

UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

TEXT OF REGULATIONS

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CALIFORNIA CODE OF REGULATIONS, TITLE 14 DIVISION 2. DEPARTMENT OF CONSERVATION CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 1. Onshore Well Regulations

Article 2. Definitions

1720.1. Definitions

The following definitions are applicable to this subchapter:

(a) "Area of review" means an area around each injection well that is part of an underground injection project. The area of review shall be proposed by the operator as part of an underground injection project application or review, but may be specified by the Division depending on project-specific data and any other factors determined by the Division. The area of review is either:

(1) The calculated lateral distance encompassing within and beyond the intended injection zone to which the pressures in the intended injection zone may cause the migration of the injection fluid or the formation fluid; or

(2) A fixed one-quarter mile radius.

(b) "Cyclic steam injection well" means an injection well that injects steam into an underground formation and then subsequently produces hydrocarbons.

(c) "Disposal injection well" means an injection well into which fluid is injected primarily for purposes of disposal rather than enhancing the recovery of hydrocarbons.

(d) "Fluid" means liquid, gas, or steam.

- (e) “Freshwater” means water that contains 3,000 mg/l TDS or less.
- (f) “Injection well” means a well into which fluids are being injected as part of an underground injection project, or that is approved by the Division for such purpose.
- (g) “Injection zone” means the defined three-dimensional space with fixed boundaries where fluid injected by an underground injection project is anticipated to occupy or otherwise be located. The injection zone may include more than one formation or strata.
- (h) “Mechanical integrity” means that all well barrier envelopes, including but not limited to, the tubing, packer, wellhead, and casing of a well, reliably perform their primary functions of containing pressure and are free from leakage.
- (i) “Mg/l TDS” means milligrams per liter of total dissolved solids content.
- (j) “Steamflood injection well” means an injection well that injects steam into an underground formation for purposes of enhancing the hydrocarbon recovery of other producing wells.
- (k) “Surface expression” means a flow, movement, or release from the subsurface to the surface of fluid or other material such as oil, water, steam, gas, formation solids, formation debris, material, or any combination thereof, that is outside of a wellbore and that appears to be caused by injection operations.
- (l) “Surface expression containment measure” means an engineered measure to contain or collect the fluids or materials from a surface expression, including but not limited to, subsurface collection systems, collection wells, cisterns, culverts, French drains, collection boxes, earthen ditches, containment berms, or gas hoods or other gas collection systems.
- (m) “Underground injection project” means sustained or recurring injection into one or more wells over an extended period into an approved injection zone for the purpose of enhanced oil recovery, disposal, storage, pressure maintenance, or subsidence mitigation. Examples of underground injection projects include, but are not limited to, waterflood injection, steamflood injection, cyclic steam injection, and disposal injection.
- (n) “Underground source of drinking water” or “USDW” means an aquifer or its portion which has not been approved by the United States Environmental Protection Agency as an exempted aquifer pursuant to the Code of Federal Regulations, title 40, section 144.7, and which:
- (1) Supplies a public water system, as defined in Health and Safety Code section 116275; or

(2) Contains a sufficient quantity of groundwater to supply a public water system, as defined in Health and Safety Code section 116275; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l TDS.

(o) "Waterflood injection well" means an injection well that injects water or water-based liquid into an underground formation for purposes of enhancing the hydrocarbon recovery of other producing wells.

(p) "Water supply well" means a well that provides water for domestic, municipal, industrial, or irrigation purposes, but does not include a well associated with oil and gas operations.

AUTHORITY:

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

Article 4. Underground Injection Control

1724.6. Approval of Underground Injection Projects

(a) Operators shall obtain a Project Approval Letter from the Division for each underground injection project before any injection occurs as part of the underground injection project. Approval must be obtained from this Division before any subsurface injection or disposal project can begin. This includes all EPA Class II wells and air- and gas-injection wells. The operator requesting approval for such a project must provide the appropriate Division district deputy with the data specified in Section 1724.7 and any data that, in the judgment of the Supervisor-Division, are pertinent and necessary for the proper evaluation of the project.

(b) The Project Approval Letter shall specify the location and nature of the underground injection project, as well as the conditions of the Division's approval. All underground injection projects shall be operated in accordance with the requirements of this subchapter and the terms and conditions of the current Project Approval Letter.

(c) Any subsequent modification of an underground injection project requires the prior approval of the Division and shall be memorialized in either an addendum to the Project Approval Letter or a revised Project Approval Letter.

(d) The Division will review existing underground injection projects periodically, but not less than once every three years, to verify compliance with the requirements of this subchapter and the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letters to ensure that they are effectively preventing damage to life, health, property, and natural resources. Project Approval Letters are subject to suspension, modification, or rescission by the Division.

(e) If the Division determines that the operation of an underground injection project is inconsistent with this subchapter or the terms and conditions of a current Project Approval Letter, or otherwise poses a threat to life, health, property, or natural resources, then upon written notice from the Division injection operations shall cease immediately, or as soon as it is safe to do so. Underground injection projects or injection operations suspended upon written notice from the Division or for any of the reasons specified under Section 1724.13 shall not resume without subsequent written approval from the Division.

(f) Within sixty days after transfer of an underground injection project to a new operator, the new operator shall meet with Division staff to ensure a complete understanding of the applicable requirements and terms and conditions of the Project Approval Letter.

(g) Project Approval Letters shall expire, and be deemed null and void, upon the first day following twenty-four consecutive months of no injection at the underground injection project, and a new approval process and Project Approval Letter would be required prior to restarting injection.

