UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

FINAL 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 3; as well as subchapter 1.1, article 3. In particular, the Department would add sections 1720.1, 1724.5, 1724.7.1, 1724.7.2, 1724.8, 1724.10.1, 1724.10.2, 1724.10.3, 1724.10.4, 1724.11, 1724.12, and 1724.13; amend sections 1724.6, 1724.7, 1724.10, and 1748; and delete existing sections 1724.8, 1748.2, and 1748.3.[1] As part of these changes, within California Code of Regulations, title 14, division 2, chapter 4, subchapter 1, the Department proposes to reorganize the existing article 4 by renumbering it as article 5, and to create a new article 4 that will contain newly added sections as well as various sections previously located within article 3.

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 hydrocarbons from underground reservoirs, the California oil and gas industry also uses 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 sixty 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 seventy-five percent of the roughly 600,000 barrels of oil produced daily in California (thirty-five

[1] Unless otherwise specified, references in this document to a "section" are references to sections of California Code of Regulations, title 14.

percent of California's daily petroleum use) results from the use of EOR injection methods.

Injection wells also function as a disposal method for the large volumes of water that are drawn up with the hydrocarbons. Due to the maturity of California's oil fields, every barrel of oil extracted from underground is comingled with over fifteen 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 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 geological and engineering data, well construction requirements, and periodic testing to demonstrate the mechanical integrity of each injection well. Many of the UIC regulatory requirements intended to ensure that the injection fluid will be confined to the approved injection zone and not migrate into a zone where it could degrade valuable groundwater or hydrocarbon resources.

The Division's staff comprises 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 geologists and engineers, 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") for regulating 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 its 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 for regulating 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 or less milligrams per liter total dissolved solids).

Need to Update the Division's UIC Regulations

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 died tragically 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. These 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. This rulemaking to update the Division's UIC regulations with improved standards that better align with the commitments expressed in the Primacy Agreement with US EPA and with modern industry practices is central to the program overhaul.

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

The Division's existing regulations required 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 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 has increased significantly beginning in the 1990s, ambiguities in the Division's existing regulations have enabled excessive variability in the Division's regulation of cyclic-steam injection wells, with some wells avoiding certain UIC requirements. Other concerns the 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 Engagement in Support of This Rulemaking

In developing the proposed regulations, the Division conducted extensive public outreach to solicit input on the substance and economic impacts of the contemplated changes to existing 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 information about direct costs. The proposed regulations evolved significantly during the course of this extensive pre-rulemaking public process.

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 and sign up to receive future communications about the rulemaking. 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 regarding specific regulatory text presented in two iterations of pre-rulemaking "discussion draft" versions of the proposed regulations. On January 21, 2016, the Division made a first pre-rulemaking "discussion draft" available for public comment, soliciting public input through March 4, 2016. On April 26, 2017, after considering input received and making revisions to the text, the Division released a second "discussion draft," soliciting public input through June

26, 2017. During that time, the Division also conducted another public workshop in Bakersfield to discuss the latest version of the regulatory text and its overall development status.

Between the summer of 2017 and the summer of 2018, the Division carefully reviewed input received from the public, the State Water Resources Control Board, Regional Water Quality Control Boards, and the US EPA.

During the summer of 2018, the Division initiated the formal rulemaking process for the proposed regulations. A public comment period on the originally proposed regulations was held from July 27, 2018, through September 13, 2018, pursuant to the Notice of Proposed Action mailed to interested parties and duly published in the California Regulatory Notice Register on July 27, 2018 (Register 2018, No. 30-Z (July 27, 2018)). During that public comment period, two public hearings were conducted: one in Bakersfield on September 12, and one in Los Angeles on September 13. After reviewing the comments received, engaging in further direct consultation with interested stakeholders, and revising the text of the proposed regulations, the Division held a final public comment period, from October 29, 2018, through November 14, 2018, to receive input on the first revised text of the proposed regulations.

PURPOSE, RATIONALE, AND BENEFITS (GENERALLY)

In general, this rulemaking action will improve the regulatory standards applicable to underground injection operations associated with oil and gas development in California via changes that raise the bar for operational safety, modernize criteria for compliance evaluation, and standardize a number of existing regulatory practices. The proposed action will also increase transparency regarding the Division's regulatory standards and expectations for underground injection projects. These changes are necessary for the Division to carry out its statutory mandate under Public Resources Code section 3106: to prevent, as far as possible, damage to life, health, property, and natural resources, while also permitting the operators of wells to utilize all known and suitable methods for increasing the ultimate recovery of underground hydrocarbons.

SPECIFIC PURPOSE, RATIONALE, AND BENEFITS

Below is an explanation of each newly added, amended, or repealed regulatory section associated with this rulemaking action. These explanations address the specific purpose for each change, the rationale for why each change is reasonably necessary to achieve its purpose and to effectuate the objectives of the statutory authority it implements, and the anticipated benefits of each change.

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 section 1720.1 is to clarify the meaning of ambiguous terms, promote transparency, and support consistent application of the regulations. 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.

The term **"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 base on project-specific data and factors. Regarding determination of an appropriate area of review, the definition clarifies that an appropriate area of review will be at least as broad as the area influenced by the underground injection project.

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.

The term **"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.

The term **"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.

The term **"fluid"** is defined as any material or substance which flows or moves, whether semisolid, liquid, gas, or steam. The definition is consistent with the scientific and dictionary definitions of the term, but is necessary because "fluid" is frequently colloquially understood to mean only liquid.

The term **“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 longstanding 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 regulations. The specificity provided by this definition will improve the transparency of the Division’s regulatory practices.

The term **“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.

The term **“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.

