

~~(a)~~ Conductor casing. This casing shall be cemented at or driven to a maximum depth of 100 feet. Exceptions may be granted by the appropriate Division district deputy if conditions require deeper casing depth.

Surface casing. Surface casing shall be cemented into or through a competent bed and at a depth that will allow complete well shut-in without fracturing the formation immediately below the casing shoe and cemented to surface. As a general guideline, the surface casing for prospect wells shall be cemented at a depth that is at least 10 percent of the proposed total depth, with a minimum of 200 feet and a maximum of 1,500 feet of casing. Prior to drilling out below the surface casing shoe, the surface casing shall be pressure tested to a minimum of 1,500 psi and/or at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives. A formation integrity test (FIT) must be completed if a BOP is installed on the surface casing. The FIT must be completed after drilling out below the surface casing shoe, into at least 20 feet, but not more than 50 feet, of new formation in order to assess the integrity of the cement in the surface casing annulus at the surface casing shoe.

A second string of surface casing, cemented into or through a competent bed, shall be required in prospect wells if the first string has not been cemented in a competent bed or if unusual drilling hazards exist. In development wells, the surface casing requirement shall be determined on the basis of known field conditions. As described above, perform appropriate casing pressure test and FIT. The appropriate Division district deputy may vary these general surface casing requirements, including the adoption of a field rule, consistent with known geological conditions and engineering factors, to provide adequate protection for freshwater zones and blowout control.

Intermediate casing. This casing may be required for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. As described in 1722.3(b) perform casing pressure test prior to drill out of casing shoe and perform FIT.

Production casing. This casing shall be cemented and, when required by the Division, tested for fluid shutoff above the zone or zones to be produced by running a cement evaluation tool. The test may be witnessed by a Division inspector. The production casing string or production liner must be centralized in a manner that will provide for proper zonal isolation by the cement.

When the production string does not extend to the surface, at least 100 feet of overlap between the production string and next larger casing string shall be required. This overlap shall be cemented and tested by a fluid-entry test to determine whether there is a competent seal between the two casing strings. A pressure test may be allowed only when such test is conducted pursuant to an established field rule. The test may be witnessed by a Division inspector.

Authority: Section 3013, Public Resources Code. Reference: Sections 3106 and 3220, Public Resources Code.

§ 1722.4. Cementing Casing

Cementing shall be by the pump and plug method. A cement sheath of at least 1 inch shall fill the space between the outside diameter of the casing tube and the drilled diameter of the borehole (i.e. the annular gap).

Cement must conform to API Specification 10A (Specification for Cement and Material for Well Cementing). The Division may require specific cement additives, quantities, or types in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or provide safer conditions in the well or the area surrounding the well.

Casing strings must stand under pressure until the cement has reached a compressive strength of at least 500 psi (to be achieved within 24 hours at most) in the zone of critical cement before drilling out the plug, initiating a test, or disturbing the cement in any way.

Surface casing shall be cemented with sufficient cement to fill the annular space from the shoe to the surface. Surface casing must be cemented to the surface with full returns. If cement falls back or fails to circulate, remedial action needs to be undertaken immediately. Intermediate and production casings, if not cemented to the surface, shall be cemented with sufficient cement to fill the annular space to at least 500 feet above oil and gas zones, and anomalous pressure intervals. Sufficient cement shall also be used to fill the annular space to at least ~~100~~500 feet above the base of the freshwater zone, either by lifting cement around the casing shoe or cementing through perforations or a cementing device placed at or below the base of the freshwater zone. All casing shall be cemented in a manner that ensures proper distribution and bonding of cement in the annular spaces. The appropriate Division ~~district deputy~~ may require ~~a cement bond log~~an appropriate cement evaluation tool, temperature survey, or other survey to determine cement fill behind casing.