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

1724.7. Project Data Requirements

~~—(Note: See Section 1724.8 for special requirements for cyclic steam projects, and Section 1724.9 for supplementary requirements for gas storage projects.)~~

~~The data required to be filed with the district deputy include the following, where applicable:~~

(a) An underground injection project shall be supported by data filed with the Division that demonstrates to the Division's satisfaction that injected fluid will be confined to the

approved injection zone and that the underground injection project will not cause damage to life, health, property, or natural resources. The engineering study, geologic study, and injection plan described in subdivisions (a)(1) through (a)(3) of this section shall demonstrate to the Division's satisfaction that injection fluid will not migrate out of the approved injection zone through another well, geologic structure, fault, fracture, or fissure, hole-in-casing, or other pathway, considering project duration, volume of fluid to be injected, and other relevant factors. The operator is responsible for ensuring that the data are current and accurately reflective of the project setting and operation throughout the operating life of the project. The data filed with the Division shall include, at a minimum:

~~(1) (a) An engineering study, including but not limited to:~~

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

~~(2) Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations.~~

~~(3) Reservoir fluid data for each injection zone, such as oil gravity and viscosity, water quality, and specific gravity of gas.~~

(A) A description of how the area of review was determined, including calculations and assumptions.

(B) A map of the area of review showing the location of the following:

(i) All wells within and adjacent to the boundary of the area of review;

(ii) All water supply wells that are within the area of review and identified in public records or otherwise known to the operator; and

(iii) Any underground disposal horizons, mining, and other subsurface industrial activities not associated with oil and gas production within the area of review, to the extent such information is publicly available or otherwise known to the operator.

(C) A compendium of the following information:

(i) For all wells depicted in subdivision (a)(1)(B) (including water supply wells to the extent information is known or publicly available), the API numbers, or other identifying information for wells that do not have API numbers, and the wellbore paths, total depths, and depths of completion interval(s) of the wells;

(ii) The type, status, and ownership of water supply wells depicted in subdivision (a)(1)(B); and

~~(iii)(4) Casing diagrams, including cement plugs, and actual or calculated cement fill behind casing. All data specified in Section 1724.7.1, provided in the form of graphical~~

casing diagrams or flat file data sets, for ~~of all idle, plugged and abandoned, or deeper-~~ zone producing wells that are within the area of review and that are completed in or penetrating the injection zone for the underground injection project or a deeper zone, including directionally drilled wells that intersect the area of review in the injection zone or a deeper zone. ~~affected by the project, and evidence that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources.~~

~~(D) (5)~~ The planned well-drilling and plugging and abandonment program to complete the project, including a flood-pattern map, if applicable, showing all injection, production, and plugged and abandoned wells, and unit boundaries.

~~(2) (b)~~ A geologic study, including but not limited to:

~~(A)~~ Reservoir characteristics of the injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations. The scope of the geologic characterization shall encompass the reservoir rock, caprock and sealing mechanisms, the injection zone including the vertical interval above and below the approved injection zone, and the areas where potential migration of fluid or entrapment of migrated fluid could occur.

~~(B)~~ Reservoir fluid data for the injection zone, such as oil gravity and viscosity, water quality, presence and concentration of non-hydrocarbon components in the associated gas (such as hydrogen sulfide), and specific gravity of gas. Liquid quality analysis of the reservoir fluid shall be performed in accordance with Section 1724.7.2.

~~(C) (1)~~ Structural contour map drawn on a geologic marker at or near the top of each injection zone in the ~~project~~ area of review, indicating faults and any lateral containment features. If faults are identified, the operator must address whether or not the faults are capable of confining fluid to the approved injection zone, and any geologic features that could result in the migration of fluid out of the approved injection zone.

~~(D) (2)~~ Isopachous map of each injection zone or subzone in the ~~project~~ area of review.

~~(E) (3)~~ At least ~~one~~ two geologic cross sections in the area of review through at least three wells, including one injection well in the project area.

~~(F) (4)~~ Representative electric log to a depth below the deepest producing zone (if not already shown on the cross section), identifying all geologic units, formations, USDWs, freshwater aquifers, and oil or gas zones.

~~(3) (c)~~ An injection plan, including but not limited to:

- (A) Statement of primary purpose of the project.
- (B) ~~(1)~~ A map showing injection facilities.
- (C) ~~(2)~~ Maximum anticipated surface injection pressure (pump pressure) and Statement of the anticipated project duration, anticipated daily rate of injection, (by well), and anticipated cumulative net volume of fluid to be injected.
- (D) Identification of all wells that are part of the underground injection project, including injection wells, affected production wells, water source wells, observation or other wells, and any planned wells to the extent known. The depths of water source wells shall also be provided.
- (E) ~~(3)~~ Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the ~~intended~~ approved injection zone or zones of injection. In the event the Division, State Water Resources Control Board, or Regional Water Quality Control Board requires groundwater monitoring in relation to the underground injection project, or as a condition of project approval, the operator shall consult with the State Water Resources Control Board or Regional Water Quality Control Board and provide the Division with documentation and the results of such consultation.
- (F) ~~(4)~~ Method of injection.
- (G) ~~(5)~~ List of proposed cathodic protection measures for plant, lines, and wells, if such measures are warranted.
- ~~(6) Treatment of water to be injected.~~
- (H) ~~(7) Source~~ Identification of the source of the injection liquid and an analysis of the injection liquid, in accordance with Section 1724.7.2.
- ~~(8) Location and depth of each water source well that will be used in conjunction with the project.~~
- (4) All data supporting the determination under Section 1724.10.3 of the maximum allowable surface pressure for each injection well in the underground injection project, including all calculations and assumptions.
- (5) ~~(d)~~ Copies of letters of notification sent to offset operators.
- (6) ~~(e)~~ Any other data that, in the judgment of the Division, are pertinent and necessary for the proper evaluation of the underground injection project. Other data as required for large, unusual, or hazardous projects, for unusual or complex structures, or for critical wells. Examples of such data are: isogor maps, water-oil ratio maps, isobar maps, 3-D maps, computer geologic models, reservoir simulation results, equipment diagrams, and safety programs.

(b) When a new injection well is added to an underground injection project, the operator shall provide the Division with any new data relevant to the addition of the new well, and shall update data previously provided to the Division if relevant conditions have changed or if more accurate data has become available. The addition of a new well does not require the operator to submit data previously provided to the Division.