The term **“low-energy seep”** is defined as a particular type of surface expression. A surface expression may be classified as a low-energy seep for regulatory purposes if an operator demonstrates to the Division that the fluid coming to the surface: is not injected fluid; is not hot; is not being released to the surface with high energy; and is being contained and monitored so as to ensure it will not damage life, health, property, or natural resources. A surface expression meeting the definition of a low-energy seep presents different, generally lesser, regulatory concerns than do other surface expressions. Defining this term is necessary because the term may be subject to more than one interpretation. The purpose of this term is to give meaning to distinctions drawn elsewhere in the regulations between the different requirements applicable to surface expressions that are low-energy seeps and those that are not.

The term **“low-use cyclic steam injection well”** is defined as a cyclic steam well that is not part of underground injection project that has been known to cause surface expressions, and that in the past five years has not had more than 24 days of injection or 12,000 barrels of injection in a calendar year. This definition provides bright-line criteria for identifying cyclic steam wells that present a lower level of regulatory concern than other cyclic steam injection wells. As discussed below, operators are not required to conduct “part-two” mechanical integrity testing under Section 1724.10.2 as frequently for cyclic steam wells that meet these criteria as for other cyclic steam wells.

The Division determined the thresholds in this definition by examining the typical usage pattern of cyclic steam wells over the past five years, focusing on wells not located in diatomite fields. Wells in diatomite fields were excluded from the analysis because those fields are where surface expressions tend to be a concern. The Division found, in a five-year average, that one standard deviation above the average for the frequency of injection is about 24 days per year. The Division also found that the majority of those wells that inject for 24 days or less, per year, do not inject more than 12,000 barrels per year. Taken together, fewer than half of all cyclic steam wells in the state inject for less than 24 days and 12,000 barrels in any given year.

The term **"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 regulations.

The term **"project approval letter"** is defined as the written record by which the Division documents its approval for operation of an underground injection project, along with any applicable conditions limiting that approval. 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.

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

The term **"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 regulations include requirements for surface expressions and surface expression containment.

The term **"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 regulations include requirements for surface expression containment measures.

The term **“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.

The term **“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 has consulted with the US EPA to ensure that this definition harmonizes with the definition in federal regulation. The definition is necessary to give a specific meaning to the term, which is used elsewhere in the regulations.

The term **“water source well”** is defined as a well, situated near oil or gas resources, that provides water for use in production stimulation or repressuring operations. Wells that supply water for use in these types oilfield operations present a different set of regulatory concerns for the Division compared to wells that supply water for other purposes. This definition is necessary to give specific meaning to the term and to articulate the distinction between those categories of water wells elsewhere in the regulations.

The term **“water supply well”** is defined as a well that provides water for domestic, municipal, industrial, or irrigation purposes, and that is not a water source well. Defining the term is necessary to give specific meaning to its usage elsewhere in the regulations.

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

Article 4. Underground Injection Control

Within title 14, division 2, chapter 4, subchapter 1, the proposed rulemaking will create a new article 4, titled “Underground Injection Control.” This organizational change will facilitate easy and accurate reference to the proposed regulations as the “underground injection control regulations,” or “UIC regulations,” a shorthand description already common among those who work within this area of regulation. Because of this change, the existing article 4, titled “Requirements for Underground Gas Storage Projects,” will be renumbered to become article 5.

1724.5. Purpose, Scope, and Applicability

The purpose of section 1724.5 is to summarize and clarify the purpose, scope, and applicability of the regulations appearing under article 4, “Underground Injection Control.” Section 1724.5 will provide the benefit of clarifying that all underground injection projects will be regulated according the requirements set forth under the newly organized article 4. Section 1724.5 also clarifies that underground injection projects will not be regulated under article 5, “Requirements for Underground Gas Storage Projects.” Clearly stating the purpose, scope, and applicability of the UIC regulations is necessary to implement effectively the Division’s 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.

1724.6. Approval of Underground Injection 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] Section 1724.6 is necessary and intended to address these problems by ascribing greater meaning to Project Approval Letters as the document that specifically identifies, on a project-specific basis, the terms and conditions under which the Division approves operation of an underground injection project.

Section 1724.6, **subdivision (a)**, will promulgate in regulation the Division’s longstanding practice of conveying approval for underground injection projects through Project Approval Letters. The amendment will clarify and memorialize the existing expectation that proponents of underground injection projects must submit the data specified in section 1724.7 in addition to any other data the Division deems necessary. The amended text also codifies the Division’s practice of consulting with the State Water Resources Control Board and Regional Water Quality Control Boards when reviewing proposals seeking Division approval of new underground injection projects. These amendments will provide the benefit of greater standardization and transparency regarding the Division’s approval mechanism for underground injection projects.

Subdivision (b) will explain that Project Approval Letters will be used to identify basic facts about the underground injection project, and also to convey the Division’s conditions of approval. These conditions, which operate as limitations to the scope of Division

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

approvals, are typically included in individual Project Approval Letters as part of the Division's current practice. Subdivision (b) will clarify that one way in which the Division may limit the scope of an approval is to approve an underground injection project on the condition that the approval will only last for a limited period of time. Subdivision (b) also will establish a standard for every Project Approval Letter to include, as part of the identification of pertinent facts and conditions, an identification of the approved injection zone. Additionally, subdivision (b) will confirm with the transparency of regulatory text the understanding that an approved injection zone will not include an area that is an underground source of drinking water. The amendment will commit to codified regulation existing Division regulatory practice as well as recent improvements to the Division's regulatory practice, with the benefit of ensuring that Project Approval Letters are informative and enforceable documents delineating the scope and limitations of underground injection projects.