~~fill behind casing.~~

On intermediate or production casing strings, if fluid returns, lift pressure, displacement and/or other operations indicate inadequate cement coverage, operator shall (i) run a radial cement evaluation tool, a temperature survey, or other test approved by the Division to identify the top of cement, (ii) submit a plan of remediation to the Division for approval and (iii) implement such plan by performing additional operations to remedy such inadequate coverage prior to continuing drilling operations.~~If it is determined that the casing is not cemented adequately by the primary cementing operation, the operator shall recement in such a manner as to comply with the above requirements.~~ If supported by known geologic conditions, an exception to the cement placement requirements of this section may be allowed by the appropriate Division district deputy.

Authority: Section 3013, Public Resources Code. Reference: Sections 3106, 3220 and 3222-3224, Public Resources Code.

§ 1722.5. Blowout Prevention and Related Well Control Equipment

~~Blowout prevention and related well control equipment shall be installed, tested, used, and maintained in a manner necessary to prevent an uncontrolled flow of fluid from a well.~~All blowout prevention equipment shall be installed, operated, tested and maintained in accordance with API RP 53 (Recommended Practices for Blowout Prevention Equipment Systems) and conform to BOP requirements of the Division. The required working pressure rating of all blowout preventers and related equipment shall be based on known or anticipated subsurface pressure, geologic conditions, or accepted engineering practices, and shall exceed the maximum anticipated pressure to be contained at the surface. Division of Oil, Gas, and Geothermal Resources publication No. MO 7, "Blowout Prevention in California," shall be used by Division personnel as a guide in establishing the blowout prevention equipment requirements specified in the Division's approval of proposed operations.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3219 and 3220, Public Resources Code.

UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

PRE-RULEMAKING DISCUSSION DRAFT

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Deleted text is shown in ~~strikethrough~~.

…

(a) An initial mechanical integrity test (MIT) must be performed on all injection and withdrawal wells to ensure the injected fluid is confined to the approved zone or zones. An MIT shall consist of a two-part demonstration as provided in ~~subsections~~ subdivisions (k~~j~~)(1) ~~and (2).~~ - (5).

(1) Prior to commencing injection or withdrawal operations, each injection or withdrawal well must pass a pressure test of the casing or casing-tubing annulus~~-tubing annulus~~ to determine the absence of leaks. Thereafter, the ~~annulus of~~ casing or casing-tubing annulus of each underground injection project well must be tested at least once every five years; ~~prior to recommencing injection operations following the repositioning or replacement of downhole equipment;~~ or whenever requested by the ~~appropriate~~ Division ~~district deputy~~. The casing or casing-tubing annulus shall be tested to the maximum allowable surface pressure, or 200 psi, whichever is greater. With approval from the Division, casing or casing-tubing annulus may be tested at a lower pressure, provided that there is a corresponding reduction of the maximum allowable surface pressure for the injection well. Pressure testing is required of wells subject to this rule whether or not they are of active status. ~~even if the well is no longer an active injection well or gas storage withdrawal well, unless the well is no longer approved for injection or gas withdrawal and it has been converted to observation or is producing oil or gas.~~

~~(1)~~(2) Internal mechanical integrity testing

(a) For Class II wells, the pressure test shall be conducted on the casing-tubing annular space at the maximum allowable surface injection pressure for 30 minutes with no more than a 10% decline. A corrosion-resistant fluid shall be emplaced within the casing-tubing annulus of all wells utilizing a tubing and packer for injection. For approved wells injecting without tubing and packer, a mechanical bridge plug shall be set in the bottom of the production casing and the pressure test approved in accordance to the pass/failure criteria as in the above.

(b) Gas storage injection and withdrawal wells shall be pressure tested. ~~-~~Pressure tests shall be conducted at a pressure at least as high as 115 percent of the maximum operating pressure. A lower testing pressure may be approved by the Division if necessary to ensure that testing does not compromise the mechanical integrity of the well. If a lower test pressure is approved by the Division for that reason and the test successfully demonstrates mechanical integrity, the operational pressure of the well will be reduced accordingly by Administrative Order. Pressure testing shall be conducted with liquid unless the Division approves pressure testing with gas. If a pressure test does not indicate a final stabilized pressure and less than 10 percent pressure loss over a minimum 30 minute test, then the well shall not be used for injection or withdrawal without subsequent approval from the Division.
~~with an inert gas at a test pressure of at least 120% of the maximum allowable injection or gas storage operating pressure. The pressure test shall be for a minimum of 60 minutes with no more than a 10% decline.~~

