UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

INITIAL STATEMENT OF REASONS

The Department of Conservation (Department) proposes to add, amend, and delete sections within California Code of Regulations, title 14, division 2, chapter 4, subchapter 1, articles 2 and 4, and subchapter 1.1, article 3. In particular, the Department would add sections 1720.1, 1724.7.1, 1724.7.2, 1724.8, 1724.10.1, 1724.10.2, 1724.10.3, 1724.11, 1724.12, 1724.13, and 1724.14; amend sections 1724.6, 1724.7, 1724.10, and 1748; and delete existing sections 1724.8, 1748.2, and 1748.3.[1]

INTRODUCTION AND BACKGROUND

Regulation of Underground Injection Wells Associated with Oil and Gas Production

The Division of Oil, Gas, and Geothermal Resources (Division), within the Department, supervises the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells. The Division carries out its regulatory authority under a dual legislative mandate to encourage the wise development of oil and gas resources, while preventing damage to life, health, property, and natural resources, including underground and surface waters suitable for domestic or irrigation purposes. (See Pub. Resources Code, § 3106.) In addition to wells that draw up hydrocarbons from underground reservoirs, the California oil and gas industry also uses other wells to inject fluids into underground formations. These injection wells are among the wells the Division regulates.

Injection wells have been an integral part of California's oil and gas operations for nearly 60 years. There are approximately 55,000 oilfield injection wells operating in California. These include enhanced oil recovery (EOR) wells used to increase oil recovery through sustained injection or reinjection of large volumes of fluids, and wells devoted to the disposal of the "produced water" that emerges from hydrocarbon deposit areas simultaneously and commingled with the produced hydrocarbons. About 75 percent of the roughly 600,000 barrels of oil produced daily in California (35 percent of California's daily petroleum use) results from the use of EOR injection methods.

Injection wells also function as a disposal method for large volumes of water that are drawn-up along with the hydrocarbons. Due to the maturity of California's oil fields, every

[1] Unless otherwise specified, references in this document to a "section" are references to sections of California Code of Regulations, title 14. Unless otherwise specified, references in this document to a "proposed section" are references to a section of California Code of Regulations, title 14, as it would be added or amended by this rulemaking action.

barrel of oil extracted from underground is comingled with over 15 barrels of water (on average). After the oil is separated, operators must dispose of the immense volumes of water in order to continue the production process. Of the residual water, roughly two-thirds is returned to oil-bearing reservoirs for enhanced production and reservoir pressure balance. The remaining one-third may be cleaned and blended with other water for use in agriculture, support of habitat, or miscellaneous oilfield use. Additionally, approximately 1,800 disposal injection wells enable the underground disposal of any remaining produced water not put to some other use.

The Division regulates injection wells associated with California oil and gas production to prevent damage to life, health, property, and natural resources. The Division's regulations specific to underground injection wells, often referred to as the underground injection control, or "UIC," regulations, are located in sections 1724.6 through 1724.10. In general, these requirements include the need for Division approval to begin injection operations, the submission of geologic and engineering data necessary to evaluate injection projects, well construction requirements, and periodic testing to demonstrate the mechanical integrity of each injection well. Many of the UIC regulatory requirements revolve around the review standard of ensuring that the injection fluid will be confined to the approved injection zone and not migrate into a zone where it could degrade valuable groundwater resources.

The Division's staff is comprised of engineers and geologists with education and experience in the field of oil and gas exploration and production. Many of the Division's staff are licensed in their respective fields, and most have extensive regulatory and industry backgrounds. The range and depth of expertise within the Division facilitates a thorough and comprehensive approach to regulating all aspects of oil and gas production operations, including underground injection operations associated with oil and gas production.

<u>Division Primacy to Enforce an Underground Injection Control Program Pursuant to the Federal Safe Drinking Water Act</u>

Enacted in 1974, the federal Safe Drinking Water Act directed the United States Environmental Protection Agency (US EPA) to develop federal standards for the protection of the nation's public drinking water supply. Section 1425 of the Safe Drinking Water Act allows states to obtain primary enforcement responsibility (often referred to as "primacy") to regulate the underground injection of fluids associated with oil and gas production through their own state UIC programs. To obtain primacy, a state must demonstrate to US EPA's satisfaction that the state UIC program meets certain minimum requirements set forth in the Safe Drinking Water Act and represents an effective program to prevent injection that endangers underground sources of drinking water. (See 42 U.S.C., § 300h–4(a).) Once US EPA approves a state UIC program, the state has primary responsibility to regulate underground injection within its jurisdiction. In such cases, the state and US EPA enter into a Memorandum of Agreement (Primacy Agreement), which may include other terms, conditions, or agreements relevant to the administration and enforcement of the state's regulatory program. (See 40 C.F.R. § 145.25(a).)

US EPA granted primacy to the Division through a Memorandum of Agreement between US EPA and the Division, dated September 29, 1982.[2] Concurrent with the Division's state law mandates, the primacy delegation commits the Division to several regulatory objectives for underground injection wells. These objectives include two-part mechanical integrity testing for injection wells, evaluation of other wells within a specified "area of review" around injection wells prior to regulatory approval of injection projects, and protection of underground sources of drinking water (generally, groundwater aquifers with water containing less than 10,000 milligrams per liter total dissolved solids).

<u>Need to Update the Division's UIC Regulations</u>

In 2011, at the Division's request, the US EPA conducted an audit of the Division's UIC program to assess compliance with the requirements of the primacy delegation under the federal Safe Drinking Water Act. The audit found the Division lacking in the implementation of a number of requirements, including consistent area of review analyses, accurate determination of fracture gradients for injection projects, and enforcement of appropriate maximum allowable surface injection pressures.

Also in 2011, an oil industry employee tragically died when the ground beneath him gave way and he fell into a pool of heated fluid. The pool, known as a "surface expression," was in part the result of nearby cyclic steam injection operations. The Division's current regulations do not specifically address or prohibit surface expressions caused by injection operations, although the existence of a surface expression is indicative of injection being performed at rates and pressures above safe levels and that injection is not confined to the approved injection zone.

Partially a result of the US EPA audit and the tragic oilfield death, the Division re-examined its UIC program. Correctional efforts have involved internal policy shifts, hiring of additional staff, and stronger internal oversight of permitting and enforcement practices throughout the Division's district offices. In addition, this rulemaking to update the Division's UIC regulations with improved standards that better align with the commitments expressed in the Primacy Agreement and with modern industry practices is central to the program overhaul.

The Division's existing regulations require considerable case-by-case interpretation to identify appropriate project-specific requirements. Over time, this has led to a general lack of transparency and inconsistent application of requirements, and, in some cases, aging regulatory constructs that have not kept up with changing oil production methods

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[2] Available at: http://www.conservation.ca.gov/dog/general_information/Documents/MOA_DOG_USEPA_UIC.PDF.

and advancements in the understanding of threats to health, safety, and the environment. One industry practice that has outpaced the Division's existing regulations is cyclic steam injection. While the use of cyclic steam injection wells increased significantly beginning in the 1990s, ambiguities in the Division's existing regulations have enabled excessive variability in the Division's regulation of such wells, with some wells avoiding certain UIC requirements. Other concerns this present rulemaking is intended to address include outdated or otherwise inadequate data to support injection project performance, inadequate data (such as casing diagrams) to support area of review analyses, lack of specificity surrounding acceptable testing protocols, and obscure project approval documentation. Each of these problems, as well as how the proposed regulations would address them, is discussed below in relation to the specific amendments.

Public Input Efforts Preceding This Rulemaking

In developing the proposed regulations, the Division did extensive public outreach to solicit input on the substance and economic impacts of the requirements. The Division conducted preliminary scoping workshops, circulated two pre-rulemaking drafts of the proposed regulations, conducted public workshops and targeted stakeholder meetings to solicit input on the drafts, and surveyed operators for input on direct costs.

Initially, the Division conducted three public workshops to solicit input on the scope and direction of this rulemaking effort. On August 17, 2015, the Division released a Notice of Workshops on the Development of Updates to the Division's Underground Injection Control Regulations. The notice invited participation in the workshops as well as written input. Enclosed with the Notice was a Discussion Paper that identified the Division's regulatory goals for the UIC rulemaking effort and encouraged interested parties to identify themselves for participating in the rulemaking effort. The workshops were held on September 9, 2015 in Los Angeles, September 10, 2015 in Ventura, and September 15, 2015 in Bakersfield. Written comments were received until September 15, 2015.

Much of the Division's public outreach centered on soliciting input on two pre-rulemaking drafts of the regulations. On January 21, 2016, the Division made a pre-rulemaking draft available for public comment, soliciting public input through March 4, 2016. On April 26, 2017, the Division made a second pre-rulemaking draft available for public comment, soliciting public input through June 26, 2017. During that time, the Division conducted a public workshop in Bakersfield to discuss the second pre-rulemaking draft.

Since the summer of 2017, the Division has carefully reviewed public input, and input from the State Water Resources Control Board, Regional Water Quality Control Boards, and the US EPA. These proposed regulations have evolved significantly during this pre-rulemaking public process.

ANTICIPATED BENEFITS (GENERALLY)

The anticipated benefits of each proposed section or amendment to an existing section are discussed specifically below. In general, however, this rulemaking action will modernize, clarify, and augment the regulatory standards applicable to underground injection operations associated with oil and gas development in California. The proposed action will also increase transparency regarding the Division's regulatory standards and expectations for underground injection projects. This will aid the Division in implementing its statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

SPECIFIC PURPOSE, RATIONALE AND BENEFITS

1720.1. Definitions

A number of key terms used in the regulations require definition because they are used to convey a specific meaning, are subject to more than one interpretation, or are technical terms that are not commonly known. The purpose of proposed section 1720.1 is to clarify the meaning of ambiguous terms, promote transparency, and support consistent application of the regulations. Proposed section 1720.1 is necessary to ensure that those who are subject to the Division's underground injection control regulations are able to understand and interpret the regulations correctly and consistently.

"Area of review" is defined as a certain area around each injection well that must be studied and monitored in relation to the underground injection project, particularly with respect to the potential for injection fluid to migrate outside of the injection zone. Defining the term "area of review" is necessary to give specific meaning to its usage elsewhere in the regulations.

Consistent with the federal Safe Drinking Water Act regulations, the area of review is defined as either the calculated distance that injected fluid may migrate (in the federal regulation this is referred to as the "zone of endangering influence"), or a fixed one-quarter mile radius. (See 40 C.F.R. § 146.6.) The definition provides that the operator should propose an appropriate area or review for a given injection well, but that the Division may adjust the operator's proposed area review based on project-specific data and factors.

