

Docket	:	<u>A.17-11-009</u>
Exhibit Number	:	<u>ORA-11-SA</u>
Commissioner	:	<u>C. Rechtschaffen</u>
ALJ	:	<u>S. Roscow</u>
Witness	:	<u>N. Stannik</u>



OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

**The Office of Ratepayer Advocates’
Report on
Pacific Gas and Electric Company’s
Cost of Service and Rates for Gas
Transmission and Storage
Services for the Period 2019 - 2021**

Natural Gas Storage Strategy (NGSS)

Supporting Attachments

San Francisco, California
June 29, 2018

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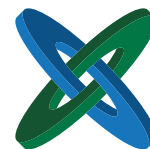
Long-Term Viability of Underground Natural Gas Storage in California

An Independent Review of Scientific and Technical Information



FULL REPORT

A Commissioned Report prepared by the
California Council on Science and Technology



CCST
CALIFORNIA COUNCIL ON
SCIENCE & TECHNOLOGY

A nonpartisan, nonprofit organization established via the California State Legislature
– making California's policies stronger with science since 1988

Table 1.1-1. Characteristics of UGS facilities with gas injection via wells designated GS (gas storage) by DOGGR in California in 2015.

Field ¹	Capacity (Bcf) ²		Start year ⁴	Storage Pool Type	Colocated active production	County	Owner
	2006	2015					
Aliso Canyon	82.0	86.2	1973	Oil	Oil	Los Angeles	SoCalGas
Gill Ranch Gas	0.0	20.0	20105	Gas	Gas	Madera	Gill Ranch LLC (75%), PG&E (25%)
Honor Rancho	23.0	27.0	1975	Oil	None	Los Angeles	SoCalGas
Kirby Hill Gas	5.0	15.0	19756	Gas	Gas	Solano	Rockpoint
La Goleta Gas	21.5	19.7	19427	Gas	Gas	Santa Barbara	SoCalGas
Lodi Gas	17.0	17.0	2001	Gas	None	San Joaquin	Rockpoint
Los Medanos Gas	17.4	17.9	1976	Gas	Gas	Contra Costa	PG&E
McDonald Island Gas	82.0	82.0	1962	Gas	Gas	San Joaquin	PG&E
Montebello	Unlisted		1956	Oil	Oil	Los Angeles	SoCalGas
Playa del Rey	2.6	2.4	19428	Oil	None	Los Angeles	SoCalGas
Pleasant Creek Gas	2.3	2.3	1962	Gas	Gas ⁷	Yolo	PG&E
Princeton Gas ³	0.0	11.0	20125	Gas	None	Colusa	AGL (through Pivotal Energy Development)
Wild Goose Gas	20.5	75.0	1998	Gas	None	Butte	Rockpoint
Total - independents	42.5	138.0					
Total - PG&E	101.7	102.2					
Total - N.	144.2	240.2					
Total - S. (SoCalGas)	129.1	135.3					
Total	273.3	375.5					

- 1 As per DOGGR's production and injection databases
- 2 U.S. EIA (2016)
- 3 Operated under the name "Central Valley"
- 4 Except as noted, from earliest injection noted is for storage in DOGGR's annual reports (available at http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx)
- 5 Annual reports after 2009 do not note storage; beginning of storage in this period based on first injection year in DOGGR's injection database.
- 6 Storage activities in the Domengine pool have ceased for several multi year periods since first commencing in 1975; storage in the Wagenet pool commenced in 2008.
- 7 Earlier annual reports do not list any storage, but this start year is also implied by the statement "the field will probably be utilized as a gas storage reservoir by Pacific Lighting Corporation" in annual report Volume 26 (1940-41).
- 8 The annual report for 1942 (DOG, 1942) lists injection in the second half of 1942, but does not note it was for storage, however storage in this field is noted in the 1943 annual report (DOG, 1943). Start of storage taken as 1942 based on injection that year.

REQUIREMENTS FOR CALIFORNIA UNDERGROUND GAS STORAGE PROJECTS

SECOND REVISED TEXT OF PROPOSED REGULATIONS

Text added in the originally proposed regulations is in plain text.

Text deleted in the originally proposed regulations is shown in ~~strikethrough~~.

Text added in the first revised proposed regulations is in double underline.

Text deleted in the first revised proposed regulations is shown in ~~double strikethrough~~.

Text added in the second revised proposed regulations is in **bold double underline**.

Text deleted in the second revised proposed regulations is shown in ~~**bold double strikethrough**~~.

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

Subchapter 1. Onshore Well Regulations

Article 3. Requirements

DELETE SECTION 1724.9:

~~1724.9 Gas Storage Projects~~

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

~~—(a) Characteristics of the cap rock, such as areal extent, average thickness, and threshold pressure.~~

~~—(b) Oil and gas reserves of storage zones prior to start of injection, including calculations.~~

~~—(c) List of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.~~

~~–(d) Proposed waste water disposal method.~~

ADOPT NEW ARTICLE 4 WITH SECTIONS 1726, 1726.1, 1726.2, 1726.3, 1726.3.1, 1726.4, 1726.4.1, 1726.4.2, 1726.4.3, 1726.5, 1726.6, 1726.6.1, 1726.7, 1726.8, 1726.9, AND 1726.10:

Article 4. Requirements for Underground Gas Storage Projects

1726. Purpose, Scope, and Applicability.

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

AUTHORITY:

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

1726.1. Definitions.

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

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

(2) “~~Caprock~~ Confining strata” means the rock layer or layers at the ~~upper boundary~~ boundaries of the storage reservoir acting as the primary barriers preventing upward migration of fluids.