~~(2)~~(3) ~~When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity.~~ The second test (external mechanical integrity) of a two-part MIT ~~-~~shall demonstrate that there is no fluid migration behind the casing, tubing, or packer. This may be done by a combination of a tools such as the temperature survey, radioactive tracer, 360 degree cement evaluation tools capable of showing cement channels, or noise log performed in accordance with Section 1724.10.1, or other methods approved by the Division that demonstrate~~s~~ external mechanical integrity. The operator shall submit a plan stating the tool or combination of the tools to be used to demonstrate the second test of a two-part MIT to the Division for approval. At a minimum, Class II wells shall be evaluated using a cement evaluation tool, and gas storage wells shall be evaluated using a combination of cement evaluation tool and temperature/noise logging.

~~(3)~~ The second part of the MIT must be performed and results approved by the Division prior to commencement ~~within three (3) months after c o m m e n c e m e n t o f i~~ of injection or withdrawal operations. ~~has commenced.~~ Thereafter, ~~water-disposal~~ injection and withdrawal wells shall be tested for external mechanical integrity at least once each year, or on a testing schedule approved by the Division based upon consideration of the age of the well, geology, and operational factors~~; waterflood wells~~

~~shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years~~. Such well testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, any subsurface wellbore remedial action, or whenever requested by the Division. The second part of the MIT is not required if the injection or withdrawal well becomes ~~is~~ temporarily abandoned~~inactive~~, but shall be performed after ~~within~~ 180 days of the injection or withdrawal well becoming inactive, and every 180 days until the well is returned to service or permanently plugged and abandoned ~~three months after recommencing injection~~.

The second part of the MIT is not required for a cyclic steam well that has never injected more than 100 gallons per foot. ~~appropriate Division district deputy . The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause.~~

- (3) All anomalies encountered during either part of the required MIT shall be reported and explained to the Division within 24 hours.

…

(n) Within sixty days of the effective date of this section, unless the Division authorizes additional time, and on the following schedule thereafter, the operator of an underground gas storage project shall perform a monthly operational manual test of the master valve and wellhead pipeline isolation valve by opening and closing the valves to ensure the valves are in proper working order. An annual isolation pressure test shall be performed on each gas storage injection and withdrawal well to demonstrate that the equipment is properly functioning and verifies the ability to isolate the well. The operator shall submit documentation of the results of annual pressure testing done under this subdivision within 10 days of completing the testing, but shall immediately notify the Division if testing indicates a lack of function or failure.

…

1724.10.1. Mechanical Integrity Testing

(a) In addition to all other applicable federal, state, and local requirements, a radioactive tracer performed under Section 1724.10(k~~j~~)(2) shall adhere to the following:

(1) Testing must be conducted while injecting, and the operator shall ensure that adequate fluid ~~water~~ can be supplied for the test. The injection rate shall be governed by the ability of the operator to track the radioactive tracer as it moves downward, but the injection rate should be as close to the maximum injection rate as practical.

(2) There shall be an adequate pressure differential across the tubing wall in order for the for the test method to be valid.

(3) The casing valve must be opened during testing and there must be no fluid flow. If fluid flow continues from the casing valve, the casing-tubing annulus shall be evaluated.

(4) Gamma ray detector sensitivity shall be set so that lithologic effects are just identifiable.

(5) The spectral gamma ray detector must be centralized to the extent feasible.

(6) A tool sketch showing tool diameter along with ejector and detector spacing should be on the log header. Spacing shall be verified by measurement at the surface.

(7) Caliper surveys are required if scale or other buildup is present within the wellbore to a degree that may interfere with the test.

(8~~5~~) A baseline ~~background~~ spectral gamma ray log survey shall be run over the interval to be tested and shall be recorded before any radioactive material is ~~introduced~~ ejected into the well.

(9~~6~~) The test shall record measurements over a period of three to five minutes with the tool stationary at two points which are representative of the extremes of natural radiation within the interval to be tested.