This definition of "area of review" will help ensure that the standard the Division applies to UIC project reviews is aligned with the federal Safe Drinking Water Act standard and that the Division may avoid use of a quarter-mile fixed radius in circumstances where it would not accurately reflect the potential scope of injection fluid migration.

"Cyclic steam injection well" is defined as a certain kind of injection well. Defining the term is necessary to give specific meaning to its usage elsewhere in the regulations. The

Division believes the definition given for this term is consistent with the prevailing understanding of the regulated community.

“Disposal injection well” is defined as a certain kind of injection well. Defining the term is necessary to give specific meaning to its usage elsewhere in the regulations. The Division believes the definition given for this term is consistent with the prevailing understanding of the regulated community.

“Fluid” is defined as liquid, gas, or steam. The definition is consistent with the dictionary definition of the term, but is necessary because “fluid” is frequently colloquially understood to mean only liquid.

“Freshwater” is defined as water that contains less than 3,000 milligrams per liter of total dissolved solids. Although not defined in the Division’s existing regulations, the Division has a long-standing practice of using this term and definition in the exercise of its regulatory authority. At least in part, this practice has been guided by the policy for designation of sources of drinking water set forth in State Water Resources Control Board Resolution No. 88-63. Adding this definition is necessary to give clear meaning to an otherwise potentially ambiguous term used in the proposed regulations. The specificity provided by this definition will improve the transparency of the Division’s regulatory practices.

“Injection well” is defined to give specific meaning to the class of wells subject to the Division’s underground injection control regulations. The Division believes the definition given for this term is consistent with the prevailing understanding of the regulated community.

“Injection zone” is defined as a specified space where injected fluid is anticipated to be located. The definition is necessary to give specific meaning to an otherwise ambiguous term used throughout the Division’s regulations. Where the regulations use the term, the concern is defining the scope of the area where injected fluids might migrate, as opposed to just defining the scope of the formation or strata where fluid is initially injected. For this reason, “injection zone” is defined to possibly include more than one formation or strata.

“Mechanical integrity” is defined to support consistent interpretation of a standard applicable to wells, which is used elsewhere in the regulations. The definition is necessary because the term may be subject to more than one interpretation and is a key term for other requirements, including the requirements for mechanical integrity testing.

The term **“mg/l TDS”** is defined as a short-hand term for total dissolved solids and the applicable unit of measure. The definition is necessary to state, in non-abbreviated form, the meaning of the term used elsewhere in the Division’s proposed regulations.

“Steamflood injection well” is defined as a certain kind of injection well. Defining the term is necessary to give specific meaning to its usage elsewhere in the proposed regulations. The Division believes the definition given for this term is consistent with the prevailing understanding of the regulated community.

"Surface expression" is defined as a certain kind of flow, movement, or release to the surface caused by injection operations. The definition is necessary because the term may be subject to more than one interpretation, and because other portions of the proposed regulations include requirements for surface expressions and surface expression containment.

"Surface expression containment measure" is defined as an engineered measure to contain or collect the fluids from surface expressions. The definition, which includes several examples of surface expression containment measures, is necessary because the term may be subject to more than one interpretation and because other portions of the proposed regulations include requirements for surface expression containment measures.

"Underground injection project" is defined for the description of the range and kind of operations that are subject to the Division's underground injection control regulations. The definition, which includes examples of underground injection projects, is necessary to avoid ambiguity about the kinds of operations that trigger applicable requirements.

"Underground source of drinking water" or **"USDW"** is defined as an aquifer that has not been exempted in accordance with federal regulations and either supplies a public water system or meets a specific quantity and quality threshold. The definition closely tracks the definition of the same term in Section 144.3 of Title 40 of the Code of Federal Regulations. The definition in the proposed regulations defines "public water system" by reference to the definition found in the Health and Safety Code to avoid inconsistency. It also includes the definition of an "exempted aquifer," which is not found in the federal definition of "USDW," but is found elsewhere in the federal regulations. The Division consulted with the US EPA to ensure that the definition in the proposed regulation is harmonious with the definition in federal regulation. The definition is necessary to give a specific meaning to the term, which is used elsewhere in the proposed regulations.

"Waterflood injection well" is defined as a certain kind of injection well. Defining the term is necessary to give specific meaning to its usage elsewhere in the proposed regulations. The Division believes the definition given for this term is consistent with the prevailing understanding of the regulated community.

"Water supply well" is defined as a well that provides water for domestic, municipal, industrial, or irrigation purposes, other than a well associated with oil and gas operations. Defining the term is necessary to give specific meaning to its usage elsewhere in the proposed regulations.

Article 4. Underground Injection Control

Within title 14, chapter 4, subchapter 1, the proposed rulemaking would create a new article 4, titled, “Underground Injection Control,” in order that the proposed regulations may be easily and accurately referred to as the “Underground Injection Control regulations,” because the regulations governing underground injection projects are already commonly referenced.

1724.6. Approval of Underground Injection and Disposal Projects

Under existing sections 1714 and 1724.6, operators must have written approval from the Division prior to commencing injection operations. The existing regulations are general and lack specificity as to application and approval mechanisms for injection operations. In 2015, the Division conducted an internal review of its UIC program (hereinafter referred to as the 2015 UIC Program Assessment Report) and found many Project Approval Letters incomplete and unclear.[3] The proposed section is necessary and intended to address these problems by ascribing greater meaning to the Project Approval Letter as the document that specifically identifies, on a project-specific basis, the terms and conditions of project approval.

Proposed section 1724.6, **subdivision (a)**, would promulgate in regulation the Division’s long-standing practice of conveying approval for injection projects through Project Approval Letters. The amendment would also clarify and memorialize the existing expectation that proponents of injection projects must submit the data specified in section 1724.7 in addition to any other data the Division deems necessary. These amendments will provide greater standardization and clarification regarding the Division’s approval mechanism for injection projects.

Proposed section 1724.6, **subdivision (b)**, would explain that the Project Approval Letter will be used to identify basic facts about the injection project, and also to convey the Division’s conditions of approval. These conditions, which operate as limitations to the scope of Division approvals, are typically included in individual Project Approval Letters as part of the Division’s current practice. The amendment would commit the Division’s regulatory practice to regulation, and ensure that Project Approval Letters are informative and enforceable documents delineating the scope and limitations of underground injection projects.

Proposed section 1724.6, **subdivision (c)**, would provide that subsequent Division approval is required for any modification of a project. Under existing regulatory practices, this limitation is typically conveyed in Project Approval Letters. The subdivision is

[3] *Underground Injection Control Program Report on Permitting and Program Assessment: Reporting Period of Calendar Years 2011-2014* (Oct. 2015), at p. 15.

necessary to ensure that the limitation applies to all projects, regardless of whether it is stated in the Project Approval Letter.

Proposed section 1724.6, **subdivision (d)**, would provide that the Division will periodically review injection projects to ensure that they remain consistent with their Project Approval Letters and to ensure that the approval conditions are effectively preventing damage to life, health, property, and natural resources, consistent with the Division's statutory mandate under Public Resources Code section 3106. The subdivision would also make clear that approval of injection projects is subject to the Division's ongoing discretion throughout the life of the project.

Proposed **subdivision (e)** would dovetail subdivision (d) in making clear that the Division may order immediate cessation of injection operations upon written notice if the Division determines that a project is being operated inconsistently with the terms of the Project Approval Letter or otherwise conflicts with the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources. While these amendments are consistent with the Division's current practices and legal authorities, identifying in regulation the Division's broad and ongoing discretion over injection project approvals is necessary to set appropriate operator expectations, and to clarify the Division's continued oversight over existing injection projects.

Proposed section 1724.6, **subdivision (f)**, would require the new operator of a transferred injection project to meet with the Division within 60 days after the transfer. The purpose of this requirement is to ensure new operators are fully apprised of the operating conditions and other parameters of Project Approval Letters. The requirement is necessary to promote stronger regulatory relationships between the Division and transferee operators, ensuring that new operators are held to the same accountability standards and operating conditions as the original operator.

Proposed section 1724.6, **subdivision (g)**, would cause Project Approval Letters to expire upon the first day following 24 consecutive months of no injection occurring at the underground injection project. This amendment is intended to prevent the Division's review and approval of injection projects, including conditions imposed on projects, from growing stale due to a lack of operations over an extended period. The amendment will strengthen the Division's oversight of injection projects and ensure that field and other conditions are reviewed anew prior to the restarting of any injection project that has been dormant for more than two years.

1724.7. Project Data Requirements

Section 1724.7 specifies the information operators of injection projects must provide the Division to facilitate the Division's meaningful review of proposed and existing injection projects. The Division's 2015 UIC Program Assessment Report found the Division has not followed a "consistent standard of practice for collecting and maintaining information about [UIC] projects."[4] The proposed amendments to section 1724.7 would clarify and augment the list of data requirements with the goal of standardizing and uniformly increasing the information provided to the Division, thereby leading to more informed project evaluations and greater consistency in the Division's regulatory files for underground injection projects. While the Division currently requests much of the specified data as a matter of practice, the amendments to this section are necessary to promote transparency and uniform standards.

Proposed **subdivision (a)** would bring to the forefront the Division's core review criteria for UIC projects – namely, a demonstration that injection fluid will be confined to the approved injection zone, and that the project will not cause damage to life, health, property, or natural resources. While fluid confinement is addressed elsewhere in the Division's regulations, the Division finds it necessary for transparency and consistency purposes to highlight its importance as a primary evaluative criterion for the approvability of new and existing injection projects. This standard is consistent with, and implements, Public Resources Code section 3106.

Proposed **subdivisions (a)(1), (a)(2), and (a)(3)** would reorganize, clarify, and augment the elements of the existing requirements for an engineering study, geologic study, and injection plan. The reorganization of the data elements is intended to better associate data of related type and subject matter with the relevant overarching requirement (i.e., engineering study, geologic study, and injection plan). Other clarifying amendments and augmented data requirements are intended to improve the quality of project data and result in more informed project evaluations. The changes to the engineering study, geologic study, and injection plan requirements are:

- The statement of the primary purpose of the project would be moved from the engineering study to the injection plan (existing subdivision (a)(1) to proposed subdivision (a)(3)(A)), which the Division considers a more appropriate location for the data requirement.
- The requirement for reservoir characteristic data would be moved from the engineering study to the geologic study (existing subdivision (a)(2) to proposed subdivision (a)(2)(A)), which the Division considers a more appropriate location for the data requirement. Proposed subdivision (a)(2)(A) would also add language clarifying the scope of the geologic characterization in order to improve data quality and consistency.
- The requirement for reservoir fluid data would be moved from the engineering study to the geologic study (existing subdivision (a)(3) to proposed subdivision (a)(2)(B)), which the Division considers a more appropriate location for the data

[4] *Underground Injection Control Program Report on Permitting and Program Assessment: Reporting Period of Calendar Years 2011-2014* (Oct. 2015), at p. 15.

requirement. Proposed subdivision (a)(2)(B) would also add non-hydrocarbon components in associated gas to the parameters for reservoir fluid data. This additional information is relevant to the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources because certain non-hydrocarbon components such as hydrogen sulfide can be very dangerous when inhaled.