(c) ~~(f)~~ All data required under this section shall be submitted to the Division electronically. If requested by the Division, a hard copy of specified data shall also be submitted. All maps, diagrams, and exhibits required in subdivision (a) ~~Section 1724.7(a) through (e)~~ shall be clearly labeled, such as to scale and purpose, and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

(d) All data required under this section shall be submitted to the Division with a cover page including a statement that appropriate licensed professionals, whose signatures and stamps appears at the bottom of the page, are responsible for all data, if any, subject to the requirements of Business and Professions Code sections 6735, 7835, or 7835.1. If the operator determines that the submission does not include material subject to the requirements of Business and Professions Code sections 6735, 7835, or 7835.1, the cover page shall so indicate, and shall provide the name(s) and signature(s) of the individual(s) responsible for preparing the submission.

(e) The Division may accept data alternative to what is required under subdivision (a), provided that the operator demonstrates to the Division's satisfaction all of the following:

(1) It would be an unreasonable burden to provide the data specified in subdivision (a);

(2) The alternative data provided by the operator accomplishes the same purpose as the data it would replace;

(3) The underground injection project is, on whole, supported by data demonstrating that injected fluid will be confined to the approved injection zone, and that the underground injection project conforms to the requirements of this subchapter and will not cause damage to life, health, property, or natural resources.

AUTHORITY:

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

1724.7.1. Casing Diagrams

(a) Casing diagrams submitted under the requirements of this article shall include all of the following data:

- (1) Operator name, lease name, well number, and API number of the well;
- (2) Ground elevation from sea level;
- (3) Reference elevation (i.e., rig floor or Kelly bushing);
- (4) Base of freshwater;
- (5) Base of the lowermost USDW penetrated by the well;
- (6) Sizes, grades, connection type, and weights of casing;
- (7) Depths of shoes, stubs, and liner tops;
- (8) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, casing damage, and type and extent 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;
- (9) Information regarding associated equipment such as subsurface safety valves, packers, gas lift mandrels;
- (10) Diameter and depth of hole;
- (11) Identification of cement plugs inside casings, including locations of the top and bottom of cement plugs;
- (12) Identification of cement fill behind casings, including locations of the top and bottom of cement fill;
- (13) Type and weight (density) of fluid between cement plugs;
- (14) Depths and names of the formations, zones, and sand markers penetrated by the well, including the top and bottom of the injection zone for the underground injection project;

(b) Each casing diagram submitted to the Division shall be accompanied by documentation of the following:

- (1) All steps of cement yield and cement calculations performed;
- (2) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job completed in each well; and
- (3) The wellbore path, providing both inclination and azimuth measurements.

(c) 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 wellbores.

(d) Measured depth and true vertical depth shall be provided for all depths required under subdivision (a).

(e) In lieu of graphical casing diagrams, operators may satisfy the requirements of section 1724.7(a)(1)(C)(iii) by submitting a flat file data set containing all of the information described in this section.

AUTHORITY:

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

1724.7.2. Liquid Analysis

(a) Liquid analysis required under this article shall include testing for all of the following: total dissolved solids; total petroleum hydrocarbon; major cations (Ca, Mg, Na, K, Fe, Mn, Sr, B); major anions (Cl, SO₄, HCO₃, CO₃, Br, I); electrical conductance; pH; and temperature.

(b) The Division may require testing for additional constituents on a project-specific basis. Any additional constituents shall be listed in the Project Approval Letter for the project.

(c) To ensure the liquid analysis required under Sections 1724.7(a)(3)(H) and 1724.10(d) is representative of the liquid actually injected, the liquid to be analyzed shall be sampled after all additives (if any) are added to the liquid, and after all treatment or separation processes (if any).

(d) Liquid analysis required under this article shall be performed by a laboratory that is certified by the State Water Resources Control Board environmental laboratory accreditation program. The performing laboratory shall submit the data and analysis to the Division directly, using a digital format subject to Division specification.

AUTHORITY:

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

1724.8. ~~Data Required for Cyclic Steam Injection Project Approval.~~

~~The data required by the Division prior to approval of a cyclic steam (steam soak) project include, but are not limited to, the following:~~

- ~~–(a) A letter from the operator notifying the Division of the intention to conduct cyclic steam injection operations on a specific lease, in a specific reservoir, or in a particular well.~~
- ~~–(b) If cyclic steam injection is to be in wells adjacent to a lease boundary, a copy of a letter notifying each offset operator of the proposed project.~~

AUTHORITY:

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

1724.8 Evaluation of Wells Within the Area of Review

(a) An underground injection project shall not cause or contribute to the migration of fluid outside the approved injection zone, or otherwise have an adverse effect on the underground injection project or cause damage to life, health, property or natural resources. The following requirements apply, at minimum and subject to augmentation by the Division 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 injection zone:

(1) All wells within the area of review that are completed in or penetrating the injection zone for the underground injection project or a deeper zone, including directionally drilled wells that intersect the area of review in the injection zone or a deeper zone, shall be evaluated for the potential to allow fluid to migrate outside of the approved injection zone. The operator should identify, and the Division confirm, wells which may require integrity testing, well logging, or monitoring 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, the injection zone, or the oil and gas 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 plugged and abandoned wells within the area of review do 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 injection 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 specification of subdivision (a)(2), specify how the well(s) do not meet the requirements of subdivision (a)(2), and identify the bases for the Division's approval of the alternative demonstration.

AUTHORITY:

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

1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects

(a) The appropriate Division district deputy shall be notified of any anticipated changes in an underground injection project resulting in alteration of conditions originally approved inconsistency with the current conditions of approval, such as: increase in size expansion of the project, change of injection interval, or increase in maximum allowable surface injection pressure. Such changes shall not be carried out without prior written Division approval of the Division in accordance with Section 1724.6.

(b) ~~Notices of intention to drill, redrill, deepen, or rework, on current Division forms, shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well and whenever an existing well is converted to an injection well, even if no work is required on the well. In addition to the notice of intention that may be required under Public Resources Code section 3203, any addition of an injection well to an underground injection project, including the conversion of a well without alteration of casing and the resumption of injection in an injection well that has become an idle well as defined by Public Resources Code section 3008, requires the prior written approval of the Division in accordance with Section 1724.6.~~

(c) An injection report on a current Division form or in a digital-computerized format acceptable to the Division shall be filed with the Division on or before the 30th-last day of each month, for the preceding month.