(10~~7~~) The release of a slug of radioactive material must be above the interval to be tested. Slug ejection duration should not change from shot to shot.

(11~~8~~) The slug of radioactive material shall be followed with the logging tool or make repeated passes upward through the slug as it moves down the well. All logging shall be done at a single logging speed which is appropriate for the injection rate to allow quantitative measurements of deflections to be evaluated.

(12~~9~~) If repeated passes are used, the logs resulting from the slug-tracking exercise should overlap so that the return of radioactivity to the level which existed before the slug's passing is demonstrated for the entire length of the section of the well being tested. The logs of all passes should be presented as a composite log on a common depth track. If means to differentiate the log traces are available no other presentation is required. If the traces cannot be differentiated on the composite log, they should also be presented individually.

(13~~0~~) After any ejection, the slug of radioactive material must be followed until it has moved below the interval being tested. If the slug splits, both slug portions must be accounted for.

(14~~1~~) After completion of the passes, a final log should be made through the entire tested interval to check for residual radioactivity which might be associated with exit of tracer material from the well bore.

(15~~2~~) If a well is injecting at a rate that creates a fluid velocity greater than one foot per second, radioactively treated beads shall be introduced into the well and evaluated according to parts 8 through 11 above.

(16~~3~~) Steam injection wells shall be tested using an inert gas tracer.

(b) A temperature log performed under Section 1724.10(k~~j~~)(2) shall adhere to the following:

(1) The well must be taken off injection at least 24 hours but not more than 48 hours prior to performing the temperature log to allow for stabilization, unless an alternate duration has been approved by the Division.

(2) All casing and all internal annuli shall be completely fluid filled.

(3~~2~~) The logging tool shall be calibrated and centralized to the extent feasible.

(4~~3~~) The well must be logged from the top of the well to the bottom~~surface downward~~, lowering the tool at a rate of no more than 30 feet per minute.

(5~~4~~) If the well has not been taken off injection for at least 24 hours before the log is run, comparison with either a second log run six hours after the time the log of record is started or a log from another well at the same site showing no anomalies shall be available to demonstrate normal patterns of temperature change.

(6~~5~~) The log data shall be provided to the Division electronically in either LAS or ASCII format.

(c) A noise log performed under Section 1724.10(k~~j~~)(2) shall adhere to the following:

(1) Noise logging may not be carried out while injection is occurring.

(2) All casing and all internal annuli shall be completely fluid filled.

(3~~2~~) Noise measurements must be taken at intervals of 100 feet to create a log on a coarse grid.

(4) Noise logging shall occur upwards from the bottom to the top of the well.

(5~~3~~) If any anomalies are evident on the coarse log, there must be a construction of a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

(6~~4~~) Noise measurements must be taken at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

(A) The base of the lowermost bleed-off zone above the injection interval;

(B) The base of the lowermost USDW; and

(C) In the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval.

(7~~5~~) Additional measurements must be made to pinpoint depths at which noise is produced.

(8~~6~~) A vertical scale of 1 or 2 inches per 100 feet shall be used.

(d) Cement evaluation logging performed under Section 1724.10 (j) (2) shall adhere to the following:

(1) Cement evaluation tools shall be calibrated and centralized to the extent feasible.

(2) Cement evaluation tools shall be run first under surface pressure and then under pressure of at least 1500 psig.

(3) If gas is present within the casing where cement evaluation is being conducted, then a padded cement evaluation tool shall be run in lieu of an acoustic tool.

AUTHORITY:

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

Appendix 3 – EDF Proposed Gas Storage Metrics

1. Number of wells performing mechanical integrity testing (MIT)
    a. Number of wells performing internal MIT
        i. Number of wells that failed internal MIT
            1. Types of failures
            2. Percentage of those wells returned to service
    b. Number of wells performing external MIT
        i. Number of wells that failed external MIT
            1. Types of failures
            2. Percentage of those wells returned to service
2. Number of permits issued
    a. Newly drilled
    b. Conversions
3. Number of permits denied or withdrawn (with explanation)
4. Number of wells identified for corrective (remedial) action
    a. Types of corrective action
    b. Percentage of those wells with corrective action performed
5. Number of wells with gas release incidents
    a. Types of incidents
    b. Number of days gas was released with estimated gas volumes
6. Number of wells placed into temporary abandoned status
7. Number of wells plugged and abandoned
8. Number of Administrative Orders issued suspending well operations
    a. Percentage of those wells returned to compliance in 180 days