(3) “Fluid” means liquid or gas.

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

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

(6) “Underground gas storage project” means a project for the injection and withdrawal of natural gas into an underground reservoir for the purpose of storage. An underground gas storage project includes the reservoir used for storage, the confining ~~caprock~~ strata, gas storage wells, observation wells, and any other wells approved for use in the project. An underground

gas storage project also includes the wellheads and, to the extent that they are subject to regulation by the Division, attendant facilities, and other appurtenances.

AUTHORITY:

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

1726.2. Approval of Underground Gas Storage Projects.

(a) A Project Approval Letter shall be obtained from the Division before any injection 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 of an underground gas storage project as set forth in the Project Approval Letter are subject to approval by the Division and shall be noted in either an addendum to the Project Approval Letter or a revised Project Approval Letter. Underground gas storage project operations shall not occur or continue unless consistent with the terms and conditions of a current Project Approval Letter.

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

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

AUTHORITY:

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

1726.3. Risk Management Plans.

(a) For each underground gas storage project, the operator shall submit a project-specific Risk Management Plan to the Division for review and approval. For underground gas storage projects in existence at the time that this section goes into effect, the operator shall submit a Risk Management Plan in accordance with the requirements of this section within six months of the effective date of this section. If the Division identifies any deficiencies in the Risk Management Plan, then the Division will consult with the operator and identify an appropriate timeframe for correcting the deficiency. ~~The Risk Management Plan shall demonstrate to the Division's satisfaction that stored gas will be confined to the approved zone(s) of injection and~~

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

(b) The Risk Management Plan shall demonstrate to the Division's satisfaction that stored gas will be confined to the approved reservoir and that risks of damage to life, health, property, the environment, or natural resources are identified and **prevented or** effectively mitigated. In accordance with subdivision (c), the Risk Management Plan shall evaluate threats and hazards associated with operation of the underground gas storage project and identify **prevention and mitigation** protocols that effectively address those threats and hazards. The Division may, in its discretion, require additional data, additional risk assessment, or modification of **prevention and mitigation** protocols. Risk assessment and **prevention and mitigation** protocols in the Risk Management Plan shall be consistent with and additional to any other existing requirements.

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

(1) Identification of potential threats and hazards associated with operation of the underground gas storage project, including identification of the most important potential accident scenarios associated with operation of the underground gas storage project;

(2) ~~Evaluation~~ Quantitative risk assessment of the probability of threats, and hazards, and their consequences related to the events, using an appropriate methodology identified by the operator that includes:

(A) Evaluation of the frequency and range of consequences, including estimates of the uncertainties in the numerical values;

(B) Identification of the principal equipment failures, external initiating events, and operational errors associated with threats and hazards, and quantification of the impact of these occurrences on the probability of and consequences of the threats and hazards;

(C) Identification of the engineered or natural features that most affect the extent of the consequences of threats and hazards, and a quantification of their relative roles, including an estimate of the uncertainties in the quantification;

(3) Identification of possible ~~prevention~~ **prevention and mitigation** protocols to reduce, manage, or monitor risks, including evaluation of the efficacy and cost-effectiveness of the prevention protocols;

(4) Risk assessment on a well-by-well basis, to the extent that risks identified are specific to wells;

(5) Prioritization of risk **prevention and** mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat;

~~(6)~~ Selection and implementation of ~~prevention~~ **prevention and mitigation** protocols;

~~(7)~~ Documentation of the risk assessment process, including description of the basis for selection of ~~prevention~~ **prevention and mitigation** protocols;

~~(8)~~ Data feedback and validation throughout the risk assessment process; and

~~(9)~~ Regular, periodic risk assessment reviews to update information and evaluate the effectiveness of ~~prevention~~ **prevention and mitigation** protocols employed, which shall occur not less than once every three years and in response to changed conditions or new information.

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

(1) Well construction and design standards, consistent with the requirements of Section 1726.5 and including specification of the life expectancy of individual mechanical well barrier elements. If the operator has ~~gas storage~~ wells that do not conform with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan and schedule for either bringing the nonconforming wells into compliance or plugging and abandoning the wells in accordance with Public Resources Code section 3208. The work plan and schedule shall provide for full compliance with Section 1726.5 within seven years, with at least 10 percent of the nonconforming wells addressed in the first year and the total percentage at least 15 percent of the nonconforming wells addressed increasing by 15 percent in each subsequent year. The work plan shall include ~~prevention~~ **prevention and mitigation** protocols for monitoring and testing each well that is not yet in compliance with the requirements of Section 1726.5 so as to mitigate risks associated with the well to the extent feasible.