- The requirement for casing diagrams of wells within the area affected by the project (existing subdivision (a)(4)) would be renumbered (proposed subdivision (a)(1)(C)(ii)), and would be modified in several key respects. First, the amended regulation would require that casing diagrams contain at least a minimum amount of information specified in proposed section 1724.7.1. The purpose, benefits and necessity of this change are discussed below, in relation to proposed section 1724.7.1. Second, the amendment would give operators the option of submitting the required information as flat file data sets rather than graphical diagrams. The reason for including this option is due to the fact that the data itself is most important to the Division's oversight of injection projects, and the Division anticipates being able to generate casing diagrams using its own resources so long as the operator provides the data. Finally, the amended regulation would refine the scope of wells subject to the requirement for casing diagrams (or equivalent information), changing the existing language, "wells within the area affected by the project," to wells "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." This change clarifies the scope of wells that could potentially act as conduits allowing fluid to migrate outside of the approved injection zone and must therefore be evaluated, and is necessary for transparency and consistent application of requirements.

- The requirement for a planned well-drilling and plugging and abandonment program would be retained and renumbered as part of the engineering study with a non-substantive wording revision (renumbered from existing subdivision (a)(5) to proposed subdivision (a)(1)(D)).

- Proposed subdivision (a)(1)(B) would add to the engineering study a map that depicts all wells within and adjacent to the boundary of the area of review, and certain water supply wells and subsurface industrial activities not associated with oil and gas production that are within the area of review. This information in map form is not consistently provided to the Division under existing regulations. The map will improve the Division's evaluation of injection projects and help the Division to implement its statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources. Additionally, having information on other subsurface industrial activities in the area is needed to facilitate efficient and accurate data interpretation, because such activities have the potential to affect the results of tests such as noise and temperature surveys.

- Proposed subdivision (a)(1)(C)(i) would require that operators provide certain factual information about the wells depicted in the map required under proposed subdivision (a)(1)(B). This additional information about the wells is similarly useful to the Division in evaluating injection projects, but is required as part of a separate compendium because it is too much information to depict on a map.
- The requirement for a structural contour map would be retained as part of the geologic study and renumbered as proposed subdivision (a)(2)(C). New language would also be added to make more specific the kinds of information that should be included in a structural contour map – namely faults and lateral containment features that are important in the evaluation of zonal isolation. The new language is intended to clarify the scope of the requirement and to result in better quality, and more consistent data for injection projects.
- The requirement for an isopachous map of each injection zone or subzone in the project area would be retained and renumbered as proposed subdivision (a)(2)(D). The requirement would be reworded to “isopach” map because that terminology is more consistent with modern usage.
- The requirement for at least one geologic cross section would be retained as part of the geologic study and renumbered as proposed subdivision (a)(2)(E). The requirement would also be modified by specifying that the cross section be in the area of review and through at least three wells, including one injection well. This is an augmentation of the existing regulation, which only requires that the cross section be through at least one injection well. Cross sections are used to verify the geologic interpretation of the field, and including additional wells in the cross section will enable greater confidence in the geologic interpretation of the field and injection zone. The increase in the number of wells included in the cross section is intended to result in better quality and more reliable project data, and more informed project evaluations.
- The requirement for a representative electric log would be retained as part of the geologic study and renumbered as proposed subdivision (a)(2)(F). The requirement would also be modified by including USDWs (if any) among the features that must be identified in the log. Adding this feature to the log requirement is necessary to yield more useful project data and enable the Division to fulfill its statutory responsibility to protect USDWs from endangerment.
- The requirement for a map that shows injection facilities, existing subdivision (c)(1), would be deleted because it is now duplicative of the Division’s production facilities regulations. (*See* Cal. Code Regs., tit. 14, § 1722.9 [a map of production

facilities, which include injection facilities, is a required element of spill contingency plans].)

- The requirement for the maximum anticipated surface injection pressure as part of the injection plan (existing subdivision (c)(2)) would be deleted because this information is already the subject of other provisions in the underground injection control regulations. In particular, proposed subdivision (a)(4) would require the data and determinations from compliance with proposed section 1724.10.3, which explains how the maximum allowable surface injection pressure will be determined. Allowing operators to propose a maximum “anticipated” surface injection pressure as part of the injection plan is potentially confusing and inconsistent with the other proposed requirements described above. Deleting the requirement from the injection plan is necessary to avoid this confusion and duplication.

- The requirement for a monitoring system under existing subdivision (c)(3) would be retained and renumbered as proposed subdivision (a)(3)(F). The proposed subdivision would also add a requirement for operators to consult with the State Water Resources Control Board or the appropriate Regional Water Quality Control Board (collectively, “Water Board”) in the event the Division or the Water Board requires groundwater monitoring in relation to the project. The Water Board has its own mandate to protect groundwater resources from degradation, and it reviews underground injection projects pursuant to a memorandum of agreement with the Division. If the Water Board concludes that groundwater monitoring is necessary, the Division intends to defer to the Water Board’s judgment and expertise, and would expect the operator to consult with the Water Board regarding the specific parameters of a groundwater monitoring program. The Division would anticipate incorporating any groundwater monitoring programs into the Project Approval Letter. This requirement is necessary to promote transparency, to clarify Division expectations, and to more effectively implement the Division’s statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

- The requirement for daily rate of injection, by well, under existing subdivision (c)(2) would be retained and renumbered as proposed subdivision (a)(3)(C). The proposed subdivision would also add, however, a requirement for operators to provide a statement of the anticipated project duration and the anticipated cumulative net volume of fluid to be injected. This additional information, which is not currently obtained under existing regulations, would improve the Division’s oversight and evaluation of injection projects, including the assessment of the proper area of review and ensuring fluid confinement to the approved injection zone.

- The requirement, under existing subdivision (c)(4), to include within the injection plan a description of the method of injection, would be retained and renumbered as proposed subdivision (a)(3)(B).
- The requirement for a list of proposed cathodic protection measures (if any), existing subdivision (c)(5), would be retained and renumbered as proposed subdivision (a)(3)(G).
- The requirement for information about the treatment of water to be injected (existing subdivision (c)(6)) would be deleted. The Division does not believe this information is useful for purposes of evaluating most projects, and the relevant chemical constituency of injection fluid will be provided under proposed subdivision (a)(3)(E), discussed below. The Division does not have any requirements for pre-injection treatment of water, and information about water treatment does not typically have any bearing on the potential health, safety, or environmental risks of the project because the Division's review is focused instead on ensuring that the injection fluid is confined to the approved injection zone. Nevertheless, for any project that includes an injection well located within one mile (by wellhead) and 500 feet (by injection/screened interval) of a water supply well, the Division would continue to obtain information about water treatment under proposed subdivision (e)(1) of section 1724.10. While this information would serve as an additional layer of assurance for projects near water supply wells, the Division does not consider it useful or necessary for the majority of injection projects.
- The requirement for source and analysis information regarding the injection liquid would be retained and renumbered (renumbered from existing subdivision (c)(7) to proposed subdivision (a)(3)(E)). The subdivision would also include minor wording revisions to clarify meaning, and would reference section 1724.7.2 for additional specifications regarding fluid analysis.
- The requirement for the location and depth of water source wells used in conjunction with injection projects would be retained and renumbered (existing subdivision (c)(8) renumbered to proposed subdivision (a)(3)(D)). The proposed subdivision would also add a requirement for operators to identify all other wells that are part of the project, including injection wells, affected production wells, water source wells, observation or other wells, and any known planned wells. Currently, this information is not consistently provided to the Division but would be helpful to the Division's oversight and evaluation of injection projects.

Proposed **<u>subdivision (a)(4)</u>** would require operators to provide the data supporting the determination of the maximum allowable surface injection pressure (commonly referred to as "MASP") for each injection well in the underground injection project. An appropriate MASP helps ensure that injection pressures will not damage confining layers of the underground formation and be the cause of fluid leaving the approved injection zone. Ensuring that fluid remains in the approved injection zone is a key performance standard of the Division's regulatory program for underground injection operations. The migration of fluid of varying quality between different underground formations can be detrimental to both protected groundwater resources and hydrocarbon resources. Therefore, data that demonstrates an appropriate MASP is necessary to effectively evaluate an underground injection project.

Proposed **subdivision (a)(5)** would be the new numbering for existing section 1724.7, subdivision (d), which is the requirement for operators to provide copies of notice letters sent to offset operators. Other than new numbering, the text of this requirement would be unchanged.

Proposed **subdivision (a)(6)** would revise the existing provision (section 1724.7, subdivision (e)), which clarifies that the Division may, on a case-by-case basis, require an operator to provide additional data when the Division determines that the additional data is necessary for effective regulatory evaluation of any given injection project. The revisions do not change substantive requirements, but would more accurately describe the scope of additional data that may be required. Specifically, the new language would explain that the Division may require additional data for any injection project, not just "large, unusual, or hazardous" projects. The amendments are necessary to promote transparency and accurate expectations regarding potential data needs.

Proposed **subdivisions (b) and (c)** would provide specifications as to when and how the Division must be provided data. For example, proposed subdivision (b) would require operators to provide any new and relevant data when adding a new well to the injection project. These provisions are necessary to improve the quality and completeness of data the Division uses to evaluate injection projects, and to promote administrative efficiency in the Division's data gathering and management practices.

Proposed **subdivision (d)** would add a requirement for data to be submitted under a cover letter bearing the names and signatures of the individuals responsible for preparing the data submission. Any data that is subject to the requirements of the Geologist and Geophysicist Act (Bus. & Prof. Code, § 7800 et seq.) or the Professional Engineers Act (Bus. & Prof. Code, § 6700 et seq.) and must therefore be prepared by or at the direction of an appropriate licensed professional would need to be accompanied by a cover letter bearing the licensed professional's stamp and signature. The need for certain data to be prepared and certified by a licensed professional is an existing requirement of the Geologist and Geophysicist Act that is enforced by the Board for Professional Engineers, Land Surveyors, and Geologists. The Division often receives data without indication of the professional who prepared and certified the data, even though the data appears to require preparation by a licensed professional. Proposed subdivision (d) would remind operators of the need for a licensed professional to certify certain data. The proposed amendment is necessary to ensure that the data and analysis that the Division relies upon is prepared and submitted in compliance with California's licensing requirements for geologists and engineers.