Subdivision (c) will provide that subsequent Division approval is required for any modification of an underground injection project. Under existing regulatory practices, this limitation is typically conveyed in Project Approval Letters. The subdivision is necessary to ensure that the limitation applies to every underground injection project, regardless of whether it is stated in the Project Approval Letter.

Subdivision (d) will 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 will also make clear that approval of injection projects is subject to the Division's ongoing discretion throughout the life of the project.

Subdivision (e) will 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.

Subdivision (f) will require the new operator of a transferred underground 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 operator is held to the same accountability standards and operating conditions as the original operator.

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 will 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.

Subdivision (a) will 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.

Subdivisions (a)(1), (a)(2), and (a)(3) 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 as follows:

- The statement of the primary purpose of the project will be moved from the engineering study to the injection plan (existing subdivision (a)(1) to subdivision (a)(3)(A)), which the Division considers a more appropriate location for the data requirement.

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

- The requirement for reservoir characteristic data will be moved from the engineering study to the geologic study (existing subdivision (a)(2) to subdivision (a)(2)(A)), which the Division considers a more appropriate location for the data requirement. Subdivision (a)(2)(A) will also add language clarifying the scope of the geologic characterization in order to improve data quality and consistency.
- The requirement for reservoir fluid data will be moved from the engineering study to the geologic study (existing subdivision (a)(3) to subdivision (a)(2)(B)), which the Division considers a more appropriate location for the data requirement. Subdivision (a)(2)(B) will 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)) will be renumbered to subdivision (a)(1)(C)(iii) and will be modified in several key respects. First, the amended regulation requires that casing diagrams contain at least a minimum amount of information specified in section 1724.7.1. The purpose, benefits and necessity of this change are discussed below, in relation to section 1724.7.1. Second, the amendment gives operators the option of submitting the required information as flat file data sets rather than graphical diagrams. This option is included because 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 refines 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 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 will be retained and renumbered as part of the engineering study with a non-substantive wording revision (renumbered from existing subdivision (a)(5) to subdivision (a)(1)(D)).
- Subdivision (a)(1)(B) adds 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, as well as traces of relevant geologic cross section data from the geologic study required by subdivision (a)(2)(E). This information provided 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, as such activities have the potential to affect the results of tests such as noise and temperature surveys.

- Subdivision (a)(1)(C)(i) will require that operators provide certain factual information about the wells depicted in the map required under 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 will be retained as part of the geologic study and renumbered as subdivision (a)(2)(C). New language makes 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, more consistent data for injection projects.
- The requirement for an isopachous map of each injection zone or subzone in the project area will be retained and renumbered as subdivision (a)(2)(D). The requirement would be reworded to "isopach" map as that terminology is more consistent with modern usage.
- As part of the geologic study, subdivision (a)(2)(E) will expand the existing requirement for at least one geologic cross section to a minimum of two geologic cross sections. Subdivision (a)(2)(E) also specifies several additional required criteria for these geologic cross sections: the cross sections must be in the area of review and pass through at least three wells, including one injection well; the cross sections must extend from the base of the deepest production or injection zone to surface; the cross sections must indicate the locations of the approved injection zone, base of freshwater, and base of the USDW; as nearly as possible one of the cross sections must be along strike and the other perpendicular to strike. This is an augmentation of the existing regulation, which only requires a single cross section, and 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 would enable greater confidence in the

geologic interpretation of the field and injection zone. The increase in the number of wells to be included in the cross sections, the requirement to align the cross sections along and perpendicular to strike when possible, to run the cross sections from the deepest production or injection zone to the surface, and to indicate the injection zone and various groundwater zones are all intended to produce better quality, more comprehensive project data. These improvements in the supporting project data will help the Division make better-informed project evaluations.

- The requirement for a representative electric log will be retained as part of the geologic study and renumbered as subdivision (a)(2)(F). The requirement is also modified by including USDWs (if any) among the features that must be identified in the log, and clarifying that log must run to the deepest zone used in the well, whether for production or injection, separate from any information presented on the cross sections required by subdivision (a)(2)(E). Subdivision (a)(2)(F) also adds a requirement for the electric log to identify the API number of the logged well, for ease of recordkeeping. Adding these features to the representative electric log requirement is necessary to yield more useful project data and enable the Division to fulfill its statutory responsibility to protect USDWs and other natural resources from damage.
- The requirement for a map showing injection facilities, existing subdivision (c)(1), will be renumbered as subdivision (a)(3)(B). Subdivision (a)(3)(B) also adds text clarifying that the map of injection facilities must show piping and instrumentation diagrams for the injection facilities related to the underground injection project. This clarification aligns the regulatory text with common practice and reflects what the Division believes to be prevailing understanding in the regulated community regarding the contents of a facilities map. This revision 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 the maximum anticipated surface injection pressure as part of the injection plan (existing subdivision (c)(2)) will be deleted because this information is already the subject of other provisions in the underground injection control regulations. In particular, subdivision (a)(4) will require the data and determinations from compliance with 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) will be retained and renumbered as subdivision (a)(3)(E). Subdivision (a)(3)(E) also adds

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 underground injection 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 expects to incorporate any groundwater monitoring program 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) will be retained and renumbered as subdivision (a)(3)(C). Subdivision (a)(3)(C) will 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, will 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 for a description of the method of injection, is retained and renumbered as subdivision (a)(3)(F). Subdivision (a)(3)(F) also add text clarifying that injection string configuration and bottom hole assembly are among the information expected to be included in an injection plan as part of the description of the method of injection. This clarification aligns the regulatory text with common practice and reflects what the Division believes to be prevailing understanding in the regulated community regarding what constitutes a detailed description of well-specific injection methodology. This revision 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 a list of cathodic protection measures (if any) (existing subdivision (c)(5)) will renumbered as subdivision (a)(3)(G) and modified to contemplate the use of corrosion prevention measures other than cathodic protection. This change clarifies that the purpose of this subdivision is to ensure that the project data includes a list of the corrosion prevention measures the operator actually uses rather than to prescribe cathodic protection as the corrosion

prevention measure an operator must use. This change is necessary to avoid the potential for misunderstanding of the regulatory intent.