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

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

(B) Gas composition, 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 of well;
 - (I) The risks of ~~well~~ sabotage;
 - (J) The current and predicted development of the surrounding area as reflected in the local general ~~plan~~, topography and regional drainage systems, and environmental considerations;
 - (K) Topography and local wind patterns; and
 - (L) Evaluation of geologic hazards such as seismicity, ~~active faults~~, landslides, subsidence, and potential for tsunamis.
- (3) A schedule for verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage. The mechanical integrity testing protocols for gas storage wells shall, at a minimum, adhere to the requirements of Section 1726.6.
- (4) Corrosion monitoring, ~~and evaluation~~, and mitigation including consideration of at least the following:
- (A) Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;
 - (B) Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressures, temperatures, and compositions on the corrosion potential of wellbore fluids and analysis of partial pressures;
 - (C) Corrosion potential of annular and packer fluid;
 - (D) Corrosion potential of current flows associated with cathodic protection systems;
 - (E) Corrosion potential of all formation fluids, including fluids in formations above the storage zone; and
 - (F) Corrosion potential of uncemented casing.
- (5) Ongoing monitoring of casing pressure changes at the wellheads of gas storage wells, analysis of facility flow erosion, ~~hydrate potential~~, individual facility component capacity and fluid disposal capability at intended gas and liquid flow rates and pressures, and analysis of the specific impacts that the intended operating pressure and temperature ranges could have on the corrosive potential of fluids in the system.
- (6) Monitoring protocols in accordance with the requirements of Section 1726.7.
- (7) Ongoing verification and demonstration of the integrity of the reservoir including demonstration that reservoir integrity will not be adversely impacted by operating conditions.
- (8) Analysis and risk assessment of hazards associated with the formation of hydrates, and scale from the well stream under various pressure, temperature, and flow rates, including those beyond expected operating parameters.
- (9) Analysis and risk assessment of natural and geologic hazards including, and not limited to seismicity, faults, subsidence, inundation by tsunamis, sea level rise, and floods.
- (10) Analysis and risk assessment of hazards associated with the potential for explosion or fire.
- (11) If observation wells are employed, identification and documentation of baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level.

~~(12) Prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat.~~

(12) An assessment of human factors in operating and maintenance procedures. The human factors assessment shall consider staffing levels; the complexity of tasks; the length of time needed to complete tasks; the level of training, experience and expertise of employees; the human-machine and human-system interface; the physical challenges of the work environment in which the task is performed; employee fatigue and other effects of shiftwork and overtime; communication systems; and the understandability and clarity of operating and maintenance procedures. The human factors assessment shall also consider utilization of error-proof mechanisms, automatic alerts, and automatic system shutdowns.

~~(13) Safety training for on-site personnel.~~An effective training program with clearly stated goals. The training program shall specify the type and frequency of training and the risk assessments and **prevention and** mitigation protocols addressed.

(14) An equipment maintenance program that includes training and proactive inspection, repair, and replacement of equipment at risk of failure so as to ensure safe operation.

(15) An emergency response plan that at a minimum accounts for the threats and hazards identified in the Risk Management Plan and that complies with the requirements of Section 1726.3.19.

(16) Requests for notice from land use agencies of local land use decisions that could affect the Risk Management Plan, and providing notification to the Division of significant pending land use decisions.

~~(e)~~ The operator shall adhere to the risk **prevention and** mitigation protocols detailed in its Risk Management Plan unless variance has been approved by the Division in writing.

~~(f)~~ The Division will provide completed Risk Management Plans and significant updates to the Risk Management Plans to the California Public Utilities Commission and post them on the Division's public internet website. If any part of a Risk Management Plan is subject to confidential treatment, then the Division will segregate the confidential records and only provide them if the California Public Utilities Commission has agreed to treat the records as confidential.

AUTHORITY:

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

1726.3.1 Emergency Response Plan.

(a) The operator of an underground gas storage project shall have an emergency response plan approved by the Division and ready for immediate implementation. The emergency response plan shall specify a schedule for carrying out drills to validate the plan. The drills shall address the readiness of personnel and their interaction with equipment including required third party service providers and their current contact information. The emergency response plan shall identify and consider onsite personnel, outside emergency responders, and potentially

affected communities. The operators shall provide local ~~first responders-emergency response entities~~ at least 30 days to review and provide input on the emergency response plan.

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

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

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

(1) Clearly written and communicated emergency response plan policy, goals, and objectives;

(2) An incident management system designed to address resource management, communication systems, and incident documentation;

~~(3)~~ Written actions plans establishing assigned authority to the appropriate ~~qualified~~ person(s) at a facility for initiating effective emergency response and control;

~~(4)~~ Accident-response measures that outline response activities, leakage mitigation approaches, and well control processes for well failure and full blowout scenarios;

~~(5)~~ Prepositioning, as feasible, and identification of materials and personnel necessary to respond to leaks, including materials and equipment to respond to and stop the leak itself as well as to protect public health and safety.

~~(6)~~ A schedule for regular drills, providing for an opportunity for involvement of the Division and local ~~first responders-emergency response entities~~, and providing an opportunity for ~~surprise~~ drills initiated by local ~~first responders-emergency response entities~~;

(7) An effective training program with clearly stated goals. The training program shall specify the type and frequency of training and the emergency scenarios addressed;

(8) Recordkeeping for all drills and training;

~~(9)~~ A schedule for regular evaluation and update of the emergency response plan;

~~(10)~~ Protocols for emergency reporting and response to appropriate government agencies;

~~(11)~~ Specification of personnel roles and responsibilities;

~~(12)~~ Internal and external communication protocol;

~~(13)~~ Up-to-date ~~E~~ emergency contact information including area codes; and

~~(14)~~ A protocol for public notice of a large, uncontrollable leak to any potentially impacted community, as defined in the ~~risk management plan~~ Risk Management Plan, if the leak cannot be controlled within 48 hours of discovery by the operator.