Proposed **subdivision (e)** adds language intended to preserve, within specified parameters, the Division's existing discretion to make case-by-case determinations regarding the acceptance of alternative data. While the data requirements of section 1724.7 are intended to be appropriate for the vast majority of injection projects, the Division finds it necessary and appropriate to retain limited flexibility when evaluating the sufficiency of data submissions. Flexibility in the data requirements allows the Division to ensure it has whatever data is needed to evaluate a project, and ensures that the Division may always evaluate injection projects under the performance standard and that projects will not be categorically rejected based on prescriptive data requirements. Subdivision (e) only allows for alternative project data in instances where it would be infeasible or an unreasonable burden to provide the required data, and the Division is satisfied that the alternative data meets the performance standard and purposes of subdivision (a).

Section 1724.7.1. Casing Diagrams

Proposed section 1724.7.1 would specify the information that must be included in casing diagrams required under section 1724.7. Ensuring that injection fluid will be confined to the approved injection zone is a key performance standard by which the Division evaluates injection projects. Other wells within the area of review that penetrate the injection zone could potentially serve as conduits for fluid migration, and must therefore be evaluated for integrity and other conditions. Casing diagrams are needed to facilitate this review.

Although casing diagrams are an existing data requirement for injection projects, the Division's existing regulations do not specifically identify much of the information that the Division finds necessary to properly evaluate the wells within the area of review. As a result, the casing diagrams historically submitted in connection with many existing injection projects do not identify all potential issues with the wells. The Division therefore has ongoing concerns about wells within the area of review for many injection projects.[5]

Proposed section 1724.7.1 would address this problem by standardizing the minimum requirements for casing diagrams. The Division considers all of the information identified in subdivisions (a) and (b) as relevant and necessary to its evaluation of wells within the area of review of injection projects. Subdivisions (c) and (d) would provide additional standards clarifying the scope of information the Division deems relevant and necessary in a casing diagram. Finally, subdivision (e) would allow operators to submit a flat file data set containing all of the information identified in the section, in lieu of an actual casing diagram. This option, which may reduce compliance costs for some operators, is being

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[5] *See Underground Injection Control Program Report on Permitting and Program Assessment: Reporting Period of Calendar Years 2011-2014* (Oct. 2015), at pp. 12, 14, 16 [citing casing diagram deficiencies as a recurring data gap in the Division's project files for existing injection projects].

offered because the Division can use its own electronic resources to draw casing diagrams based on the data operators submit.

More complete casing diagrams will enable the Division to ensure that wells within the area of review cannot act as conduits for fluid migration. Listing this information in regulation is necessary because the current regulations have resulted in casing diagrams of inconsistent quality and completeness. Access to complete and accurate casing diagram information is necessary for effective implementation of the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

1724.7.2. Liquid Analysis

The Division's underground injection regulations (existing and as proposed in amended form) require two kinds of fluid analyses: an analysis of the downhole reservoir fluid (i.e., an analysis of the native fluid as it exists in the injection zone) required under section 1724.7(a)(2)(B), and an analysis of the injection liquid required under section 1724.10(d). Both fluid analyses are part of the project data requirements, while injection liquid analyses are also required whenever the source of the injection liquid is changed. While these analyses are existing requirements, the Division's current regulations do not specify procedures or the tested constituents. The lack of specificity in the current regulation creates the potential for confusion and inconsistent fluid analyses.

Proposed section 1724.7.2 would resolve these issues by specifying the constituents that must be assessed in injection liquid analyses. The constituents listed in proposed subdivision (a) are the most useful and relevant to inform the Division's understanding of the reservoir fluid and the injection fluid. The Division consulted with the State Water Resources Control Board to identify the list of constituents as an appropriate baseline for project evaluation purposes. Subdivision (b), however, would acknowledge for transparency purposes the Division's authority to require testing for additional constituents based on project-specific factors. Subdivision (c) would specify that injection liquid must be sampled after all additives are added, and after the liquid undergoes all treatment or separation processes. This requirement is necessary to ensure the injection liquid analyzed is representative of the liquid actually injected. Finally, subdivision (d) is necessary to promote data integrity and reliability by requiring that analyses be performed and submitted by a laboratory accredited by the State Water Resources Control Board. If an underground injection project involves injection of gas, then requisite chemical analysis would be determined by the Division on a project-specific basis.

Proposed section 1724.7.2 defining the requirement for liquid analysis is necessary to standardize the information available to the Division to evaluate injection project risks, and to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

1724.8. Data Required for Cyclic Steam Injection Project Approval [DELETED]

The proposed amendments would delete the current section 1724.8, which contains two minor "data requirements" for cyclic steam injection projects. The existing section would be removed because it is unnecessary and leads to confusion about the scope of requirements for cyclic steam injection. Additionally, the two requirements being removed are already covered elsewhere in the Division's proposed regulations (section 1724.6, subdivision (a) and section 1724.7, subdivision (d) (renumbered as proposed section 1724.7, subdivision (a)(5)). Cyclic steam injection would be included within the proposed definition of "underground injection project," and is subject to all sections of the Division's underground injection regulations.

1724.8. Evaluation of Wells Within the Area of Review [ADDED]

The Division is charged with the responsibility to ensure underground injection projects do not cause damage to life, health, property, and natural resources (including both USDWs and hydrocarbon resources). To carry out this mandate, the Division evaluates injection projects for their potential to cause fluid to migrate outside of the approved injection formation into other formations. Fluid migration between different geologic zones can be a problem when low quality or contaminated fluid enters higher quality groundwater (including USDWs), or when unwanted fluid enters hydrocarbon reservoirs. In order to protect USDWs and other zones from injection fluid, the Division evaluates whether other wells within the area of review for the injection project have the potential to act as vertical conduits for fluid migration. This potential may arise depending on the condition of the wells within the area of review, and can be of particular concern for idle or poorly abandoned wells that lack the internal fluid pressure that could otherwise help repel the entry of external fluid.

Proposed section 1724.8 would make explicit the performance standard that injection projects not cause or contribute to the migration of fluid outside of the approved injection zone. A well that is within the area of review for an injection well and that penetrates the injection zone has potential to act as a conduit for fluid to migrate outside of the intended injection zone, and proposed **subdivision (a)(1)** makes clear that any such well must be evaluated to ensure that it is not a conduit. Where well records do not clearly demonstrate that a well is not a potential conduit, additional testing or logging of the well may be necessary in order to provide the requisite assurances that such wells will not act as conduits for fluid migration.

Additionally, proposed **subdivision (a)(2)** would establish a substantive rule that plugged and abandoned wells within the area of review must be in a specified condition – namely, have cement across all perforations and extending at least 100 feet above certain points identified in the proposed regulation. Wells that are not abandoned in the specified condition will need to be addressed, either through physical work to meet the standard, or through ongoing monitoring to detect potential fluid migration. Proposed subdivisions (a)(1) and (a)(2) may require operators to cooperate with other operators as needed to address wells located within the area of review. However, regardless of who owns a well that is a potential conduit, the Division will not approve injection that has the potential to result in fluid migration outside of the approved zone, and operators carry the burden of taking whatever steps may be necessary to provide assurances of fluid confinement.

Finally, proposed **subdivision (a)(3)** would allow the Division to approve injection operations based on an alternative demonstration that fluid will be confined to the approved injection zone notwithstanding the presence of abandoned wells that fail to meet the specifications set forth in proposed subdivision (a)(2). This allowance for an alternative demonstration is necessary because there may be instances where operators can demonstrate fluid confinement despite the presence of abandoned wells that do not meet the specifications. For example, if a plugged and abandoned well has only 90 feet of cement above the specified locations, there may nevertheless be project or site-specific grounds for finding that the well will not act as a conduit. Operators, however, would carry the burden of making the demonstration, and the Division would also be required to make written findings explaining the basis for its concurrence.

Proposed section 1724.8 would promote transparency and consistency in the Division's evaluation of injection projects. It would standardize the minimum evaluative criteria, and would require that identified deficiencies be addressed with physical remediation, monitoring, or alternative findings for fluid confinement. In turn, the proposed section would result in increased Division oversight of injection projects, and better avoidance of potential damage to public health, natural resources, and the environment associated with fluid migration. The Division's current regulations do not clearly articulate these substantive review criteria. Committing these review criteria to regulation is necessary to promote consistent evaluation of injection projects, and to further implementation of the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

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

Section 1724.10 contains various additional requirements that apply to underground injection projects. The proposed amendments to this section would set a more uniform threshold of minimum safety, testing, and operational requirements for injection projects. Improving these requirements through regulation rather than relying on case-by-case application in Project Approval Letters responds to the Division's 2015 UIC Program Assessment Report, which found that some Project Approval Letters issued in the past are incomplete, inconsistent, and lacking in clarity as to what operations were approved and under what conditions the project is required to operate.[6] Augmenting the operating and testing regulations for all injection projects will promote greater consistency in the Division's regulation of injection projects, and improve transparency for the public and regulated community. These changes to operating and testing requirements for injection projects are necessary for effective implementation of the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

The proposed amendments to **subdivisions (a), (c), and (g)** are minor changes to improve clarity and consistency in the regulatory text. The changes are not substantive but are necessary to the overall structure and interpretation of the regulations.

The proposed amendment to **subdivision (b)** would reword the regulation for greater consistency with Public Resources Code section 3203. That statute specifies when operators must file notices of intention, but it is unclear whether the statute allows for the existing requirement that operators file notices of intention to convert an existing well to an injection well when "no work is required on the well." The proposed amendment would clarify that Division approval is required whenever an injection well is added to an existing project, but that such approval need not involve notices of intention where there is no triggering work on the well. In addition to improving consistency with Public Resources Code section 3203, the proposed amendment is also necessary to clarify the requirement and ensure that the addition of any well to an existing project is subject to Division review and approval.

The proposed amendment to **subdivision (d)** would require that operators file a chemical analysis of the injection liquid (in accordance with proposed section 1724.7.2) whenever the source of injection liquid is changed, and as requested by the Division. This is required under existing regulation, however, in practice, what constitutes a change in the source of the injection liquid has at times been a point of ambiguity.