- The requirement for information about the treatment of water to be injected (existing subdivision (c)(6)) will 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 subdivision (a)(3)(H), 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 subdivision (e) 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 will be retained and renumbered (renumbered from existing subdivision (c)(7) to subdivision (a)(3)(H)). The subdivision will also include minor wording revisions to clarify meaning, and would reference section 1724.7.2 for additional specifications regarding liquid analysis.

- The requirement for the location and depth of water source wells used in conjunction with injection projects will be retained and renumbered (existing subdivision (c)(8) renumbered to subdivision (a)(3)(D)). The subdivision would also add a requirement for operators to identify all other wells that are part of the underground injection project, including injection wells, affected production wells, water source wells, observation or other wells, and any known planned wells. This information currently is not consistently provided to the Division but would be helpful to the Division's oversight and evaluation of underground injection projects.

Subdivision (a)(4) will 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 demonstrating an appropriate MASP is necessary to effectively evaluate an underground injection project

<u>Subdivision (a)(5)</u> will 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.

<u>Subdivision (a)(6)</u> will 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 intended and necessary to promote transparency and accurate expectations regarding potential data needs.

<u>Subdivisions (b) and (c)</u> provide specifications as to when and how the Division must be provided data. For example, subdivision (b) requires an operator to provide any new and relevant data when adding a new well to an underground injection project, and establishes as a standard for project data that each injection well added to an underground injection project be documented on a summary list of approved injection wells associated with the project. These provisions are intended and 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.

<u>Subdivision (d)</u> 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. Subdivision (d) would remind operators of the need for a licensed professional to certify certain data. The proposed amendment is intended and necessary to ensure that the data and analysis that the Division relies upon is prepared and submitted and submitted in compliance with California's licensing requirements for geologists and engineers.

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).

1724.7.1. Casing Diagrams

Section 1724.7.1 specifies 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]

Section 1724.7.1 will 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)** provide additional standards clarifying the scope of information the Division deems relevant and necessary in a casing diagram. Finally, **subdivision (e)** allows operators discretion to submit the information required by section 1724.7(a)(1)(C)(iii) either as a graphical casing diagram or a flat-file file data set containing all of the required information. The flat-file data set option, which may reduce compliance costs for some operators, is being offered because

[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].

the Division can use its own electronic resources to draw casing diagrams based on the data operators submit, and perhaps also to tailor the contents of the drawn casing diagram to the specific informational needs at hand.

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 control regulations (existing and as proposed in amended form) require two kinds of liquid analyses: an analysis of the downhole reservoir liquid (i.e., an analysis of the native liquid as it exists in the injection zone) required under section 1724.7(a)(2)(B), and an analysis of the injection liquid required under sections 1724.7(a)(3)(H) and 1724.10(d). Both liquid 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.

Section 1724.7.2 would resolve these issues by specifying the constituents that must be assessed in liquid analyses required by the underground injection control regulations. The constituents listed in **subdivision (a)** are the most useful and relevant to inform the Division's understanding of the reservoir liquid and the injection liquid. The Division consulted with the State Water Resources Control Board to identify the list of constituents as an appropriate baseline for underground injection project evaluation purposes. **Subdivision (b)**, however, acknowledges for transparency purposes the Division's authority to require testing for additional constituents based on project-specific factors.

Subdivision (c) outlines basic sample collection procedures for reservoir liquid to ensure that the liquid analyzed is representative of the reservoir liquid in its native condition. Because a truly native condition (i.e., prior to receiving injection) sample of reservoir liquid may not be obtainable from reservoirs where approved injection has been occurring for many years, subdivision (c) provides operators the option to collect a sample from a geologically analogous reservoir that has not received injection fluid. A native condition sample of reservoir liquid, or one that closely approximates it, helps the Division and the Water Board evaluate what effects an underground injection project will have on the reservoir. It also may be compared against future reservoir liquid samples to monitor the actual effects of injection, and to ensure compliance with approved injection zone boundaries and other applicable requirements.

Subdivision (d) specifies that injection liquid must be sampled after all additives are added, and after the liquid undergoes all treatment or separation processes. This requirement is intended and necessary to ensure the injection liquid analyzed is representative of the liquid actually injected.

Finally, **subdivision (e)** 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.

Together, section 1724.7.2 defines the liquid analysis protocols for the underground injection control regulations. It is intended and necessary to standardize the information available to the Division in evaluating underground 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 existing 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 (a)(5) (the latter of which is merely a renumbering of existing section 1724.7, subdivision (d)). 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 responsibility for ensuring that 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.

When determining the extent of the approved injection zone and conducting the area or review evaluation, the Division's primary focus is protection of USDW. But the location of USDWs is not the only factor in determining the extent of the approved injection zone. The approved injection zone may reflect a conservative buffer around a USDW zone, there may be a need to protect groundwater that does not meet the definition of a USDW, and hydrocarbon reservoirs must be protected from infiltrating water or other detrimental substances.

Section 1724.8 makes explicit the performance standard that injection projects not cause or contribute to the migration of fluid outside the approved injection zone. A well that is within the area of review for an injection well and that penetrates injection has potential to act as conduit for fluid to migrate outside of the intended injection zone, and **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, logging, monitoring, or remediation 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, **subdivision (a)(2)** establishes a substantive rule that plugged and abandoned wells within the area of review must be in a specified condition – namely, have cement consistent with the current plugging and abandonment requirements in existing regulation section 1723.1. 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. 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 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, **subdivision (a)(3)** allows 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 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 with the demonstration.