(d) The operator shall review and update the emergency response plan after key personnel changes, but no less often than once every three years. When reviewing and updating the emergency response plan, the operator shall again provide local emergency response entities at least 30 days to review and provide input on the emergency response plan.

AUTHORITY:

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

1726.4. Underground Gas Storage Project Data Requirements.

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

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

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

(3) ~~Proposed~~ Produced water disposal method.

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

(A) The pressure required to inject fluids, particularly at total inventory, shall not exceed the design pressure limits of the ~~reservoir, caprock, wells, well heads, piping, pipelines, or other~~ associated facilities; or the fracture pressure gradient of the reservoir or confining strata.

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

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

(A) Statement of primary purpose of the project.

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

(C) A comprehensive geologic characterization of the gas storage project including lithology of the storage zone or zones and sealing mechanisms as well as all formations encountered from surface to the deepest well in the project. The geologic characterization shall include any information that may be required to ensure injected or withdrawn gas and other reservoir fluids ~~do not~~ have an adverse effect on the project or pose a threat to life, health, property, the

environment, or natural resources. The geologic characterization shall include potential pathways for ~~gas-fluid~~ migration and areas or formations where potential entrapment of migrated ~~gas-fluid~~ could occur. Information to accompany the geologic characterization shall include but is not limited to:

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

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

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

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

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

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

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

(F) ~~Casing diagrams, including a~~ All data specified in Section 1726.4.1, provided in the form of graphical casing diagrams or flat file data sets, for ~~of~~ all wells that are within the area of review and that are in the same or a deeper zone as the gas storage ~~project~~ reservoir, including directionally drilled wells that intersect the area of review in the same or deeper zone. ~~The casing diagrams must demonstrate that the wells in the area will not be a potential conduit for gas to migrate outside of the approved zone of gas storage or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources. At a minimum, the casing diagrams must demonstrate that plugged and abandoned wells have cement across all perforations and extending at least 100 feet above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the intended zone of injection.~~

(G) Identification of all wells associated with oil and gas production that are within the area of review but that are not in the same or a deeper zone as the underground gas storage project,

including description of the total depth of the well and the estimated top of the gas storage reservoir below the well.

(H) Wells completed in or penetrating through the intended gas storage reservoir shall be identified and evaluated for containment assurance for the design of gas storage operation volumes, pressures, and flow rates. The operator ~~should~~ shall 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~~ the boundaries of the underground gas storage project.

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

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

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

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

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

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

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

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

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

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

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

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

(g) For underground gas storage projects in existence at the time that this section goes into effect, the operator shall submit revised and updated project data in accordance with the requirements of this section within ~~90-180~~ days of the effective date of this section.

AUTHORITY:

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

1726.4.1. Casing Diagrams.

(a) Casing diagrams submitted under Section 1726.4~~(a)(5)(F)~~ shall adhere to the following requirements:

(1) Casing diagrams shall at a minimum include all of the following data:

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

(B) Date the well was spudded;

~~(CB)~~ Ground elevation from sea level;

~~(DE)~~ Reference elevation (i.e. rig floor or Kelly Bushing);

~~(ED)~~ Base of groundwater that has 3,000 or less milligrams per liter of total dissolved solids content;

~~(FE)~~ Base of groundwater that has 10,000 or less milligrams per liter of total dissolved solids content;

~~(GF)~~ Sizes, weights, grades, and connection types of casing and tubing;

~~(HE)~~ Details on associated equipment such as subsurface safety valves, packers, and gas lift mandrels;

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

~~(JF)~~ Depths of perforation intervals, water shutoff ~~holes~~ perforations, 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;

~~(KJ)~~ Hole size diameter and depth of drilled hole;

~~(LK)~~ Cement plugs inside casings, including top and bottom of cement plug and the date(s) the plug(s) was emplaced, with method of determination;

~~(ML)~~ All cement fill behind casings, including top and bottom of cemented interval, with method of determination;

~~(NM)~~ Type and density of fluid between cement plugs;

~~(Q)~~ Depths and names of the formation(s), zone(s), and geologic markers penetrated by the well, including the top and bottom of the gas storage zone(s) and the top and bottom of the ~~caprock confining strata~~;

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

~~(Q)~~ All of the information listed in this paragraph for all previously ~~ly~~ drilled or sidetracked well bores; ~~and~~

(R) Identification of wellhead and wellhead valve assembly equipment by model and pressure rating.

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

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

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

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

(6) When multiple boreholes are drilled in a well, all of the information listed in this section is required for both the original hole and for any subsequent redrilled or sidetracked well bores.

(b) In lieu of graphical casing diagrams, operators may satisfy the requirements of ~~section 1724.6(a)(5)(F)~~ **Section 1726.4(a)(5)(F)** by submitting a flat file data set containing all of the information described in this section.