The proposed amendment to **subdivision (d)** includes revisions to help resolve that ambiguity. The proposed amendment calls for a "representative" chemical analysis to be clear that the ultimate performance standard is that the chemical analysis that the operator provides to the Division must reflect liquid that is currently being injected. Further, the proposed amendment would make clear that a new analysis is required whenever the relative contributions of sources change such that the chemical analysis may no longer be representative of the injection liquid. The Division believes it is important for both regulatory and public transparency purposes to have injection fluid analyses that accurately reflect the chemical composition of current injection fluid. Such data will improve the Division's knowledge of injection projects and facilitate better risk management decisions with respect to injection projects.

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[6] *See Underground Injection Control Program Report on Permitting and Program Assessment: Reporting Period of Calendar Years 2011-2014* (Oct. 2015), at p.16.

Proposed **<u>subdivision (e)</u>** would add an annual reporting requirement regarding water treatment and fluid additives for any project that includes an injection well located within 500 feet (by injection/screened interval) of a water supply well. While the Division's regulation of underground injection projects is focused on ensuring injection fluid remains confined to the appropriate, approved injection zone regardless of its constituents, the proposed subdivision would serve to collect information that could be used to help verify whether or not injection fluid is contaminating water supply wells. Obtaining information about chemical additives in injection fluid would help the Division and other regulators respond in the event that contamination is reported in water supply wells (including agricultural supply wells) located near injection wells. The information would help determine whether the injection fluid is a potential source of contamination. The proposed amendment is necessary to obtain this information for the injection wells located near water supply wells.

The Division's existing regulations require that injection wells be equipped for installation of a pressure gauge or pressure recording device. Proposed amendments to **<u>subdivision (f)</u>** would modernize the requirement by calling for operators to continuously record injection pressures at all times that a well is injecting. Continuous injection pressure data would be useful to the Division when investigating incidents such as surface expressions or reports of groundwater contamination. The data would also enable the Division to verify injection reporting. The current requirement that a pressure gauge or recording device "be available at all times" does not yield useful data. Instead, the current regulation only allows the Division to obtain a pressure reading at one specific point in time, and the Division must take additional steps such as making a site visit or request that the operator take a gauge reading. The amendment is necessary to require continuous pressure recording on a well-by-well basis. Well-specific recording is necessary to yield data useful for investigations and reporting verification. Operators would be required to maintain the data so long as the well is classified as an active injection well. This requirement is also necessary to maximize the utility of the data. Although the proposed amendment would reference a supervisory control and data acquisition system (commonly referred to as "SCADA") as an available technology, the regulations would not specify the use of particular equipment, and there are several device options for continuously recording injection pressure.

Proposed amendments to **<u>subdivision (h)</u>** would affect the requirement for injection wells to be equipped with tubing and packer. The current requirement exempts "steam, air and pipeline quality gas injection wells" from the tubing and packer requirement. The amended regulations would preserve the exemption for steam injection (cyclic steam and steamflood injection), as further discussed below, but would delete the exemption for air and pipeline quality gas injection wells because separate regulations address the requirements for such wells. (*See* Cal. Code Regs., tit. 14, sections 1726–1726.10.)

The amendment would also add language making clear that injection wells equipped with tubing and packer may not inject through the casing-tubing annulus without specific approval from the Division. When injection fluid is injected through the tubing only, the tubing serves as an additional barrier to the well casing between the injection fluid and the underground formation penetrated by the well. When injection is allowed to occur through the casing-tubing annulus, the ability of the tubing to serve its purpose as a secondary barrier is eliminated. This clarifying language is therefore necessary to ensure that such injection practices do not defeat the intended purpose of tubing and packer completions.

Finally, the proposed subdivision would amend language describing the applicability and scope of exemptions from tubing and packer. The existing exemption for steam wells (cyclic steam and steamflood) would be retained, but the applicability of the other exemptions would be changed to reflect situations where there are no threats to USDWs rather than "freshwater." The Division is responsible for protecting USDWs, which generally includes aquifers containing 10,000 mg/l TDS or less. The term "freshwater" has historically been interpreted to include only groundwater containing 3,000 mg/l TDS or less. Accordingly, the current exemptions from tubing and packer, tied to protection of freshwater, must be revised to more accurately implement the Division's protection of USDWs. Language would also be added to explain that operators have the burden of producing evidence to demonstrate the applicability of the exemptions, and that the Division must confirm the applicability in a writing. This change is necessary to promote greater transparency and oversight in the Division's regulation of injection wells.

The proposed amendments would remove **existing subdivision (h)**. The sentence in this subdivision regarding the cessation of injection would be moved to proposed section 1724.13, which addresses operating restrictions and incident response. The remainder of that subdivision would be duplicative of proposed section 1724.7, which would provide a more complete statement of the performance standard and requirements for maintaining project data in support of an underground injection project.

The proposed amendments to **subdivision (i)** would replace the current requirement for step rate tests with a provision requiring surface injection pressure not to exceed the maximum allowable surface pressure as determine under 1724.10.3. The requirement for step rate tests would be relocated to that same proposed section 1724.10.3. The proposed section explains how the data from step rate tests is to be used, along with other specified factors, in calculating the maximum allowable surface injection pressure.

The proposed amendments to **subdivision (j)** would rearrange and restate existing language regarding the applicability of mechanical integrity testing, requirements for providing advance notice of testing to the Division, and requirements for providing test results to the Division, with some additional specifications. The proposed subdivision would include a requirement that injection wells be constructed and maintained to allow for compliance with mechanical integrity testing, which is necessary to ensure that required testing is feasible. Consistent with the operating restriction and incident response requirements of proposed section 1724.13, subdivision (k) would prohibit injection in a well that is out of compliance with the mechanical integrity testing requirements. The purpose of this requirement is to ensure that injection only occurs in wells with demonstrated mechanical integrity.

The proposed amendments to **subdivision (j)** would also remove language addressing the types and frequency of required mechanical integrity testing for injection wells because proposed sections 1724.10.1 and 1724.10.2 would cover these topics in greater detail. The Division's existing regulations require a "two-part demonstration" of mechanical integrity. (*See* existing section 1724.10, subdivision (j).) The first part, addressed in proposed section 1724.10.1, consists of a pressure test of the casing-tubing annulus, while the second part, addressed in proposed section 1724.10.2, consists of a test to demonstrate the absence of fluid migration behind the casing, tubing, or packer.

Proposed **subdivision (k)** would add a provision referencing Project Approval Letters as the source of monitoring requirements. The Division considers project-specific Project Approval Letters to be more appropriate than regulations of general applicability to convey monitoring requirements, which are likely to depend on site-specific concerns. The amendment would promote transparency regarding the Division's regulatory procedures.

Proposed **subdivision (l)** would require operators of cyclic steam injection wells to maintain records of the number, duration, and fluid volume of all injection cycles performed on each cyclic steam injection well. Such information can vary significantly among cyclic steam wells, and may be useful to the Division for a variety of purposes, including enforcement or incident response investigations, as well as determining well or project-specific regulatory requirements. A cyclic steam well that frequently cycles between injection and production, or one that injects large fluid volumes, may require a different level of regulatory oversight than a cyclic steam well that infrequently injects a small volume of fluid. The requirement would also enable the Division to audit representations in project approval applications and other reporting regarding injection volumes. The Division's current regulations do not require operators to maintain this useful information. The regulation would support Division oversight and enforcement, improve information available to the Division in incident response, and help the Division prioritize attention among the thousands of cyclic steam wells in California.

Finally, paragraph (5) of **existing subdivision (k) (renumbered as subdivision (m))** would be deleted because it relates to gas storage projects, which are addressed in separate regulations. (*See* Cal. Code Regs., tit. 14, sections 1726–1726.10.)

1724.10.1. Mechanical Integrity Testing Part One – Casing Integrity

Proposed section 1724.10.1 would provide specification for the required periodic demonstration of the casing integrity of each injection well. Proposed **subdivision (a)** would require periodic casing pressure tests performed at the maximum allowable surface pressure (or 200 pounds per square inch, whichever is greater). One initial point of departure from the Division’s existing regulations is that the amended requirement would replace the requirement to pressure test the “casing-tubing annulus” with a requirement to do a “pressure test of the casing.” The current language assumes the presence of tubing and packer even though the regulations allow certain injection wells, like cyclic steam, to be completed without tubing and packer. This has resulted in confusion and inconsistent application of the testing requirement for wells without tubing and packer. Shifting the focus of the requirement to testing of the casing will make clear that all injection wells are subject to the pressure testing requirements, regardless of whether the well is equipped with tubing and packer. This is necessary because mechanical integrity is a concern with any well that will be used for Class II injection operations, especially if the well does not have the secondary protection of tubing-and-packer construction. Proposed section 1724.10.1 would not change the existing requirement to pressure test an injection well prior to commencing injection and every five years after that, but the proposed regulation would allow operators five years to test existing wells that were not previously required to be pressure tested.

The proposed subdivision would specify the parameters to conduct the pressure test, and to determine whether a well passes the test. Testing at the maximum allowable surface pressure is necessary to confirm the well can hold the maximum pressure at which it is allowed to operate. The regulation would also specify what constitutes a passing test: the pressure must be held for one hour with no more than a 10 percent decline from the initial test pressure in the first 30 minutes, and no more than a 2 percent decline from the pressure after the first 30 minutes in the second 30 minutes. The proposed subdivision would require approval and consultation with the Division before conducting a pressure test with gas or using additives other than brine, corrosion inhibitors, or biocides, because such modification could affect the efficacy of the testing parameters. The proposed subdivision specifies that the pressure gauge employed must be sufficiently accurate (within 1 percent) to effectively indicate whether the well passed or failed the pressure test.

The proposed subdivision calls for a stable column of fluid that is free of excess gasses in the wellbore before commencing pressure testing, but the regulation does not specify benchmarks to determine when this has been achieved. Achieving stability before commencing pressure increases the likelihood of a passing test, and the Division will defer to the operator’s knowledge of its own operating conditions to determine how long a well should sit before beginning testing.

These parameters were developed by Division engineers in consultation with experts from the Sandia, Lawrence Livermore, and Lawrence Berkeley National Laboratories in an effort to develop consistent and effective pressure testing parameters to be employed whenever pressure testing is required for oil and gas wells. They are based on industry standards and practices, and the Division’s extensive experience and expertise in supervising the pressure testing of wells.