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 section 1724.8 will 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 will improve transparency. 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 amendments to **subdivisions (a), (c), and (f)** 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 amendments to **subdivision (b)** 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

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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.

“no work is required on the well.” The amendments 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. Consistent with existing regulations, subdivision (b) reiterates that the operator must notify the Division and conduct required testing whenever the tubing or packer is reset, moved, or changed in an injection well. In addition to improving consistency with Public Resources Code, section 3203, these amendments are 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 amendments to **subdivision (d)** require that operators file a chemical analysis of the injection liquid (in accordance with 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 amendments to subdivision (d) include revisions to help resolve that ambiguity. The amendments specify 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 amendments 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 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.

Subdivision (e) adds 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 purpose of subdivision (e) is to collect information that could be used to help determine whether 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.

Subdivision (e) requires additive reporting for injection wells with open perforations within 500 feet of a water supply well. But the default 500-foot distance may not be appropriate in all circumstances, and the Division may request the chemical additive information on a project-specific or well-specific basis at a distance greater than 500 feet if geological conditions or the relative location of any water supply well warrants the additional data collection.

The Division's existing regulations require that injection wells be equipped for installation of a pressure gauge or pressure recording device. These requirements, previously found in existing subdivision (f), are deleted and replaced with section 1724.10.4. Section 1724.10.4, discussed below, requires operators to continuously record injection pressures at all times that a well is injecting.

Amendments to **subdivision (g)** affect the requirement for injection wells to be equipped with tubing and packer. The existing requirement exempts "steam, air and pipeline quality gas injection wells" from the tubing and packer requirement. The amended regulations preserve the exemption for steam injection (cyclic steam and steamflood injection), as further discussed below, but 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 also adds 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 purpose of the tubing to serve 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.

Technical requirements for packers in subdivision (g) are amended to allow greater flexibility. The requirement that packer must be set immediately above the injection has been amended to allow the packer to be set anywhere below 100 feet above the approved injection zone. But if the packer is set within the zone of injection, then it must not be set below open perforations. If the packer is placed in accordance with these parameters, then it will serve the purpose of isolating the injection zone and it is not necessary to prescribe placement immediately above the injection zone in all cases. The reference to protection of high-pressure zones is removed from subdivision (g)(3) because that consideration is not germane to whether it is appropriate to operate an injection without tubing and packer. In addition, amendments to subdivision (g) allow operators employ an alternative to a packer, if the operator demonstrates that the alternative will achieve the purpose of isolating the production tubing from the casing.

Finally, language is amended in subdivision (g) describing the applicability and scope of exemptions from tubing and packer. The existing exemption for steam (cyclic steam and steamflood) is retained, but the applicability of the other exemptions is now limited to circumstances where there are no threats to USDWs, rather than any circumstances where there are no threats to "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 is also 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, which is necessary for transparency and oversight in the Division’s regulation of injection wells.

For existing injection wells previously exempted from the tubing-and-packer requirements, operators will need to demonstrate that the wells meet the criteria for exemption under the amended regulation. And some of the previously exempted injection wells will not meet the new criteria and may need to be equipped with tubing and packer. Recognizing that this change will take time to implement, subdivision (g)(3) allows operators until April 1, 2021, to come into compliance with the new rule.

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

Subdivision (h) replaces the existing requirements of existing subdivision (i) for determining maximum allowable surface injection pressure for an injection well. The requirements for determining maximum allowable surface injection pressure, including protocols for step rate tests are relocated to section 1724.10.3, discussed below. Section 1724.10.3 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. Subdivision (h) cross references section 1724.10.3 to be clear that compliance with that section is critical operational requirement.

The amendments to **subdivision (i)** 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 amended subdivision includes 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) prohibits injection in a well that is out of compliance with the mechanical testing requirements. The purpose of this requirement is to ensure that injection only occurs in wells with demonstrated mechanical integrity. Requiring operators who do not comply with the mechanical testing requirements to halt injection into the noncompliant well is an appropriate consequence with the simultaneous benefits of motivating timely compliance and promoting safe operations.

The amendments to subdivision (i) 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(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. The two parts serve different purposes – the first part tests the ability of the casing to withstand anticipated pressure, while the second part is designed to detect fluid migration to verify that there are no current leaks. Thus, these two tests work together to ensure ongoing mechanical integrity of a well.

Subdivision (j) adds 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 for conveying monitoring requirements, which are likely to depend on site-specific concerns. The amendment would promote transparency regarding the Division's regulatory procedures.

Subdivision (k) requires 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 and 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 also enables the Division to audit representations in project approval applications and other reporting regarding injection volumes. The Division's existing regulations do not require operators to maintain this useful information, and the requirements of subdivision (k)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, amendments to **subdivision (l)** update the list of examples of additional requirements that the Division might request on a case-by-case basis. Example five is deleted because it relates to gas storage projects, which are now addressed in separate regulations. (See Cal. Code Regs., tit. 14, sections 1726–1726.10.) Example number seven is added to point to land-surface elevation change measurements, which could be an effective evaluation tool for underground injection projects where subsidence is a concern.

1724.10.1. Mechanical Integrity Testing Part One – Casing Integrity

Section 1724.10.1 provides specifications for the required periodic demonstration of the casing integrity of each injection well. Consistent with existing regulation, **subdivision (a)** requires operators to pressure test an injection well prior to commencing injection and every five years after that. But testing under this section is required more frequently – once every year – if the injection well is a gas disposal well. Gas disposal injection in a well that lacks mechanical integrity would pose significant health and safety risks, and therefore more frequent demonstrate of the integrity of such a well is necessary.