AUTHORITY:

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

1726.4.2. Evaluation of Wells Within the Area of Review.

(a) The following requirements apply, at minimum and subject to augmentation by the Division as the Division deems appropriate on a project-specific basis, to ensure that wells within the area of review will not be a potential conduit for fluid migration outside the approved gas storage zone:

(1) All wells within the area of review and that are in the same or a deeper zone as the gas storage reservoir, including directionally drilled wells that intersect the area of review in the same or deeper zone, shall be evaluated for the potential to allow fluid to migrate outside of the approved zone of gas storage. The operator should identify, and the Division confirm, wells which may require integrity testing or well logging in order to provide the requisite assurances that such wells will not act as conduits for fluid migration.

(2) Plugged and abandoned wells within the area of review shall have cement across all perforations and extending at least 100 feet above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the approved

gas storage zone. 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.

(3) If a plugged and abandoned well within the area of review does not meet the cement specifications of subdivision (a)(2), the Division may approve an alternative demonstration that the well will not be a potential conduit for fluid migration outside the approved gas storage zone. The Division's approval of such an alternative demonstration shall be supported by written findings by the Division that identify each plugged and abandoned well in the area of review that does not meet the cement specifications of subdivision (a)(2), specify how the well(s) do not meet the requirements of subdivision (a)(2), and identify the ~~bases~~ basis for the Division's approval of the alternative demonstration.

AUTHORITY:

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

1726.4.32. Records Management.

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

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

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

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

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

AUTHORITY:

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

1726.5. Well Construction Requirements.

(a) Operators shall design, construct, modify, and maintain gas storage wells and every other well that penetrates the gas storage reservoir of the operator's underground gas storage project 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, the environment, or natural resources. **This section does not apply to wells that have been plugged and abandoned in accordance with Public Resources Code section 3208.**

(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~~ constructed with both primary and secondary mechanical well barriers to isolate the storage gas within the storage reservoir and transfer storage gas from the surface into and out of the storage reservoir.

(A) The primary mechanical barrier is the barrier that is exposed to the withdrawal or injection flow stream. The primary mechanical barrier shall be able to withstand full operating pressure as demonstrated by ~~the periodic~~ pressure testing required under Section ~~1726.6(a)(1)~~ 1726.6(a)(3) and through annular pressure monitoring as required under Section 1726.7(a). An example of a well configuration that meets the minimum requirements for a primary mechanical barrier is a well configuration that includes:

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

(B) The secondary mechanical barrier is not exposed to the withdrawal or injection flow stream under normal operations. The secondary mechanical barrier shall be able to withstand full operating pressure as demonstrated by ~~periodic annular~~ the pressure testing required under Section ~~1726.6(a)(1)~~ 1726.6(a)(3) and casing evaluation logs as required under Section 1726.6(a)(2). In the event of a primary mechanical barrier failure, the secondary mechanical barrier shall be able to contain the leaking fluids until the primary mechanical barrier is re-established. An example of a well configuration that meets the minimum requirements for a secondary mechanical barrier is a well configuration that includes:

- (i) Wellhead components, including casing hanger and seal assembly; and
- (ii) Production ~~C~~ casing to surface.

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

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

(4) The production casing is of sufficient size, weight, grade, competency, and depth to maintain the well integrity, and is compatible with fluid chemical composition. The production

casing is designed to accommodate fluids on injection and withdrawal at the maximum expected operational pressures and velocities. The production casing is free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work are sealed to establish hydraulic isolation.

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

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

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

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

(B) Intermediate and production casings, if not cemented to the surface, are cemented in accordance with the requirements of Section 1722.4 ~~with sufficient cement to fill the annular space to at least 500 feet above the gas storage reservoir, oil and gas zones or anomalous pressure intervals and to at least 100 feet above the base of groundwater that has 3,000 or less milligrams per liter of total dissolved solids content.~~

(8) For new wells, the cementing operations used a cement slurry designed for the anticipated wellbore and formation conditions.

~~(9)~~ Cement plugs provide for effective zonal isolation.

~~(10)~~ Any remedial cement slurry and placement techniques are designed for the specific wellbore conditions, formations, and type of repairs.

~~(11)~~ Cement bond log or evaluation acceptable to the Division is on file that indicates an adequate cement bond between the casing, cement, and geologic formations. A competent cement bond extends across the ~~caprock~~ confining strata, and at least 100 feet above the gas storage reservoir.

~~(12)~~ For wells equipped with tubing and packer, packer is set in cemented casing within ~~caprock~~ confining strata 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). An alternative method of well design and construction under this subdivision shall include 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. The Division will determine on a case-by-case

basis whether the operator has effectively demonstrated that a gas storage well that does not conform to the criteria in subdivision (b) meets the performance standard in subdivision (a).

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

AUTHORITY:

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

1726.6. Mechanical Integrity Testing.

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

(1) A temperature and noise log shall be conducted at least annually to ensure integrity. Logging shall include a repeat section of no less than 200 feet, preferably across intervals where anomalies are present. All anomalies identified. If an anomaly is identified that indicates a possible loss of or threat to the mechanical integrity of the well, then the operator shall be immediately ~~reported~~ report the anomaly to the appropriate district office ~~and explained to the Division's satisfaction.~~ If the operator is unable to explain any anomaly to the Division's satisfaction, then the well shall not be used for injection or withdrawal without subsequent approval from the Division.