(d) A representative chemical analysis of the liquid being injected, as specified in Section 1724.7.2, shall be made and filed with the Division whenever the source of injection liquid is changed, or as requested by the Supervisor Division. For the purposes of this subdivision, the source of injection is changed if a constituent source is added to or removed from the injection liquid, or if there is a significant change to the relative contribution of constituent sources.

(e) For each underground injection project that includes an injection well with open perforations located within five hundred feet of the screen or perforations of a water supply well, the operator shall provide to the Division in digital format on a yearly basis all of the information listed in paragraphs (1) through (4) of this subdivision. The applicability of this subdivision shall be based on a diligent search by the operator, including consultation of public records, and is not triggered by water supply wells owned or operated by the operator of the injection well. When applicable, the following information shall be provided:

(1) A water treatment process flow diagram depicting all physical and chemical treatment processes applied to the injection fluid, from its source to the injection well;

(2) The safety data sheet for each chemical additive emplaced in injection wells within the underground injection project, and for each chemical added to the fluid to be injected from the time the fluid is first obtained to the time it is injected;

(3) The project-aggregate volume or weight of each additive reported under subdivision (e)(2) of this section; and

(4) A brief description of the intended purpose of each additive reported under subdivision (e)(2) of this section.

~~(e) An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. A gauge or device used for injection pressure testing, which is permanently affixed to the well or any part of the injection system, shall be calibrated at least every six months. Portable gauges shall be calibrated at least every two months. Evidence of such calibration shall be available to the Division upon request.~~

(f) Well-specific injection pressure shall be continuously recorded at all times that a well is approved for injection by the Division, regardless of whether injection is actually occurring. On or before the last day of each month, operators shall report to the Division the highest instantaneous injection pressure for each injection well in the last preceding calendar month. Injection pressure records shall be maintained by the

operator as long as the well is approved for injection by the Division, and shall be provided to the Division upon request. Pressure recording devices shall be maintained in good working order and be calibrated as recommended by the manufacturer. Evidence of such calibration shall be available to the Division upon request. A Division-approved supervisory control and data acquisition (SCADA) or equivalent continuous real-time recording system, with automatic computer alarm notification, may be used to meet the requirements of this subdivision.

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

~~(h) (g)~~ Except as provided in this subdivision below, ~~all~~ All injection wells, ~~except steam, air, and pipeline-quality gas injection wells,~~ shall be equipped with tubing and packer set immediately above the approved ~~zone of injection zone~~ within one year after the effective date of this act. ~~New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion.~~ Injection wells equipped with tubing and packer may inject through the tubing, but not through the casing-tubing annulus unless the operator has written approval from the Division. Tubing and packer is not required for:

(1) Steamflood and cyclic steam injection wells;

(2) Any injection well for which the operator demonstrates based on documented evidence, and the Division agrees in writing, that:

(A) The well does not penetrate any USDW;

(B) The well is completed with more than one string of casing cemented to the satisfaction of the Division below the base of the lowermost USDW penetrated by the well; or

(C) There is other justification for a determination that all USDW, hydrocarbon, and high-pressure or other anomalous ~~and oil~~ zones can be protected without the use of tubing and packer.

~~Exceptions may be made when there is:~~

~~(1) No evidence of freshwater-bearing strata.~~

~~(2) More than one string of casing cemented below the base of fresh water.~~

~~(3) Other justification, as determined by the district deputy, based on documented evidence that freshwater and oil zones can be protected without the use of tubing and packer.~~

~~(h) Data shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notice from the Division. Project data shall be available for periodic inspection by Division personnel.~~

~~(i) To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior to conducting the test so that it may be witnessed by a Division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.~~

(i) Surface injection pressure of an injection well shall not exceed the maximum allowable surface pressure, as determined under Section 1724.10.3.

~~(j) A ~~mechanical~~ Mechanical integrity testing (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved injection zone or zones. Mechanical integrity testing shall consist of a two-part demonstration in accordance with Sections 1724.10.1 and 1724.10.2. The operator shall notify the appropriate Division district office at least forty-eight hours before performing any testing under Sections 1724.10.1 and 1724.10.2 so that Division staff may witness the operations, unless the Division approves shorter notice. Digital copies of surveys and test results shall be submitted to the Division within sixty days of the tests. Injection wells shall be constructed and maintained to allow for compliance with the testing described in Sections 1724.10.1 and 1724.10.2. Any injection well, including any cyclic steam injection well not actively injecting, that is not tested as required under Sections 1724.10.1 and 1724.10.2 shall automatically lose approval to inject, and subsequent written approval from the Division is required to reinitiate injection. An MIT shall consist of a two-part demonstration as provided in subsections (j)(1) and (2).~~

~~—(1) Prior to commencing injection operations, each injection well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks. Thereafter, the annulus of each 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.~~

~~—(2) When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity. The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer.~~

~~—(3) The second part of the MIT must be performed within three (3) months after injection has commenced. Thereafter, water-disposal wells shall be tested at least once each year; waterflood wells shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years. Such testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the appropriate Division district deputy. The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause.~~

~~—(4) The appropriate district office shall be notified before such tests/surveys are made, as a Division inspector may witness the operations. Copies of surveys and test results shall be submitted to the Division within 60 days.~~

(k) Injection wells and related facilities shall be monitored, as specified in the Project Approval Letter for each underground injection control project, in order to allow for the discovery and correction of abnormal operating conditions.

(l) Operators of cyclic steam injection wells shall maintain records in machine-readable format of the number, duration, and volume of fluid injected (in gallons per foot) of all injection cycles performed on each cyclic steam injection well. Such records shall be maintained as long as the well is approved for injection, and shall be provided to the Division upon request.

(m) ~~(k)~~ Additional requirements or modifications of the above requirements may be necessary to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are:

(1) Injectivity tests.

(2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by Division personnel.