Subdivision (a) replaces the existing requirement to pressure test the "casing-tubing annulus" with a requirement to do a "pressure test of the casing." The existing language assumed the presence of tubing and packer even though the regulations allow certain injection wells, such as cyclic steam and steamflood wells, 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.

Consistent with the operating restriction and incident response requirements identified in section 1724.13, subdivision (a) of section 1724.10.1 prohibits injection in a well that has not been successfully pressure tested within required timeframe. This requirement is necessary to ensure that injection only occurs in wells with demonstrated mechanical integrity. Requiring operators who do not comply with the mechanical testing requirements to halt injection into the noncompliant well is an appropriate consequence with the simultaneous benefits of motivating timely compliance and promoting safe operations.

Subdivision (b) specifies the parameters for conducting required pressures tests and for determining whether a well passes the test:

- Subdivision (b)(1) requires that where injection is through tubing and packer pressure testing must be done in the casing-tubing annulus. This is necessary to demonstrate that the casing will provide an effective secondary mechanical barrier should the tubing or packer fail.

- Subdivisions (b)(2) and (3) 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.
- Subdivision (b)(4) 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.
- Subdivision (b)(5) specifies that the pressure gauge employed must be sufficiently accurate (within 1 percent) and of appropriate scale to effectively indicate whether the well passed or failed the pressure test. Operators are required to submit tests results to the Division in a digital tabular format within 60 days of testing. The actual charts or digital recording of the testing need only be provided if requested.
- Subdivision (b)(6) requires that casing pressure tests are performed at the maximum pressure at which injection will occur, or at 200 pounds per square inch, whichever is greater. However, the operator is not required to pressure test at the calculated maximum pressure that might be allowed under Section 1724.10.3. If testing is not done to the maximum pressure calculated under 1724.10.3, then the maximum allowable surface injection pressure for that well is reduced to the initial pressure for the most recent successful pressure test. Testing at the actual maximum surface injection pressure that might occur is necessary to confirm the well will maintain integrity at the maximum pressure that is allowed.
- Subdivision (b)(7) specifies parameters for determining the depth to which the injection well must be pressure tested, which is necessary to ensure that mechanical integrity is demonstrated for all points of concern within the well. In the limited circumstances where the landed liner is 100 feet or more above the casing shoe, the appropriate testing depth depends on the exact construction of the well and the testing depth will need to be determined on a case-by-case basis.
- Subdivision (b)(8) provides that a pressure test is successful if there is no more than a three percent change in pressure over a continuous 30-minute period, unless the well is a cyclic steam well. For cyclic steam wells, an increase in pressure of as much as 10 percent is allowable as the increase may be attributed to the temperature in the area of the wellbore.
- Subdivision (b)(9) provides that these testing parameters may be modified on a case-by-case basis as needed to ensure an effective test of the integrity of the casing.

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.

The regulations as originally proposed provided a stricter standard for what constitutes a passing pressure test, which was consistent with the pressure testing parameters for gas storage wells that the Division recently adopted. Based on consideration of the relative risk profiles of gas storage wells and injection wells, as well as further consideration of various guidance documents on pressure testing class II injection wells, the Division determined that a shorter pressure test and a greater tolerance for pressure change is equally effective in implementing the regulatory purposes of these regulations and will be less burdensome for operators. The requirement for no more than a three-percent pressure change over a 30-minute pressure test is consistent with guidance issued by US EPA on pressure testing class II injection wells.

Although some jurisdictions may allow operators to inject at pressure beyond what the well has been tested for, it has been the Division's practice to require pressure testing of injection wells at the maximum allowable surface pressure, as this is necessary to confirm the well can hold the maximum pressure at which it is allowed to operate.

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. **Subdivision (c)** 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.

While it is necessary to demonstrate that each injection well will maintain integrity under anticipated operating pressures, pressure testing is not the only way to make that demonstration. **Subdivision (d)** allows for use of alternative mechanical integrity testing instead of pressure testing, provided the alternative method is effective to demonstrate well integrity at the maximum allowable surface injection pressure. While numerous alternative mechanical integrity testing methods that are less burdensome than pressure testing, not all alternative are equally effective. Subdivision (d) provide a nonexclusive list of examples of mechanical integrity testing methods that would might be as effective as pressure testing.

As discussed above, the existing pressure testing requirements have not been consistently applied to all injection wells. Pressure testing generally not been required for injection wells without tubing and packer, in particular steamflood and cyclic steam wells. Recognizing that pressure testing will be significant new compliance burden for many existing underground injection projects, **subdivision (e)** allows time to complete testing. For injection wells that were approved prior to adoption of these regulations and that were previously not required to be pressure tested, operators are not required to complete the first pressure test until April 1, 2024.

The purpose of the pressure testing requirements in section 1724.10.1 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

Section 1724.10.2 augments 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 in making the required demonstration. **Subdivision (a)** would remedy this by specifying that operators can satisfy the requirement by performing the procedures specified in subdivisions (d) through (f) – namely, a radioactive tracer survey, noise log, or temperature survey. Additionally, the regulation allows flexibility for the Division to accept an alternative method. Because operators would have several options to satisfy the requirement as well as the option to propose methods not set forth in the regulation, operators would need to obtain written approval from the Division prior to performing the procedure. This is necessary to ensure that the selected testing method is appropriate in light of any specific concerns with an injection and that the Division is in accord with the operator's testing protocols. Specifying acceptable procedures will make the Division's expectations more transparent, yield higher quality test data, and result in more consistent application of testing standards.