(2) A casing wall thickness inspection to estimate internal and external corrosion, employing such methods as magnetic flux ~~and or~~ ultrasonic technologies, shall be performed at least once ~~at least~~ every 24 months to determine if there are possible issues with casing integrity. Logging shall include a repeat section of no less than 200 feet, preferably across intervals where anomalies are present. The results shall be compared against prior results and any other available data to determine the corrosion rate. If the casing wall thickness inspection indicate that within the next 24 months thinning of the casing will diminish the casing's ability to contain 115 percent of the well's maximum allowable operating pressure utilizing Barlow's equation or another method acceptable to the Division, then the well shall be remediated and shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent casing wall thickness inspection schedule for a well if the operator demonstrates to the Division's satisfaction that the well's corrosion rate is low enough that biennial inspection is not necessary.

~~(3) A pressure test of the production casing shall be conducted at least once every 24 months. If injection in the gas storage well is through tubing and packer, then the pressure test shall be of the casing tubing annulus of the well. Pressure tests shall be conducted at a pressure at least as high as 115 percent of the maximum operating pressure. Pressure testing shall be conducted with liquid unless the Division approves pressure testing with gas. The pressure test shall be for one hour. A pressure test is successful if during the final thirty minutes~~

~~of continuous pressure testing the pressure gauge does not show more than a 10 percent overall decline in pressure from the initial pressure and if during the final five minutes of continuous pressure testing the pressure gauge does not show more than an average of 0.075 percent decrease in pressure per minute. The Division may modify the testing parameters on a case-by-case basis if, in the Division's judgement, the modification is necessary to ensure an effective test of the integrity of the casing. If a pressure test is not successful, then the well shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent pressure testing schedule for a well if the operator demonstrates to the Division's satisfaction that other measures to ensure the integrity of the well warrant less frequent pressure testing.~~

(3) Pressure testing of the production casing shall be conducted at a minimum frequency determined on a well-by-well basis under Section ~~1726.3(e)(3)~~ 1726.3(d)(3), provided that the well-specific minimum pressure testing frequency has been reviewed and approved by the Division. If the Division has not approved a well-specific minimum pressure testing frequency for a well as part of the Risk Management Plan, then the operator shall pressure test the well at least once every 24 months. If injection in the gas storage well is through tubing and packer, then the pressure test shall be of the casing-tubing annulus of the well. Pressure testing shall be conducted in accordance with the parameters specified in Section 1726.6.1. If a required pressure test is not successfully completed, then the operator shall immediately notify the Division and the well shall not be used for injection or withdrawal without subsequent approval from the Division.

(b) A newly constructed gas storage well, or a reworked gas storage well that has had its existing production casing modified from its previous condition during rework activities, shall be tested as per subdivision (a) prior to use. The Division may waive some or all of the mechanical testing requirements for a reworked gas storage based on the nature of the work performed.

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

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

AUTHORITY:

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

1726.6.1. Pressure Testing Parameters.

(a) Pressure testing required under Section 1726.6 shall be conducted according to the following parameters:

(1) Pressure testing shall be conducted with a liquid unless the Division approves pressure testing with gas.

(2) If pressure testing will be conducted with a liquid that contains additive other than brine, corrosion inhibitors, or biocides, then the operator shall consult with the Division regarding the contents of the liquid prior to commencing testing.

(2) The wellbore shall be filled with a stable column of fluid that is free of excess gasses.

(3) Pressure tests shall be recorded and a calibrated gauge shall be used that can record a pressure ~~that is no greater than 230 percent of the maximum allowable injection pressure~~ with an accuracy within one percent **of the maximum allowable injection pressure.**

(4) Pressure tests shall be conducted at an initial test pressure of at least 115 percent of the maximum allowable injection pressure at the wellhead.

(5) The pressure test shall be continuous for one hour. A pressure test is successful if the pressure gauge does not show more than a 10 percent decline from the initial test pressure in the first 30 minutes, and does not show more than a 2 percent decline from the pressure after the first 30 minutes in the second 30 minutes.

(b) The Division may modify the testing parameters on a case-by-case basis if, in the Division's judgement, the modification is necessary to ensure an effective test of the integrity of the casing.

AUTHORITY:

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

1726.7. Monitoring Requirements.

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

(b) The operator shall monitor the material balance ~~behavior~~ of an underground gas storage project's storage reservoir relative to the original design and expected reservoir behavior. The operator shall evaluate and correct unexpected conditions detected during monitoring in order to avoid an incident or loss. Monitoring frequency ~~should~~ shall be based on factors such as reservoir and well fluid loss potential and flow potential, as outlined in the Risk Management Plan.

(1) The operator shall submit material balance support data to the Division at least once a year, or upon request by the Division.

(2) Acceptable reservoir integrity monitoring and analysis methods include any of the following **four methods**, or an equally effective method approved by the Division:

~~(A)~~(4) Monitoring average reservoir pressure versus inventory and comparing that to expected conditions in order to allow for the discovery and correction of any anomalies or unexpected conditions. Liquid level shall be taken into account when utilizing observation wells.

Semiannual field shut-in tests, usually conducted at the point of seasonally high and low inventories, shall be conducted for inventory verification.