(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by Division personnel.

(4) List of all observation wells used to monitor the project, indicating what parameters each well is monitoring (i.e., pressure, temperature, etc.), submitted to the Division annually.

~~—(5) List of all injection-withdrawal wells in a gas storage project, showing casing-integrity test methods and dates, the types of safety valves used, submitted to the~~

Division annually.

~~(5) (6)~~-Isobaric maps of the injection zone, submitted to the Division annually.

~~(6) (7)~~-Notification of any change in waste disposal methods.

AUTHORITY:

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

1724.10.1. Mechanical Integrity Testing Part One – Casing Integrity

(a) Casing Pressure Test at the Maximum Allowable Surface Pressure. Prior to commencing injection operations for the first time after a well is approved or reapproved by the Division for injection, each injection well shall pass a pressure test of the casing to determine the absence of leaks. Thereafter, the casing of each well shall 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 Division. Injection wells that were not subject to periodic casing pressure test requirements prior to the effective date of this regulation shall undergo the testing described in this subdivision within five years of the effective date of this regulation, and at least once every five years thereafter. 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.

Pressure testing under this subdivision shall conform to the following:

(1) If injection in the well is through tubing and packer, then the pressure test shall be of the casing-tubing annulus of the well.

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

(3) 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.

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

(5) Pressure tests shall be recorded and a calibrated gauge shall be used that can record a pressure with an accuracy within one percent. The pressure recording shall be submitted to the Division in an electronic format within 30 days.

(6) Pressure tests shall be conducted at an initial test pressure of at least the maximum allowable surface pressure, or 200 psi, whichever is greater.

(7) 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.

(8) 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.

(b) Alternative Pressure Monitoring. Subject to the Division's approval, for injection wells equipped with tubing and packer, operators may propose a pressure testing and annular pressure monitoring program, consistent with this subdivision, as a substitute for the pressure test described in subdivision (a).

(1) An operator's proposals for alternative annular pressure monitoring shall include the following information:

(A) All relevant information about the injection wells proposed to be monitored, including identifying information, size of the tubing and packer and setting depth, and date of the last tubing and packer reset;

(B) All relevant information about the proposed pressure monitoring system, including monitoring instrumentation specifications, computer data acquisition and storage system specifications, method and frequency of calibrating and otherwise confirming the working order of the monitoring system, and reporting protocols with a clear identification of reportable statistical deviations;

(C) Schedule of injection project implementation, including the known and anticipated addition or removal of wells from the project; and

(D) Technical justifications and reasons for requesting the alternative proposal.

(2) Alternative pressure testing and annular pressure monitoring programs are subject to the Division's approval, and the requirements and limitations stated in paragraphs (A) through (F), below.

(A) The well shall be pressure tested in accordance with all of the requirements in subdivision (a), except that pressure tests shall be conducted at an initial pressure of at least 500 psi, and subdivision (a)(6) shall not apply.

(B) In order to demonstrate ongoing mechanical integrity, the alternative annular pressure monitoring program shall adhere to the following conditions:

_____ (i) The casing-tubing annulus shall have a minimum of 100 psi pressure at all times, preferably with a nitrogen gas blanket at the surface to stabilize potentially large variations in pressure due to thermal expansion of incompressible fluid;

_____ (ii) There shall be an observable pressure differential (+/- 10% of the tubing pressure or at least +/- 50 psi) between the annular pressure and the tubing pressure; and

_____ (iii) There shall be no anomalous variances in the annular pressure. If there are significant pressure variations from the historic daily pressure readings, these shall be satisfactorily explained and documented as part of the operator's record of mechanical integrity.

_____ (C) The Division may consider proposals to modify the conditions of subdivision (b)(2)(B) on a case-by-case basis if the Division determines that the proposal will represent a stronger demonstration of ongoing mechanical integrity. Such proposals may include, but are not limited to, fail-safe systems, such as automatic casing pressure relief systems, and other back-up safety, shutdown, and pressure relief systems.

_____ (D) The casing-tubing annular pressure shall be measured and recorded at least as frequently as every five minutes with a pressure gauge having an appropriate range. The record of such documentation shall be made available to the Division upon request, including in digital form within one business day of a request from the Division. A Division-approved, operating supervisory control and data acquisition (SCADA) system, with automatic computer alarm notification, may be used to satisfy this requirement and is a preferred methodology.

_____ (E) The operator shall take immediate action to investigate any anomalous pressure incidents, as compared to historic daily readings. If there is any reason to suspect a leak, the operator shall take immediate action to prevent damage to public health, safety, and the environment. The operator shall provide immediate notice to the Division of any anomalous pressure incidents and the steps taken in response.

_____ (F) At any time, the Division may request a full casing pressure test as described in subdivision (a) of this section.

AUTHORITY:

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

1724.10.2 Mechanical Integrity Testing Part Two – Fluid Migration Behind Casing, Tubing or Packer

(a) In addition to testing under Section 1724.10.1, operators shall periodically test injection wells to demonstrate that there is no fluid migration behind the casing, tubing, or packer. This testing may be accomplished by any of the methods set forth in subdivisions (d) through (f) of this section, or other method approved by the Division (including modifications of the methods below when approved by the Division in writing). Operators shall obtain written approval from the Division regarding the testing method prior to performing the tests.

(b) Testing under this section is required within three months after injection has commenced for the first time after a well is approved or reapproved by the Division for injection. Commencing with the effective date of this section, subsequent testing under this section is required at least once every two years, with the following exceptions:

(1) Disposal injection wells shall be tested at least once a year;

(2) Cyclic steam wells equipped with tubing and packer are required to be tested at least once every three years;

(3) Steamflood injection wells equipped with tubing and packer are required to be tested at least once every five years;

(4) Additional testing is required following an unplanned variance in injection pressure of more than fifteen percent within a twenty-four-hour period; and

(5) Additional testing is required when requested by the Division, including as may be specified in the Project Approval Letter.