For wells equipped with tubing and packer, operators would have the option of performing a pressure test at lower pressures followed by ongoing annular pressure monitoring. Proposed **subdivision (b)** details the process and parameters for this alternative integrity demonstration. The alternative demonstration is intended to enable operators to avoid pressurizing the well to the full maximum allowable injection pressure, provided that the well passes periodic pressure tests at lower pressure and is thereafter subject to annular pressure monitoring. Even though this alternative does not result in pressure testing at the maximum allowable pressure, it can be as good or better at detecting potential problems with the casing. Whereas a full pressure test verifies the integrity of a well at a given point in time, the alternative monitoring program would indicate potential problems on an ongoing basis. Partly for this reason, there is less of a need to require pressure testing at the maximum allowable injection pressure for wells subject to an ongoing monitoring program.

The purpose of the proposed pressure testing requirements is to ensure that injection only occurs in wells with demonstrated mechanical integrity, and these requirements are necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

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

Proposed section 1724.10.2 would augment the existing testing requirement to demonstrate the absence of fluid migration behind the casing, tubing, or packer. The existing requirement for this "part two" mechanical integrity testing is found in section 1724.10, subdivision (j)(2). That regulation could provide better guidance and direction regarding the procedures for operators to use to make the required demonstration. Proposed **subdivision (a)** would remedy this by specifying that operators can satisfy the requirement by performing the procedures specified in proposed subdivisions (d) through (f) – namely, a radioactive tracer survey, noise log, or temperature survey. Additionally, the proposed regulation would allow flexibility for the Division to accept an alternative method. Because operators would have several options to satisfy the requirement (including case-by-case methods not set forth in the regulation), operators would need to obtain written approval from the Division prior to performing the procedure. Specifying acceptable procedures in the proposed regulation will make the Division's expectations more transparent, yield higher quality test data, and result in more consistent application of testing standards.

Proposed **subdivision (b)** identifies when "part two" testing is required. Consistent with existing regulation, testing is required within three months after commencing injection in the well, and then periodically after that at a frequency based on the type of injection occurring in the well. The existing regulation requires testing every year for water-disposal wells, every two years for waterflood wells, and every five years for steamflood wells. Consistent with existing regulation, the proposed subdivision sets testing frequencies based on the type of injection well, but with some changes. The frequency for disposal wells would still be every year, for waterflood wells it would still be every two years, and for steamflood wells equipped with tubing and packer it would still be every five years. But for steam flood wells without tubing and packer, the required testing frequency would be at least once every two years. The existing regulation does not specify a frequency for injection wells that are not used for water-disposal, waterflood, or steamflood, and the proposed subdivision would close that gap by establishing a default testing frequency of at least once every two years for all injection wells not specifically addressed in the subdivision.

The existing regulation is silent with regard to the testing frequency for cyclic steam injection wells, which have come to be the most common type of injection well in the state. This lack of specificity as to frequency has led to instances of such injection wells going untested. The Division finds no science- or risk-based reason to excuse cyclic steam wells from "part two" mechanical integrity testing. Indeed, cyclic steam wells, which periodically inject hot, highly pressurized steam, are repeatedly subject to considerable variations in temperature and pressure. These factors subject the well to stress, which makes the wells vulnerable to integrity failure. At the same time, cyclic steam wells typically inject smaller volumes of fluid that is of better quality than fluid injected at other kinds of injection wells (the fluid needs to be relatively clean for the steam generation process). Accordingly, the proposed regulation would require most cyclic steam wells not equipped with tubing and packer to be tested at least once every two years. Cyclic steam wells equipped with tubing and packer would only need to be tested at least once every three years because the use of tubing and packer provides an additional layer of protection against fluid migration from a well with compromised casing integrity.

The testing frequency would also be revised to differentiate between steamflood injection wells equipped with tubing and packer, and such wells not equipped with tubing and packer. Current regulations do not require tubing and packer for steamflood wells, and the current "part two" test frequency for steamflood wells is five years. The Division considers five years to be too infrequent for steamflood wells unless they are equipped with tubing and packer, which would provide a secondary assurance of well integrity. Those wells equipped with tubing and packer would still be subject to the five-year schedule, but most steamflood wells not equipped with tubing and packer would be subject to testing at least once every two years. Steam wells lacking the additional layer of protection provided by tubing and packer should be subject to more frequent integrity testing.

As with existing regulation, proposed **subdivision (b)** provides for additional "part two" testing in response to anomalous occurrences and as specified by the Division. However, the phrase in the existing regulation, "anomalous rate or pressure change," would be replaced with a clearer threshold of "an unplanned variance in injection pressure of more than fifteen percent within a 24-hour period."

The testing methods and frequencies set forth in the proposed regulation are intended to be the default requirements that would apply for the majority of injection projects, but the Division finds it necessary to allow regulatory flexibility for deviation from the default on a case-by-case basis. This flexibility is necessary because California's geology, oilfield practices, and natural resource landscapes, are notoriously diverse, wells differ significantly in age and condition, and operators should not be prevented from identifying more efficient means of effectively demonstrating well integrity. In feedback on the Division's pre-rulemaking draft of the proposed regulations, operators repeatedly urged against a "one-size-fits-all" regulatory approach. Proposed **subdivision (c)** would allow the Division to approve testing methods and frequencies that differ from the defaults set forth in the proposed section, provided that the variance, and its basis, is effective and well documented. This provision will avoid an unduly rigid testing requirement and enable the Division to tailor requirements to specific circumstances where appropriate.

Proposed **subdivisions (d), (e), and (f)** would specify the default parameters for an acceptable radioactive tracer survey, temperature survey, and noise log, respectively. These parameters are based on industry standards and practices, and the Division's experience and expertise in supervising such testing procedures. The purpose of these new sections is to provide transparency in the Division's expectations for acceptable "part two" mechanical integrity testing procedures, make the testing regime more reliable and predictive in nature, and therefore improve the likelihood of identifying potential well integrity issues before leaks occur. **Subdivisions (a) and (c)** allow for operators to employ alternative testing methods or protocols, provided the Division is satisfied that the proposed approach will effectively demonstrate whether there is fluid migration behind the casing, tubing, or packer.

Proposed **subdivision (g)** would require operators to take immediate action to investigate any anomalies encountered during "part two" mechanical integrity testing. It would also require operators to take immediate action to prevent damage to public health, safety, and the environment, and to notify the Division immediately, if there is any reason to suspect fluid migration. This requirement would be consistent with proposed section 1724.13, discussed below, which describes required responses to various incidents. The Division considers it appropriate and necessary to include this requirement in the section about mechanical integrity testing as well, to ensure operators are fully aware of their responsibilities in the event of anomalous test results.

Mechanical integrity testing, as required under proposed sections 1724.10.1 and 1724.10.2, is necessary to ensure fluid is confined to the approved injection zone and does not escape through leaks in the well casing. While no single type of mechanical integrity test provides complete information about the condition of a well, the combination of required tests will provide the Division and the operator multiple sets of data about the well, which will improve detection of current and potential well integrity concerns. Effective mechanical integrity testing requirements under proposed sections 1724.10.1 and 1724.10.2 are necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to supervise injection wells and to prevent damage to life, health, property, and natural resources.

1724.10.3. Maximum Allowable Surface Injection Pressure

The Division's existing regulations, at section 1724.10(i), require a maximum allowable surface injection pressure (commonly referred to as MASP) that is below the fracture pressure, as determined by a step rate test. A step rate test is not necessary if the Division determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection. Proposed section 1724.10.3 would amend these requirements to specify the formula to calculate MASP, to ensure that MASP is in every case supported by sound data and analysis, to allow necessary flexibility for the Division to approve MASP above fracture pressure in specific circumstances, and to establish consistent protocols to conduct step rate tests.

Proposed **subdivision (a)** provides that MASP is calculated by multiplying the true vertical depth of the shallowest portion of the well open to the injection zone by the difference between the injection gradient and the injection fluid gradient (MASP = (IG - IFG) * TVD), which is the basic formula for calculating MASP. In order to build in a reasonable safety factor, the proposed subdivision would require that the injection gradient be the product of the fracture gradient multiplied by 0.95. However, the operator would be able to propose a different multiplier on a well-specific basis to account for factors such as friction loss.

Subdivision (a) as proposed would allow injection pressures to exceed fracture gradients in cases where the operator can demonstrate that a higher pressure is needed for effective resource production, and that injection fluid will remain confined to the approved zone and not otherwise threaten life, health, property, and natural resources. As long as the operator can establish that the injection fluid will not leave the approved injection zone, the Division believes it may be appropriate in some cases to allow injection (within the approved formation) above the fracture gradient. This flexibility is necessary because there are circumstances where injection above fracture pressure is appropriate, in particular with underground injection projects involving injection into diatomite formations, where the formation fracture gradient is so low that it is impossible to inject below the fracture gradient.

Consistent with existing regulation, proposed section 1724.10.3 would allow for MASP determinations based on a conservative estimate of the fracture gradient in the area that the well is drilled, but proposed **subdivision (b)** would require that such an estimate be adequately supported by representative step rate test data or other testing or geologic data. If an injection is not within an area covered by estimated baseline fracture gradient approved under proposed subdivision (b), or if the operator wishes to establish a higher well-specific fracture gradient, then proposed **subdivision (c)** would require well-specific step rate test data to support the MASP determination for that well. These requirements, which would apply to new and existing injection wells, are necessary to ensure that MASP is based on sound science and data in every case.

Proposed **subdivision (d)** would establish required standards and protocols to conduct step rate tests under this proposed section. Consistent with guidance from US EPA Region 8, the key performance standards would be:

- Before commencing the test, the well must be shut in until the bottom-hole pressures approximate shut-in formation pressures.
- Each step of the step rate test must result in a stabilized pressure value.
- Each step of the step rate test must be conducted for the same amount of time.

Proposed **subdivision (d)** also includes specifications to notice the Division before conducting the test, recording the test, and submitting test results to the Division. These testing standards and protocols are necessary to ensure that MASP determinations are supported by clear, consistent, and reliable step rate test data.

The proposed subdivision would result in more complete project data and more appropriate MASPs, which in turn, would aid the Division's implementation of its statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources. Proposed **subdivision (a)(4)** is intended and is necessary to better define the need for step rate tests, limit the circumstances in which the requirement can be satisfied by alternative data, and ultimately result in more effective prevention of potential harms associated with projects operating under inappropriate pressure limits.

Adequate step rate test data is necessary because it is used to inform the injection pressure limits that are necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources. Inadequate tests result in unreliable data, resulting in poorly informed or inappropriate project pressure limits.

The amendments to the MASP determination requirements in proposed section 1724.10.3 are necessary to ensure that injection is confined to the intended injection zone and they are therefore necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources. Additionally, these amendments will increase transparency and standardization in the Division's determination of MASP for each injection well.