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, subdivision (b) sets testing frequencies based on the type of injection well, but with some changes. The frequency for disposal wells is still every year, for waterflood wells it is still every two years, and for steamflood wells equipped with tubing and packer is still every five years. But for steam flood wells without tubing and packer, the required testing frequency is increased to at least once every two years. The Division considered requiring tubing and packer for steamflood wells, but there are significant technical challenges with steam injection in a well equipped with tubing and packer, and the Division determined that more frequent part-two mechanical integrity testing would be equally effective to achieve the regulatory purposes and significantly less burdensome for operators. 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.

The existing regulation does not specify a frequency for injection wells that are not used for water-disposal, waterflood, or steamflood, and this leave a gap and an ambiguity as to what the required testing frequency for other types of injection wells. Subdivision (b) addresses that ambiguity by establishing a default testing frequency of at least once every two years for all injection wells not specifically addressed in the subdivision. If two years is not the appropriate frequency for a specific injection well or underground injection project, then an alternate frequency may be established under subdivision (c), discussed below.

The lack of specification in the existing regulation regarding part-two testing frequency is most significant 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. And in some areas cyclic steam operations are associated with surface expressions, which can be dangerous and environmentally hazardous. Accordingly, subdivision (b) does not specify a frequency for cyclic steam wells and cyclic steam wells are subject to the default two-year testing frequency.

At the same time, the risk profile of cyclic steam wells can vary greatly. Many cyclic steam wells operate in areas where surface expressions are not a concern and 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.) The definition of “low-use cyclic steam well” in section 1720.1(i) provides bright-line criteria for identifying cyclic steam wells that present a lower level of regulatory concern than other cyclic steam injection wells. Low-use cyclic steam wells inject steam at a frequency and volume that is well below the average for cyclic steam injection wells, and they operate in areas where surface expressions are not a concern. Subdivision (b)(2) specifies a five-year testing frequency for low-use cyclic steam wells, consistent with what is required under existing regulations for steamflood wells. Less frequent part-two testing is appropriate for cyclic steam wells that meet these criteria, and the "low-use cyclic steam well" definition and the specification in subdivision (b)(2) will facilitate a substantially more efficient and consistent process than identifying well-specific and project-specific testing frequencies for these wells under subdivision (c).

As with existing regulation, 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 25 percent within a forty-eight-hour period, unless the operator demonstrates to the Division that the variance was the result of an issue that does not relate to well integrity." Based on the Division's experience with project-specific requirements, a 25 percent pressure variance is an effective threshold for flagging anomalies for investigation.

The testing methods and frequencies set forth in subdivision (b) are intended to be the default requirements that 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, is 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. **Subdivision (c)** allows the Division to approve testing methods and frequencies that differ from the defaults set forth in this 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.

Subdivisions (d), (e), and (f) specifies 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.

Subdivision (g) requires operators to take immediate action to investigate any anomalies encountered during the “part two” mechanical integrity. It also requires 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 is consistent with 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 on mechanical integrity testing as well, to ensure operators are fully aware of their responsibilities in the event of anomalous testing results.

Mechanical integrity testing, as required under 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. Pressure testing tests the ability of the casing to withstand anticipated pressure, while “part two” testing is designed to detect fluid migration to verify that there are no current leaks. Thus, these two tests work together to ensure ongoing mechanical integrity of a well. Effective mechanical integrity testing requirements under 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. section 1724.10.3 amends these requirements to specify the formula for calculating the MASP, to ensure that MASP is in every case supported by sound data and analysis, to allow necessary flexibility for the Division to approve and MASP above fracture pressure in specific circumstances, and to establish consistent protocols for conducting step rate tests.

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, this subdivision will 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. Any friction factor must be calculated based on the new coated tubing of the largest diameter that will be used for injection to ensure that the calculation is conservative and does not result in unapproved injection above fracture pressure.

Subdivision (b)(1) provides that the MASP for an injection well must only be as high as the pressure at which it was last successfully pressure tested. This both prevents injection at untested pressures and allows operators to test at lower pressures if the injection well will not be operated at pressures as high as the calculated maximum pressure. The two exceptions to this rule are if the operator has demonstrated the wells integrity at the calculated maximum pressure by means other than pressure testing or if the operator is implementing alternative pressure monitoring under section 1724.10.1(c).

Subdivision (b) allows 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 approve 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, section 1724.10.3 allows for MASP determinations based on a conservative estimate of the fracture gradient in the area that the well is drilled, but **subdivision (c)** requires 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 subdivision (c), or if the operator wishes to establish a higher well-specific fracture gradient, then **subdivision (d)** requires well-specific step rate test data to support the MASP determination for that well. These requirements, which apply to new and existing injection wells, are necessary to ensure that MASP is based on sound science and data in every case.

Subdivision (e) establishes required standards and protocols for conducting step rate tests under this section. Consistent with guidance from US EPA Region VIII, 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; and
- Formation breakover must be clearly demonstrated.

Subdivision (e) also includes specifications for noticing 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 required protocols of subdivision (e) will result in more complete project data and more appropriate MASPs. In turn, more appropriate MASPs will 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. 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 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.

1724.10.4. Continuous Pressure Monitoring

The Division's existing regulations require that injection wells be equipped for installation of a pressure gauge or pressure recording device. Those requirements are removed from section 1724.10, and replaced with section 1724.10.4, which modernizes the requirement by calling for operators to continuously record injection pressures at all times that a well is injecting.