723. Plugging and Abandonment-General Requirements

The application submitted to plug an abandoned well must include:

(i) The reason(s) for abandoning the well;

(ii) The date that the well was last produced, including rates and types of ~~of~~ fluids;

(iii) a well construction diagram showing the type, age, condition (including but limited to any known junk, lost fish, casing patches, liners, and all perforations) and proposed placement of cement, removal of uncemented casing, tubing, and any other mechanical devices (e.g. plugs, packers);

(iv) Identification of corrosive zones, flow zones, lost circulation zones, disposal zones, protected water and hydrocarbon-bearing zones;

(v) a proposed plugging procedure, including the manner of placement, kind, size, and location by measured depth of existing and proposed plugs; and

(vi) the proposed timing for plugging and abandonment and notification to the Division prior to commencement of plugging operations.

(a) Cement Plugs. In general, cement plugs will be placed across specified intervals by circulation or squeeze method, subject to approved exceptions to protect oil and gas zones, to prevent degradation of usable waters, to protect surface conditions, and for public health and safety purposes. Cement may be mixed with or replaced by other substances with adequate physical proper- ties, which substances shall be approved by the Supervisor. The application of these mixed materials and other substances to particular wells shall be at the discretion of the Division~~district deputy~~. Wait-on-Cement (WOC) time and tagging of cement plugs shall be accomplished.

~~(a)~~(b) All cement used for plugging shall be of a composition approved by the Division, and the Division may require that specific cement compositions be used in certain situations. Cement must conform to API Specification 10A (Specification for Cement and Material for Well Cementing). The Division may require additional cement additives or cement in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or provide safer conditions in the well or the area around the well.

~~(b)~~(c) Hole Fluid. Mud fluid having the proper weight and consistency to prevent movement of other fluids into the well bore shall be placed across all intervals not plugged with cement, and shall be surface poured into all open annuli. The entire well bore shall be in static conditions at the time the cement plugs are placed

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3219 and 3228, Public Resources Code.

§ 1723.1. Plugging of Oil or Gas Zones

(a) Plugging in an Open Hole. A cement plug shall be placed to extend from the total depth of the well or from at least 100 feet below the bottom of each oil or gas zone, to at least 100 feet above the top of each oil or gas zone.

(b) Plugging in a Cased Hole. All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

~~(b)~~(c) … For wells in which the production casing has been cemented to isolate all protected water strata and all hydrocarbon strata, and a cement evaluation tool has been run and the cement is verified to be in good condition and determined to be a barrier to fluid and gas migration in the annulus:~~.~~

As a minimum for ~~a cased-hole~~ production casing plugging and abandonment, the bottom cement plug ~~special requirement~~ shall include a cement plug across all ~~extending from at least 25 feet below the top of the uppermost~~ perforated intervals to at least 100 feet above the top of the perforations, ~~the top of the perforations~~, the top of the landed liner, ~~the casing cementing point~~, the water shutoff holes, or the zone, whichever is highest. ~~(d) Bridge Plug.~~ Directly above the bottom cemented plug and within the production casing,~~In a multiple zone completion~~, a mechanical ~~a single bridge~~ plug shall be set, pressure tested, and then additionally sealed with at least 250 feet of cement ~~is~~ placed on top of the plug to ensure isolation of the production zone or gas storage reservoir as applicable~~above the lowermost zone may be allowed in lieu of cement through that zone if the zone is isolated from the upper zones by cement behind the casing~~. Subsequent mechanical ~~bridge~~ plugs are not allowed unless separated by cement plugs meeting the requirements of Section 1723.1(b). Temporary bridge plugs must be removed and replaced with cement plugs prior to shallower zone completions or well abandonment.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Section 3228, Public Resources Code.