1724.11. Surface Expression Prevention and Response

Proposed section 1724.11, **subdivision (a)**, would codify in regulation the Division's policy that underground injection operations not result in surface expressions. The term "surface expression" would be defined in the regulations (proposed section 1720.1, subdivision (k)) as 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, and that appears to be caused by injection operations. Surface expressions can result when injection fluid migrates outside of the approved injection zone – an occurrence the Division's UIC regulatory program is intended to protect against – and often indicate injection at pressures, temperatures, or volumes above what the receiving formation can safely handle. Surface expressions are also highly hazardous to humans and wildlife. In 2011, an oilfield worker died when he accidentally fell into a surface expression. Codification of this policy in regulation will promote transparency, and is necessary for effective implementation of the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

Proposed **subdivision (b)** sets forth preventative monitoring requirements that would apply to all underground injection projects that, in the Division's judgment, have the potential to cause a surface expression, and to all steam injection projects in diatomaceous formations unless there is a satisfactory, project-specific demonstration that surface expressions are not a concern. The Division believes it is appropriate to adopt a rebuttable presumption that injection into diatomaceous formations creates a risk of surface expressions due to the particular geologic qualities of diatomaceous earth. The preventative requirements consist of the use of a ground monitoring system, the use of a real-time pressure/flow monitoring system, 24-hours a day on-site staff, daily visual inspections, and continuous monitoring of steam injection rates and pressures to assess for variances. The Division considers these elements necessary to effectively monitor for warning signs of a surface expression.

If a threat of surface expression is detected, the proposed regulation would require the operator to cease injecting into nearby injection wells in order to mitigate the threat. Injection would be prohibited until the Division provides written approval to resume. The requirements of proposed subdivision (b) are necessary to facilitate early detection of surface expressions or anomalies that could cause surface expressions. Without a standardized set of monitoring requirements, the Division must impose requirements in individual project approval letters – an approach the Division considers inferior to regulation in this instance. The proposed regulation will help prevent surface expressions from occurring, and will promote consistent application of standards.

Proposed subdivisions (c) through (j) are requirements that apply if a surface expression occurs. Proposed **subdivision (c)** would require operators to notify the Division if a surface expression occurs, changes, or reactivates within the operator's lease. Operators would also need to provide the ground monitoring data from at least two weeks prior. This notice and information will ensure the Division is provided the information it needs to work with operators to develop appropriate responses to surface expressions.

Proposed **subdivision (d)** would require automatic cessation of injection at wells with injection intervals located within a 300-foot radius of a surface expression. If the surface expression continues to flow for more than five days, the cessation radius would double to 600 feet. After ten days of ongoing flow from a surface expression, the Division would determine the expanded cessation radius. Proposed **subdivision (e)** would acknowledge and preserve the Division's discretionary authority to direct injection operations to cease at a well, regardless of its distance from the surface expression, if the Division finds reason to believe the well is causing or contributing to the surface expression.

The distance-based shut-in provisions are necessary to standardize the minimum response actions in the event of a surface expression. The Division believes that in many cases, the closer the injection well is to a surface expression, the more likely that well is causing or contributing to its existence. The proposed requirement is also intended and is necessary to increase the consequences for causing surface expressions. Automatic cessation requirements will incentivize safer, more prudent injection activities, proactively discouraging at the outset oilfield practices that can lead to surface expressions.

Proposed **subdivision (f)** would require operators to demarcate in the field those wells that have ceased injecting due to the presence of a nearby surface expression. Proposed **subdivision (g)** would require Division approval to restart injection at such wells. These requirements are necessary to facilitate effective Division oversight and enforcement of the proposed requirements.

Proposed **subdivision (h)** would require operators to report a surface expression as an oil spill, if there is a reportable quantity of oil, so that the California Emergency Management Agency may appropriately oversee a cleanup effort. This regulation is intended to ensure that operators are aware of and comply with spill reporting requirements.

Proposed **subdivision (i)** would require operators to restrict access to areas containing surface expressions, and to mark those areas with appropriate signs. The signs would need to be consistent with requirements of the California Division of Occupational Safety and Health (Cal/OSHA), which apply to occupational hazards like surface expressions. The requirement would promote public safety in the field, and is necessary to ensure consistent safety practices as required by applicable Cal/OSHA regulations.

Proposed **subdivision (j)** would require operators to measure and report on the volumes of oil removed from surface expressions. These volumes can be significant, and can be produced and sold as a commodity. Current regulations do not require operators to report such volumes. The requirement is necessary to enable the Division to track and record oil recovered from surface expressions, which will provide a valuable data point for the Division's regulation of the California oil and gas industry.

The proposed section will help mitigate the risk of damage from surface expressions by requiring a standardized response program to be implemented consistently, without the need for further action or order from the Division. This change is necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

1724.12. Surface Expression Containment

Proposed section 1724.12 sets forth minimum requirements that would apply if an operator elects to install a surface expression containment measure. Proposed **subdivision (a)(1)** would require notice to allow the Division to observe and document the installation of the containment measure.

Proposed **subdivision (a)(2)** would require that containment measures be designed and supervised by a California-licensed engineer, and proposed **subdivision (a)(3)** would require the licensed engineer to provide a written report to the Division following completion of the containment measure. These requirements would ensure that the containment measures would be implemented by a professional who meets minimum qualifications, and is an appropriate application of an existing legal requirement of the Business and Professions Code.

Proposed **subdivision (a)(4)** would require operators to continuously monitor and record the surface expression and the containment measure, and notify the Division of any changes. Such monitoring and notification are necessary to provide the Division up-to-date information of the surface expression flow in order to assess how well the containment measures are working.

Finally, proposed **subdivision (a)(5)** would require operators to map, mark, and restrict access to containment measures in the field. This requirement would promote the safety of industry workers, Division employees, and the public.

As a whole, the proposed section will improve the Division's effective oversight of surface containment measures by ensuring that operators' use of surface expression containment measures is properly accounted for, and that the containment measures meet minimum safety-related standards. The proposed section is necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

1724.13. Universal Operating Restrictions and Incident Response

Proposed section 1724.13, **subdivision (a)**, would specify a list of circumstances that require operators to notify the Division and cease injection until, as required by **subdivision (b)**, the Division authorizes resumption. Some of the circumstances, such as a failed mechanical integrity test and indication of fluid migration outside of the approved injection zone, relate directly to the Division's statutory mandate to protect life, health, property, and natural resources. Other circumstances, such as failure to perform a mechanical integrity test within the required time frame and failure to submit injection and production reports, are intended to impose stronger consequences for noncompliance with testing and reporting requirements. With respect to all circumstances listed in the proposed section, the Division finds that operators should be required to cease injection on their own initiative rather than wait for the Division to follow up with such directions.

These proposed regulations will strengthen the Division's oversight of injection wells and help reduce threats to life, health, property, and natural resources by halting injection into wells that are not compliant with legal requirements. Reporting and testing requirements are central to the Division's UIC program. Under existing regulations, operators who violate those requirements sometimes continue operations until the Division issues a remedial order. The proposed section would delineate clear, immediate, and consequential obligations for operators to cease injection if the well is not in compliance with the specified requirements. Operators who continue to inject in violation of the proposed section would be separately liable for violating this proposed section, in addition to the underlying violation (if applicable) that triggered the obligation to cease injection. The Division anticipates that the proposed section will improve operator compliance with reporting and testing requirements. The proposed section is necessary to implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

Additionally, the purpose of proposed **subdivision (c)**, is to notify operators that each day of injections in violation of proposed subdivision (a) will be considered a separate violation for purposes of calculating civil penalties. (The Division has authority under Public Resources Code section 3236.5 to impose civil penalties for violations of applicable statutes and regulations.) Proposed **subdivision (c)** is necessary to promote transparency regarding how the Division plans to assess violations. Treating each day of injection as a separate violation is also necessary to provide adequate disincentive for noncompliance.

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

Proposed section 1724.14 would require operators to monitor seismic activity near disposal injection wells, and to report certain seismic events to the Division. The purpose of this proposed section is to provide the Division, operators, and the public more complete data regarding seismic activity near disposal injection wells. This data would allow the Division to better assess and track potential relationships between disposal injection and seismic activity, which has the potential to damage surface structures or create subsurface conduits allowing injection fluid to migrate outside of the approved injection zone.

Proposed section 1724.14, **subdivision (a)**, would require the operator to monitor, on a daily basis, the California Integrated Seismic Network (CISN) for earthquakes 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. The proposed section accomplishes the need to monitor seismic activity near disposal injection wells at low cost to the industry. Operators can monitor in real time relevant seismic activity through CISN's free website.

The requirement would apply to disposal wells only because disposal wells generally inject greater volumes at greater depths than other types of injection wells, and therefore are more likely to be associated with seismic activity than any other form of injection well subject to Division regulation. The primary cause of induced seismicity related to Class II injection would be increased pore pressure due to disposal of large volumes of water. During enhanced oil recovery such as waterflood or steam injection, pore pressure is not increased because the injected volumes are smaller, and associated production results in a net decrease in pore pressure. Additionally, the reporting trigger would be limited to downhole injection intervals within a one-mile spherical radius of the hypocenter, which is the underground center-point of the seismic activity. The distance between the injection interval and the hypocenter is a more appropriate trigger than the distance between the injection internal or wellhead and the epicenter (the point on the earth's surface directly above the seismic activity), because the latter would result in reporting events that are much less likely to be connected with injection, particularly where the hypocenter is miles below wells injecting into geologically separate formations at only hundreds of feet below the surface. Limiting the requirement to disposal wells within a certain distance from the hypocenter is necessary to appropriately tailor the regulatory burdens to the applicable activities and issues of most concern.

The threshold magnitude of 2.7 was selected by assessing the capabilities of the CISN to locate magnitude 2-3 seismicity with sufficient accuracy to satisfy the proposed requirement. The accuracy of the CISN's information on location, size, and depth of a seismic event is directly related to the number and types of seismic instruments in a given area. In many areas of California, network density is not sufficient to allow for a threshold lower than magnitude 2.7.

Proposed section 1724.14, **<u>subdivision (b)</u>**, specifies that if an earthquake of magnitude 2.7 or greater is identified under subdivision (a), then the operator shall notify the Division within 24 hours and report the earthquake's time, location, epicenter, and hypocenter. This will also trigger a consultation between the Division and the California Geological Survey to assess patterns and other indications of causal relationships between the seismic activity and injection operations. Proposed **<u>subdivision (b)</u>** promotes public transparency regarding the Division's response to certain seismic events, and is necessary to create a consistent framework for the response and evaluation with a sister agency possessing expertise in seismic analysis.