(c) On a project or well-specific basis, the Division may approve different testing frequencies from those specified in subdivision (b), and may approve alternative methods for demonstrating an absence of fluid behind the casing, tubing, or packer. Any approved variance shall be documented in writing and be based on specific factors identified in the writing, including but not limited to well construction, age of the well, demonstrated quality of cement encasing the well, quality of groundwater in the area, and operational considerations.

(d) Radioactive Tracer Survey. In addition to all other applicable federal, state, and local requirements, a radioactive tracer survey performed to satisfy the requirements of this section shall adhere to the following:

(1) Testing shall be conducted while injecting, and the operator shall ensure that adequate fluid 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 stable and as close to the maximum allowable injection rate as practical.

(2) If the injection well is equipped with a packer and there is no injection occurring above the packer, the casing-tubing annulus valve shall be open during testing and there shall be no fluid flow. If fluid flow is indicated, the test shall be discontinued and the casing-tubing annulus shall be evaluated.

(3) Gamma ray detector sensitivity shall be set in consideration of lithologic and other effects.

(4) A background gamma ray log over the interval to be tested shall be recorded before any radioactive material is introduced into the well.

(5) 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.

(6) The release of a slug of radioactive material shall be above the interval to be tested.

(7) 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.

(8) 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 shall be presented as a composite log on a common depth track. If means to differentiate the log traces are available, then no other presentation is required. If the traces cannot be differentiated on the composite log, then they shall also be presented individually.

(9) After any ejection of radioactive tracer into the wellbore, the slug of radioactive tracer material shall be followed until it has moved below the interval being tested. Any portion of the slug of radioactive tracer material that divides shall be accounted for.

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

(11) If a well is injecting at a rate consistent with that described in subdivision (d)(1), radioactively treated beads shall be introduced into the well and evaluated according to subdivision (d)(7) through (d)(10) of this section.

(12) Steam injection wells shall be tested using an inert gas tracer.

(e) Temperature Survey. A temperature survey performed to satisfy the requirements of this section shall adhere to the following:

(1) The well shall be taken off injection at least twenty-four hours but not more than forty-eight hours prior to performing the temperature survey, unless an alternate duration has been approved by the Division.

(2) The temperature logging tool shall be calibrated to the manufacturer's recommendations or as otherwise requested by the Division.

(3) The well shall be logged from the surface downward, lowering the tool at a rate of no more than thirty feet per minute or a faster rate approved in advance by the Division based upon the operator's demonstration that the faster rate will yield data of at least equivalent quality.

(4) If the well has not been taken off injection for at least twenty-four 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.

(5) The log data shall be provided to the Division electronically in LAS, ASCII, or other format that is acceptable to the Division.

(f) Noise Log. A noise log performed to satisfy the requirements of this section shall adhere to the following:

(1) Noise logging may be carried out while injection is occurring.

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

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

(4) Noise measurements shall be taken at intervals of ten feet through the first fifty feet above the injection interval and at intervals of twenty 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, if any; and

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

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

- (6) A vertical scale of one or two inches per 100 feet shall be used.
- (g) The operator shall take immediate action to investigate any anomalies encountered during testing required under this section. If there is any reason to suspect fluid migration, the operator shall take immediate action to prevent damage to public health, safety, and the environment, and shall notify the Division immediately.

AUTHORITY:

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

1724.10.3. Maximum Allowable Surface Pressure

(a) The maximum allowable surface injection pressure for an injection well shall equal the true vertical depth of the shallowest portion of the well open to the injection zone multiplied by the difference between the injection gradient and the injection fluid gradient ($MA SP = (IG - IFG) * TVD$). The injection gradient used for this calculation shall be the product of the fracture gradient as determined under subdivision (b) or (c), multiplied by 0.95, or other multiplier subject to Division approval on a well-specific basis that more appropriately accounts for factors such as friction loss. The Division may approve a higher maximum allowable surface injection pressure based on a demonstration by the operator that the higher maximum allowable surface injection pressure is needed for effective resource production, that injected fluid will remain confined to the approved injection zone, that the higher pressure does not initiate new fractures or propagate existing fractures outside the approved injection zone, and that the higher pressure will not otherwise threaten life, health, property, and natural resources.

(b) Subject to the Division's approval, an estimated baseline fracture gradient may be used for determining the maximum allowable surface injection pressure for all injection wells within a given area. An estimated baseline fracture gradient shall be supported by representative step rate tests, or other testing or geologic data, demonstrating to the Division's satisfaction that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area where the estimated baseline fracture gradient will be used.

(c) If an injection well is not within the area of an approved estimated baseline fracture gradient, or if the operator seeks to establish a well-specific fracture gradient above the

estimated baseline fracture gradient, then the fracture gradient shall be determined by performing a step rate test on the injection well or by another method approved by the Division to effectively determine the fracture gradient.

(d) Step rate tests conducted to satisfy the requirements of this section shall meet the following requirements:

(1) Before commencing the test, the well shall be shut in until the bottom-hole pressures approximate shut-in formation pressures. If the shut-in well flows to the surface, then the static surface pressure shall be read and recorded.

(2) The operator may determine the appropriate length of time to conduct each step of the step rate test, provided that each of the steps is conducted for the same amount of time and a stabilized pressure value is obtained within each step. If steps are conducted for differing lengths of time or if a step does not yield a stabilized pressure value, then the Division may deem the step rate test inconclusive. Suggested step durations are thirty minutes if the formation has a permeability of more than ten millidarcies, and sixty minutes if the formation has a permeability of ten millidarcies or less.

(3) The first three steps of the step rate test shall be below the fracture gradient.

(4) Real-time downhole pressure recording shall be employed, unless an alternative has been approved by the Division.

(5) Bottom-hole pressure shall be recorded at a zero injection rate for at least one full time step before the first step of the step rate test and before one full time step after the last step of the step rate test.

(6) Step rate test data reported under Section 1724.7(a)(4) shall include the injection rate, bottom-hole pressure, surface pressure, pump rate volume, and time recorded continuously at a rate of every one second during the step rate test. The step rate test data submitted to the Division shall be raw and unaltered.