~~(B)(2)~~ Installation and monitoring of strategically located observation wells in the vicinity of spill points, within an aquifer, and above the ~~caprock-confining strata~~. **Observation wells shall be 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.**

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

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

(c) The operator shall immediately report to the Division any instance of an unintended surface or cellar gas release of any size, in any location within the area of review of the underground gas storage project. Unless the operator demonstrates to the Division's satisfaction that the gas is not from the underground gas storage project or a gas storage well, Division may require ~~the operator shall to~~ chemically fingerprint the gas from such a release ~~within 48 hours of detection~~, and the operator shall provide the results of the gas analysis to the Division as soon as they are available.

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

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

(2) The real-time data gathering system shall have alarms set for each annulus to monitor for pressure indicative of potential leaks or potential migration of gas. The alarms shall alert the operations ~~monitoring~~ center if pressure exceeds preconfigured set points. For tubing, the alarm set point shall not be higher than the maximum allowable ~~surface injection pressure at the wellhead~~. For ~~annuli~~ the annulus between production casing and tubing, the alarm set point shall be determined based on annular fluid, the initial pressure when the packer was set, and operational configuration. For strings without any anticipated surface pressure, such as surface or intermediate casings, the alarm set point shall not be higher than 100 psi or the alarm set point approved under subdivision (d)(3)(C).

(3) If there is sustained casing pressure above 100 psi in a string without anticipated surface pressure, and it is believed to be caused by shallow gas or other fluid migration, then the operator shall do the following:

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

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

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

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

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

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

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

an underground gas storage project if the California Air Resources Board approves a monitoring plan under its regulations for that facility.

AUTHORITY:

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

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

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

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

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

(d) The operator shall equip all ports on the wellhead assembly above the casing bowl of gas storage wells with valves, blind flanges, or similar equipment that are rated to withstand the maximum operational pressures.

AUTHORITY:

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

1726.9. Well Leak Reporting.

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

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

(2) A leak from a gas storage well that is above 10,000 parts per million by volume total hydrocarbons, as measured using methodology that the operator has demonstrated will provide

consistent and reliable measurements, such as US EPA Reference Method 21, for more than five days; or

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

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

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

AUTHORITY:

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

1726.10. Requirements for Decommissioning.

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

(1) Identification of the intended use of the wells and facilities after decommissioning, including a plan for obtaining requisite approvals for the use.

(2) A plan for managing remaining gas in the underground gas storage reservoir.

(3) A plan for repurposing or decommissioning all wells and facilities associated with the underground gas storage project.

(4) Consultation with the California Public Utilities Commission.

(5) Any other information requested by the Division.

(b) An underground gas storage project is subject to the requirements of this article until the Division has approved a Decommissioning Plan and the Division has certified that the operator has completed all steps required under the Decommissioning Plan to the Division's satisfaction.

AUTHORITY:

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

**PACIFIC GAS AND ELECTRIC COMPANY
 Gas Transmission and Storage Rate Case 2019
 Application 17-11-009
 Data Response**

PG&E Data Request No.:	ORA_064-Q01		
PG&E File Name:	GTS-RateCase2019_DR_ORA_064-Q01		
Request Date:	May 7, 2018	Requester DR No.:	064
Date Sent:	May 22, 2018	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Larry D. Kennedy, Jr.	Requester:	Nils Stannik

SUBJECT: PG&E TY 2019 GAS TRANSMISSION AND STORAGE (GT&S) APPLICATION

QUESTION 1

Please provide a list of all wells at Los Medanos and Pleasant Creek. For each well, provide the year in which the well was most recently reworked, as well as the in-service date for the capital additions that reflect this most recent reworking.

ANSWER 1

A list of all the active storage wells at Los Medanos and Pleasant Creek, the year in which the well was most recently reworked if it has been reworked, and the in-service date¹ for the capital additions for the most recent rework are provided in attachment GTS-RateCase2019_DR_ORA_064-Q01Atch01. This attachment does not include two wells at Los Medanos that were plugged and abandoned in 2017.

¹ The attachment includes the in-service date for capital additions back to 1997. Data prior to that year is not readily available.

ORA 64 Q1

Active Gas Storage Wells at Los Medanos and Pleasant Creek Storage Fields

MATs 3L3 and 76J

Facility	Well Name	Year Most Recently Reworked	Capital In-Service Dates for Most Recent Rework (1997 - 2017)
Los Medanos	GINO-3	2017	12/29/2017
Los Medanos	LM-01A	N/A	N/A
Los Medanos	LM-02A	2016	6/21/2016
Los Medanos	LM-03A	2000	7/11/2000
Los Medanos	LM-04B	2013	6/7/2013
Los Medanos	LM-05B	2013	6/7/2013
Los Medanos	LM-06B	2006	7/31/2006
Los Medanos	LM-07C	1992	----
Los Medanos	LM-09C	2011	4/27/2011
Los Medanos	LM-10C	2003	8/5/2003
Los Medanos	LM-11C	2015	8/19/2015
Los Medanos	LM-12C	2016	6/7/2016
Los Medanos	LM-13C	N/A	N/A
Los Medanos	LM-14C	N/A	N/A
Los Medanos	LM-15C	1999	8/16/1999
Los Medanos	LM-16D	2004	11/30/2004
Los Medanos	LM-17D	1997	5/12/1997
Los Medanos	LM-19D	2007	7/5/2007
Los Medanos	LM-20D	N/A	N/A
Los Medanos	LM-21D	2015	9/30/2015
Pleasant Creek	PC 3-2	2011	8/24/2011
Pleasant Creek	PC 3-3	2011	8/25/2011
Pleasant Creek	PC 3-4	2010	7/1/2010
Pleasant Creek	PC 4-1	N/A	N/A
Pleasant Creek	PC 3-5	N/A	N/A
Pleasant Creek	PC 3-1	N/A	N/A
Pleasant Creek	PC 4-2	N/A	N/A