1748. Underground Injection Control

The existing section 1748 identifies regulatory sections with specific application to offshore disposal and injection projects. Proposed section 1748 would update the regulatory text to reflect the definition of "underground injection project" provided in proposed section 1720.1, subdivision (m). Proposed section 1748 would also update the regulatory text to indicate that the regulatory provisions set forth in title 14, chapter 4, subchapter 1, article 4 of the California Code of Regulations apply to underground injection projects located offshore. The purpose of this change is to clarify that the core requirements for safe operation of underground injection control projects located onshore also apply to underground injection projects located offshore. The Division believes that establishing these core requirements for underground injection projects are equally suited for projects located offshore. This is because while offshore and onshore underground injection projects do present some different situations and challenges, from a regulatory standpoint, much of their core functionality is the same. Establishing a harmonized set of core requirements for underground injection projects in a single collection of regulatory provisions will promote clarity. Additionally, providing a cross-reference to the applicable regulatory sections has the benefit of reducing unnecessary duplication. This revision is necessary to effectively implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

1748.2. Injection Projects [DELETED]

Existing section 1748.2 requires an operator seeking Division approval for an underground injection project located offshore to provide various types of data to the Division, to assist the Division with pre-approval evaluation of the project. The proposed regulations would delete this section, because it would be supplanted by the new and more comprehensive requirements presented in the proposed regulatory provisions set forth in title 14, chapter 4, subchapter 1, article 4 of the California Code of Regulations, including most specifically the project data requirements presented in proposed section 1724.7. Under proposed section 1748, these provisions of article 4 would apply to offshore underground injection projects. This deletion will promote clarity by establishing a harmonized set of core requirements for underground injection projects in a single collection of regulatory provisions, thereby avoiding unnecessary duplication. This revision is necessary to effectively implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

1748.3. Injection Requirements [DELETED]

Existing section 1748.3 requires an operator of an underground injection project located offshore to complete various forms when seeking Division approval to perform work on a well. Existing section 1748.3 also requires an operator of an underground injection project located offshore to provide the Division with a monthly report of injection on a form, to conduct chemical analysis of injection fluids every two years or whenever the source of the fluid changes, to maintain accurate pressure gauges or charts at the wellhead, to maintain sufficient data to demonstrate safe operation of the project, to cease injection upon written notice from the Division, and to comply with additional requirements imposed by the Division as necessary to accommodate special circumstances. The proposed regulations would delete this section, because it would be either duplicative of or supplanted by the new and more comprehensive requirements presented in the proposed regulatory provisions set forth in title 14, chapter 4, subchapter 1, article 4 of the California Code of Regulations. Under proposed section 1748, these provisions of Article 4 would apply to offshore underground injection projects. This deletion will promote clarity by establishing a harmonized set of core requirements for underground injection projects in a single collection of regulatory provisions, thereby avoiding unnecessary duplication. This revision is necessary to effectively implement the Division's statutory mandate under Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources.

STANDARDIZED REGULATORY IMPACT ASSESSMENT

The Division has determined that this rulemaking action is a major regulation and has completed a Standardized Regulatory Impact Assessment (SRIA) for this rulemaking. The SRIA has been provided to the California Department of Finance (DOF) for review and comment. The SRIA, DOF's comments on the SRIA, and the Division's response to DOF's comments are attached as "Attachment A."

ALTERNATIVES CONSIDERED

In the course of developing the proposed regulations, the Department considered and rejected various alternative approaches. No alternative considered by the Department would be more effective in carrying out the purposes of the proposed regulations, or would be as effective but less burdensome to affected private persons and small businesses than the proposed regulations. The alternatives considered include the following:

- The Division considered but rejected requiring "part two" mechanical integrity testing (*i.e.,* testing to demonstrate the absence of fluid behind casing, tubing, or packer) on an annual basis for all wells. This would have been a change from the risk-based frequencies of the current regulations, and would have increased the frequency of testing for all wells other than disposal injection wells. The proposed regulations would retain the risk-based approach, while clarifying that cyclic steam injection wells are subject to "part two" testing. Consistent with the risk-based approach, the proposed regulations would require more frequent testing for cyclic steam and steamflood injection wells that are not equipped with tubing and packer. The Division rejected an annual testing frequency for all wells because not all wells have the same risk of failure, and not all wells pose the same risks to health and natural resources in the event of failure. On this issue, the Division agrees with the numerous comments from the regulated industry urging against a "one-size-fits-all" approach. Additionally, mechanical integrity testing can be a source of wear on a well, and more frequent testing may result in additional risk compared to the benefits derived by more frequent testing. Increasing the testing frequency would therefore not be as effective in carrying out the purposes of the proposed regulations.

- The Division considered but rejected eliminating the provision in current regulations exempting cyclic steam and steamflood injection wells from being equipped with tubing and packer. Although tubing and packer provide an additional barrier between injection fluid and the geologic formations penetrated by the well, tubing and packer may pose operational challenges for steam wells that outweigh the safety benefits. Increased risks are incurred because both the frequency and complexity of workovers would increase. Complexity is increased because without a packer, a well can be easily circulated in accordance with industry well control best practice to ensure that workover fluids are effectively controlling the well both immediately after unseating the pump and also before pulling tubing. There are workarounds available when a packer is present, but they add complexity to the workover. In workover operations, additional complexity increases risk as well as cost. Also, the frequency of workovers on cyclic steam wells would increase substantially. Typically, a cyclic steam well would require a workover about once a year due to the bottomhole pump wearing out. As indicated by industry representatives, requiring tubing and packer would require a workover before and after every cyclic steam cycle, which would likely be at least a four-fold increase in frequency. Additionally, the proposed regulations would account for the additional risk factor from wells not equipped with tubing and packer by requiring such wells to undergo more frequent “part two” mechanical integrity testing in comparison to wells of the same type equipped with tubing and packer. The proposed regulations would allow operators to decide based on operational circumstances whether to equip tubing and packer or perform more frequent mechanical integrity testing. Accordingly, the proposed regulations are as effective in accomplishing the purposes of the regulation, but would be less burdensome to the affected industry than an automatic tubing and packer requirement for cyclic steam and steamflood injection wells.

- The Division considered but rejected a longer list of analytes for the fluid analyses described in proposed section 1724.7.2. The Division received considerable feedback that the list of analytes published in the Discussion Draft regulations was overly burdensome and would have resulted in excessive sampling costs. The Division consulted with the State Water Resources Control Board and determined that the list of analytes in the proposed regulations is more appropriate given the nature of the fluids sampled and the relevance of the information. Additionally, the Division’s regulatory program for underground injection wells focuses primarily on ensuring that injection fluid will remain confined to the approved injection zone. While chemical constituency may be useful information for certain purposes, chemical composition (beyond the analytes listed in the proposed regulation) is less important and determinative than the assurance of fluid confinement. Nevertheless, the proposed regulation would make explicit the Division’s authority to require testing for additional constituents on a project-specific basis.

- The Division considered but rejected a suggestion to allow the installation of pressure gauges at the manifold of several wells. The Division determined that the mere installation of pressure gauges, including at the manifold level, would be inferior to the requirement in the proposed regulation—namely, continuous recording of well-specific injection pressure. As discussed above, the Division believes there is a regulatory benefit to continuous well injection pressure data. The Division also believes there are several technological options to satisfy the requirement, and that the benefits outweigh the compliance costs. Mere installation of a gauge is inferior because a gauge does not continuously record and maintain the beneficial data. Accordingly, the alternative would not be as effective in carrying out the purposes of the regulation.

- The Division considered but rejected omitting friction loss as a potential factor in the calculation of maximum allowable surface injection pressure. Failure to account for friction loss, however, could result in maximum allowable surface injection pressures that are too low (or unnecessarily low) in certain wells with high friction loss such as directionally drilled wells. The proposed regulations would make the consideration of friction loss subject to Division approval. The ability to consider friction loss, or other well-specific factors, in maximum allowable surface injection pressure calculations would be as effective in accomplishing the purposes of the regulation, while maintaining appropriate flexibility to avoid unduly restricting the regulated industry.

UNNECESSARY DUPLICATION OR CONFLICTS WITH FEDERAL REGULATIONS

These proposed regulations do not unnecessarily duplicate or conflict with federal regulations contained in the Code of Federal Regulations addressing the same issues. In California, the Division has primacy to implement the mandates of the federal Safe Drinking Water Act with respect to underground injection wells associated with oil and gas production. In essence, the Division's UIC regulations displace any comparable federal regulations that address underground injection associated with oil and gas production. (*See* 40 C.F.R. § 147.250 [the program for such wells in California "is the program administered by the [Division]"].) In any event, the proposed regulations are generally consistent with the regulations US EPA has adopted for injection wells in states that lack federal primacy.

DOCUMENTS RELIED UPON

The Department relied upon the following documents in proposing this rulemaking action:

- Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act, dated April 20, 1981
- Memorandum of Agreement between the Division and US EPA re: Class II UIC Program, dated September 29, 1982 (*two versions, with Department of Conservation note*)
- Memorandum of Agreement Between the State Water Resources Control Board and the Division, dated May 19, 1988
- Underground Injection Control Program Report on Permitting and Program Assessment (Reporting Period of Calendar Years 2011-2014)
- Underground Injection Control Program Report on Permitting and Program Assessment (Reporting Period of October 1, 2015 – March 31, 2016)
- Division's Renewal Plan for Oil and Gas Regulation (October 2015)
- 2017 Update to Division's Renewal Plan for Oil and Gas Regulation (April 2017)
- Correspondence between the Department of Conservation and US EPA regarding the Division's implementation of the UIC Program (dated December 22, 2014

through November 9, 2017) (available on the Division's website at http://www.conservation.ca.gov/dog/general_information/Pages/UndergroundinjectionControl(UIC).aspx)

- California Class II Underground Injection Control Program Review, Final Report (US EPA, June 2011, Horsley Witten Group)
- Division Response to the US EPA June 2011 Review of California's UIC Program (November 2012)
- Division Internal Memorandum from Elena M. Miller to District Deputies re: "Underground Injection Control Program Expectations" (May 20, 2010)
- Evaluation and Surveillance of Water Injection Projects (Division Publication No. M13)
- State Water Resources Control Board Resolution No. 88-63 (as revised by Resolution No. 2006-0008), "Adoption of Policy Entitled 'Sources of Drinking Water'" (February 1, 2006)
- Step Rate Test Procedure, Guidance Document, US EPA, Region 8 (January 12, 1999)