(7) Operators shall provide the appropriate Division district office with at least twenty-four hours of advance notice, or other period of advance notice acceptable to the district office, prior to conducting a step rate test for purposes of this section.

AUTHORITY:

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

1724.11. Surface Expression Prevention and Response

(a) Underground injection projects shall not result in any surface expression.

(b) The following requirements apply to all underground injection projects that the Division determines have the potential to cause a surface expression, and to all underground injection projects that involve the application of steam to a diatomaceous formation unless it has been demonstrated to the Division's satisfaction on a project-specific basis that surface expressions are not a concern for that project:

(1) The operator shall develop and employ a sub-surface injection-production mass balancing surveillance plan utilizing a continuous tilt meter array, or other ground monitoring system approved by the Division, and implement a real-time pressure/flow monitoring system that will give adequate warning to prevent surface expressions.

(2) The operator shall have staff on site twenty-four hours a day to monitor underground injection project operations.

(3) The operator shall conduct daily visual inspections of all wells and production facilities associated with the underground injection project.

(4) The operator shall continuously monitor steam injection rates and pressures. If, over any twenty-four hour period, injection pressures show a variance of more than fifteen percent or the injection rate shows a variance of more than thirty percent, the operator shall immediately notify the Division and conduct a diagnosis within twelve hours, including but not limited to:

(A) Confirmation of data.

(B) Inspection of wells and facilities associated with the anomaly.

(C) Review of overall system operations.

(D) Evaluation of ground monitoring data.

(5) If a diagnosis conducted pursuant to subdivision (b)(4) indicates there is a threat of steam leaving the approved injection zone, the operator shall immediately cease injection in wells that have an injection interval within 500 feet of any injection interval of the well that experienced the variance. Injection may resume once the Division is satisfied that the threat has been resolved and the appropriate Division district deputy has provided the operator with written approval to restart injection.

(c) Operators shall immediately notify the Division if a surface expression occurs, increases in flow or size, or reactivates within the operator's lease. The notification to the Division shall include a list of all injection wells with an injection interval 300 feet or less from any point of the surface expression, ground monitoring data for no less than

fourteen days immediately preceding the occurrence, and additional data as may be requested by the Division.

(d) The operator shall immediately cease injection in a well if there is a surface expression within 300 feet of the well's injection interval, or if there is a surface expression that has been flowing for more than five days within 600 feet of the well's injection interval. If a surface expression continues to flow for more than ten days, the Division will determine an expanded radius around the surface expression within which injection shall cease. The Division will determine the expanded radius based on consideration of the flow rate of the surface expression, geologic factors, and operational parameters.

(e) The Division may direct injection to cease at any injection well, regardless of its distance from a surface expression, if the Division finds reason to believe that the injection well is causing or contributing to a surface expression.

(f) All wells that have ceased injecting pursuant to subdivisions (d) or (e) shall be prominently marked and tagged in the field to indicate that injection is not occurring.

(g) Wells that have ceased injecting pursuant to subdivisions (d) or (e) may not resume injection until the Division is satisfied that the cause of the surface expression has been determined and remediated and the appropriate Division district deputy has provided the operator with written approval to restart injection. With the advance written approval of the Division, the operator may be allowed to conduct limited injection for purposes of identifying the cause of a surface expression.

(h) If a surface expression discharges oil in a reportable quantity, then it shall be immediately reported as an oil spill to the Division and the California Governor's Office of Emergency Services at (800) 852-7550.

(i) Until there has been an evaluation by a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code, and the Division is satisfied that the surface expression has stopped flowing and the area is safe for reentry, the area where a surface expression has occurred shall be cordoned off to restrict access to the surface expression. Additionally, the operator shall place prominent "Danger" or "Warning" signs, compliant with section 3340 of Title 8 of the California Code of Regulations, near (as safety dictates) the surface expression.

(j) The volume of any oil removed from the site of the surface expression shall be measured and reported to the Division, consistent with Public Resources Code section 3227, using a unique identifier assigned by the Division.

AUTHORITY:

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

1724.12. Surface Expression Containment

(a) The following requirements apply to the installation and use of surface expression containment measures, if any:

(1) The operator shall provide the Division with notice of construction of a surface expression containment measure to allow the Division to observe and document the installation.

(2) Surface expression containment measures shall be designed by, and construction shall be supervised by and signed off by a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code. All surface expression containment measures shall be included in the operator's Spill Contingency Plan required under Section 1722.9, shall meet all federal, state and local requirements, and shall ensure that surface expressions do not threaten surface water or USDWs.

(3) Upon completion of a surface expression containment measure, the licensed engineer shall provide a signed written report to the Division indicating whether the surface expression containment measure was constructed as designed and will safely and effectively contain or collect the flow from the surface expression.

(4) The operator shall continuously monitor and record the rate of flow of the surface expression and monitor the containment measures. The operator shall immediately notify the Division if the surface expression increases in flow or size, reactivates, or moves, or if there is any indication that the effectiveness of the surface expression containment measure has diminished.

(5) The operator shall map and prominently mark in the field all surface expression containment measures, and shall restrict access to such containment measures.

AUTHORITY:

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

1724.13. Universal Operating Restrictions and Incident Response

(a) The operator shall cease injection into the affected injection well and immediately notify the Division if any of the following occur:

(1) The operator has not performed mechanical integrity testing on the well as required by Section 1724.10(j) or the notification and results required under Section 1724.10(j) have not been provided to the Division;

(2) The well failed a mechanical integrity test required by Section 1724.10(j) or there is any other indication that the well lacks mechanical integrity or is otherwise incapable of performing as approved by the Division;

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

(4) There is any indication that fluids being injected into the well are not confined to the approved injection zone;

(5) There is any indication that damage to life, health, property, or natural resources, or loss of hydrocarbons is occurring by reason of the injection;

(6) The operator has not provided information regarding the well as required under Public Resources Code section 3227;

(7) The well has become an idle well as defined by Public Resources Code section 3008, subdivision (d); or

(8) The Division instructs the operator in writing to suspend injection.

(b) The operator shall comply with all operational and remedial directives of the Division related to the reason for ceasing injection, and shall not resume injection into the well without subsequent written approval from the Division.