NOTES

N/A means well has not been reworked

Los Medanos wells 8C and 18D were retired and abandoned in 2017 and are not included here

**PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2019
Application 17-11-009
Data Response**

PG&E Data Request No.:	ORA_064-Q04		
PG&E File Name:	GTS-RateCase2019_DR_ORA_064-Q04		
Request Date:	May 7, 2018	Requester DR No.:	064
Date Sent:	May 23, 2018	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Larry Kennedy	Requester:	Nils Stannik

QUESTION 4

For each well identified in response to Question 1 above, please provide:

- the type/category of rework needed to bring the well into compliance with forthcoming DOGGR regulations;
- the cost on a per-well basis; and
- PG&E’s best schedule/timeline estimate for re-working each well from start to finish.

If any of the requested information is not available on a per-well basis, please indicate as such, explain why, and provide the information on a group-of-wells basis, with each group being as small as possible.

If any of the requested information is not available, please indicate as such, explain why, and provide PG&E’s best estimate.

ANSWER 4

The type of work needed to bring the storage wells into compliance with the draft DOGGR regulations is described in Chapter 6 prepared testimony, Section C.1, on pages 6-19 through 6-23. The scope of work for retrofitting a storage well is summarized on pages 6-20, line 1 to page 6-21, line 5.

As described in Chapter 6 prepared testimony on page 6-21, lines 12 – 18, PG&E plans on retrofitting two wells at both the Los Medanos and Pleasant Creek Storage fields to comply with the draft DOGGR regulations. The remaining wells at the two natural gas storage fields are not planned to be retrofitted. PG&E plans to decommission all the wells at these two storage fields as explained in Chapter 6 prepared testimony, Section D, pages 6-34, line thirteen through 6-35, line twelve.

Part of PG&E’s proposals in Chapter 6 also include a request for a two-way balancing account (see Chapter 6 prepared testimony on page 6-7, line 20 through page 6-9, line 24). As described in that testimony, this balancing account is being proposed because of uncertainty around the timing of the DOGGR regulations and the timing of a Commission decision on PG&E’s Natural Gas Storage Strategy.

While PG&E had not selected the specific wells to be retrofitted when the forecast was developed, the retrofit costs are based on costs for material, labor and equipment (see Chapter 6 prepared testimony, page 6-22, lines 8 – 26 for more information). The unit costs for the work involved in the retrofit projects are provided on Chapter 6 Workpaper Tables 6-13, 6-14 and 6-15.

The costs to perform the retrofits at Los Medanos and Pleasant Creek are provided in GTS-RateCase2019_DR_ORA_064-Q4A4ch01. References to the unit costs in Chapter 6 workpapers are provided in the attachment. PG&E's forecast for well retrofits are based on an estimated 17 days of drill rig time at each well. Typically, the entire retrofit project is expected to take much longer than 17 days as additional work such as site preparation, clearances, and mobilization activities prior to the utilizing the drill rig can take up to 30 days to complete. Similarly, after the drill rig activity is complete, project completion on the wellhead, clean-up and demobilization can take another 30 days to complete.

Attachment ORA 64 Q4

Forecast Los Medanos and Pleasant Creek Well Retrofit Work in 2018

WP Table 6-11 Line No.	Planning Order	Planning Order Description	MAT	Operative Date	Units	Unit Cost	2018 Forecast	Notes
51	5774294	LM Rework Well Reliability/DHSV (2018)	3L3	10/15/2018	2	\$2,293,720	\$4,587,440	Unit Cost Detail from WP Table 6-13, Line 2
53	5776419	PC Rework Well Reliability/DHSV (2018)	3L3	10/15/2018	2	\$2,293,720	\$4,587,440	Unit Cost Detail from WP Table 6-13, Line 2
57	5776423	LM Rework Cement Wells (2018)	3L3	10/15/2018	2	\$548,321	\$1,096,641	Unit Cost Detail from WP Table 6-14, Line 2
58	5776425	PC Rework Cement Wells (2018)	3L3	10/15/2018	2	\$548,321	\$1,096,641	Unit Cost Detail from WP Table 6-14, Line 2
62	5776160	LM Rework Intall Tubing & Packer (2018)	3L3	10/15/2018	2	\$149,957	\$299,915	Unit Cost Detail from WP Table 6-15, Line 16
63	5776161	PC Rework Intall Tubing & Packer (2018)	3L3	10/15/2018	2	\$149,957	\$299,915	Unit Cost Detail from WP Table 6-15, Line 16

\$11,967,992 Total Retrofit/Rework cost
 \$5,983,996 Total cost at each storage field