(c) Each day that injection occurs into an injection well in violation of this section shall be considered a separate violation.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3106 and 3236.5, Public Resources Code.

1724.14. Monitoring and Evaluation of Seismic Activity in the Vicinity of Disposal Injection

(a) From commencement of injection activity, the operator shall monitor on a daily basis the California Integrated Seismic Network for indication of any earthquake of

magnitude 2.7 or greater with a hypocenter occurring within a spherical radius of one mile of the injection interval of any active disposal injection well.

(b) If an earthquake of magnitude 2.7 or greater is identified under subdivision (a), the following requirements apply:

(1) The operator shall notify the Division within twenty-four hours and inform the Division when and where the earthquake occurred, and all wells that are subject to subdivision (a). The epicenter and hypocenter shall also be reported to the Division.

(2) The Division, in consultation with the operator and the California Geological Survey, will conduct an evaluation of the following:

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

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

(C) Whether the mechanical integrity of any well, facility, or pipeline has been compromised as a result of the seismic activity.

AUTHORITY:

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

Subchapter 1.1. Offshore Well Regulations

Article 3. Regulations

1748. ~~Waste Disposal and Injection Projects~~ Underground Injection Control

~~Disposal and Underground injection projects, as defined in Section 1720.1(m), including offshore underground injection projects, are subject to the provisions of Section 1748.4 through 1748.3~~ Subchapter 1, Article 4.

AUTHORITY:

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

1748.2. Injection Projects

~~All subsurface injection projects require prior approval of this Division. An operator requesting approval to inject fluid into any subsurface strata must provide certain technical data regarding the project. This information must be submitted sufficiently in advance to enable the Division to evaluate fully the possible effects of the project upon any oil, gas, or fresh water reservoirs that may be present. The completeness and accuracy of the following data filed will have a bearing on this Division's decision to approve or disapprove the project.~~

~~(a) One or more geologic cross sections through the injection well at a scale that will clearly show the following:~~

~~(1) The injection well, or wells.~~

~~(2) A sufficient number of producing wells to show the geologic structure and stratigraphic relationship.~~

~~(3) Casing detail of all wells shown.~~

~~(4) The zone or zones to be injected into, other geologic units present, and the base of any fresh water aquifer.~~

~~(5) Location of any existing oil-water and oil-gas interfaces in or above the injection zone.~~

~~(6) The intervals of all geologic formations present.~~

~~(7) Fault block designations.~~

~~(b) A representative electric log from the surface to a depth below the producing zones (if not already shown on the cross section), identifying all geologic units, formations, oil or gas zones, and fresh water aquifers.~~

~~(c) Structural contour maps of markers at or near the top of each proposed injection zone showing the following:~~

~~(1) The location of the proposed injection well or wells, together with directional plots, bottom-hole locations, well status symbols, and zones open to production for all wells bottomed within the affected area.~~

~~(2) Reservoir characteristics such as pinchouts, permeability barriers and faults.~~

~~(3) Mineral lease boundary lines and fault block designations.~~

~~(4) Lines of cross sections.~~

~~(5) Lines showing original oil-water and oil-gas contacts.~~

~~(d) Letter containing engineering and geologic details of the project, in duplicate, including:~~

- ~~—(1) Primary purpose.~~
- ~~—(2) Reservoir characteristics of the injection zone; i.e., porosity, permeability, thickness (net and gross), present temperature and pressure, and present oil, gas, and water saturation.~~
- ~~—(3) Casing diagrams, including cement plugs and cement fill behind casing, of all idle, plugged and abandoned, or deeper zone producing wells within the area affected by the project.~~
- ~~—(4) Source and analysis of the injection water and analysis of the water in the injection zone.~~
- ~~—(5) Treatment of the water to be injected.~~
- ~~—(6) Method of injection, i.e., through casing, tubing, tubing with packer, between strings.~~
- ~~—(7) Maximum daily rate of injection, by well or wells.~~
- ~~—(8) Maximum surface injection pressure anticipated (pump pressure).~~
- ~~—(9) Precautions taken, or to be taken, to insure that the injected fluid is confined to the injection zone and to the area controlled by the operator.~~
- ~~—(10) Protective methods used, if any, on injection lines and well(s), i.e., cathodic, etc.~~
- ~~—(e) Copies of letters of notification sent to neighboring operators.~~
- ~~—(f) Other data as required for large, unusual, or hazardous projects, for unusual or complex structures, for sensitive locations, etc. Examples: Isopach map, IsoGOR map, water-oil ratio map, IsoBAR maps, equipment diagrams, and safety precautions.~~

~~Note: Authority cited: Section 3013, Public Resources Code. Reference: Section 3301, Public Resources Code.~~

1748.3. Injection Requirements

- ~~—(a) Appropriate forms furnished by the Division for proposal to drill or rework shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well, or whenever an existing well is to be converted to an injection well, even if no work is required.~~
- ~~—(b) An injection report on a Division form shall be filed with this Division in duplicate on or before the tenth day of each month, for the preceding month.~~

- ~~–(c) A chemical analysis of the fluid (or gas) to be injected shall be made and filed with this Division at least every two years, whenever the source of injection fluid is changed, or as requested.~~
- ~~–(d) An accurate, operating pressure gauge or chart shall be maintained at the wellhead at all times.~~
- ~~–(e) Fluid injection profile surveys shall be required for all injection wells within one month after injection has commenced, at least once every year thereafter for all high-pressure or high-volume injection wells, after any significant anomalous rate or pressure change, or as requested by the Division, to confirm that the injection fluid is confined to the proper zone.~~
- ~~–(f) Sufficient data shall be maintained to show performance of the project and to establish that no damage is occurring because of excessive injection pressure. These data shall be available for periodic inspection by personnel from this Division.~~
- ~~–(g) Injection shall cease upon written notice from the Division if any evidence of damage is observed by the Division or in its opinion is occurring.~~
- ~~–(h) Additional requirements or modification of the above requirements may be necessary to fit individual circumstances.~~