The monitoring and data collection from continuous injection pressure recording will facilitate effective regulation of injection operations in terms of both incident response and compliance verification. Investigation of incidents such as surface expressions or concerns about potential groundwater contamination will benefit from continuous injection pressure data. The Division will have more a complete picture of operational practices surrounding the incident or concern allowing for higher quality diagnostics and root cause analysis. The data will also enable the Division to verify compliance with other injection reporting requirements, particularly maximum allowable surface injection pressure (MASP) requirements. To facilitate the Division's rapidly flagging MASP compliance concerns, operators are required to report the highest instantaneous injection pressure for each injection well each month. The current requirement that a pressure gauge or recording device "be available at all times" does not yield useful data for such investigations and compliance checks. 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.

To ensure that the injection pressure data is available when it might be needed for the Division's investigations, operators are required to maintain the data so long as the well is approved for injection, and for three years after that.

Section 1724.10.4 incorporates alternatives that reduce the burden of compliance but are equally effective in accomplishing the regulatory goals. If the injection facilities for an injection well are configured in a manner that effectively prevents injection above the maximum allowable surface injection pressure, then the necessity for continuous injection pressure is largely addressed and the Division may waive the requirement for that well. And an operator may suspend continuous injection pressure recording for a well while the well is disconnected from all injection lines. Although the requirement is for well-specific pressure monitoring and recording, the requirement may be satisfied by recording injection pressure from a header or manifold, if the operator demonstrates the ability to calculate well-specific injection pressures from the recorded data. Although the continuous pressure monitoring and recording requirements may be satisfied with a supervisory control and data acquisition system (commonly referred to as "SCADA"), the use of such a system is not prescribed. Any effective digital or analog recording device may be used to satisfy the continuous pressure monitoring and recording requirements.

Recognizing that for many existing injection wells new equipment will be needed to comply with these requirements, operators are allowed until April 1, 2021, to meet the new requirements. In the interim, operators are required to continue to comply with the existing requirement to ensure that an accurate, operating pressure gauge or pressure recording device is available at all times, and that injection wells are equipped for installation and operation of such gauge or device.

The requirements in section 1724.10.4 for continuous monitoring and recording of injection pressures 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. These requirements will yield data essential to effective investigation of incidents and allow the Division to verify compliance with other critical underground injection control requirements.

1724.11. Surface Expression Prevention and Response

Section 1724.11, **subdivision (a)**, codifies in regulation the Division's policy that underground injection operations not result in surface expressions. The term "surface expression" is defined in the regulations (section 1720.1, subdivision (n)) 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, that is outside of a wellbore 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 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.

Subdivision (b) sets forth preventative monitoring requirements that apply to all underground injection projects that, in the Division's judgment, have been known 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 24-hours a day on-site staff, daily visual inspections, continuous monitoring of steam injection rates to assess for variances, and a surface expression monitoring and prevention plan. The plan must include the use of a ground monitoring system or a real-time pressure/flow monitoring system, a map of the project area, protocols for restricting access, and training for field personnel. 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 regulation requires the operator to cease injecting into nearby injection wells in order to mitigate the threat. Injection would then be prohibited until the Division provides written approval to resume. The requirements of 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 regulation helps to prevent surface expressions from occurring and promotes consistent application of standards.

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

Subdivision (d) requires automatic cessation of injection at wells where the wellhead is located within a 150-foot radius of a surface expression. If the surface expression continues to flow for more than 24 hours, the cessation radius doubles to 300 feet, and doubles again to 600 feet if the expression continues for more than five days. After ten days of ongoing flow from a surface expression, the Division determines the expanded cessation radius. **Subdivision (e)** acknowledges and preserves 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 to a surface expression, the more likely that well is causing or contributing to its existence. The requirement is also intended and is necessary to increase the consequences for causing surface expressions. Automatic cessation requirements incentivize safer, more prudent injection activities, proactively discouraging at the outset oilfield practices that can lead to surface expressions.

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

Subdivision (h) requires 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.

Subdivision (i) requires operators to restrict access to areas containing surface expressions and to mark those areas with appropriate signs. The signs 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 promotes public safety in the field and is necessary to ensure consistent safety practices as required by applicable Cal/OSHA regulations.

Subdivision (j) excludes low-energy seeps (defined in section 1720.1, subdivision (h)) from the prohibition of subdivision (a) of this section and the response requirements of subdivisions (d) through (g). Where a surface expression meets the requirements of a low-energy seep—meaning that the operator has demonstrated to the Division that the fluid coming to the surface is low energy, low temperature, not injected fluid, and contained and monitored in a manner that prevents damage to life, health, property, and natural resources—the surface expression presents different, generally lesser, regulatory concerns than do other surface expressions. Therefore, low-energy seeps will not be considered violations under subdivision (a) and are subject to reduced response requirements. Whether or not a surface expression is a low-energy seep has no effect on the preventative requirements of subdivision (b).

Subdivision (k) requires 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.

Section 1724.11 mitigates 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

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

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

Subdivision (a)(4) requires operators to monitor and record the surface expression and containment measures daily (or less frequently if approved by the Division), notify the Division of any changes, and maintain records for the duration of the surface expression. Such monitoring, notification, and recordkeeping is 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.

Subdivision (a)(5) requires operators to map, mark, and restrict access to containment measures in the field. This requirement promotes the safety of industry workers, Division employees, and the public.

Finally, **subdivision (b)** has been added to clarify that, notwithstanding the containment measures outlined in this section, surface expressions are a violation of Section 1724.11(a).

This section improves 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. This 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

Section 1724.13, **subdivision (a)**, specifies a list of circumstances that require operators to notify the Division and cease injection until the Division authorizes resumption. Some of the circumstances, such as a failed mechanical integrity test, visible surface damage or erosion, 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 timeframe and failure to submit injection and production reports, are intended to impose stronger consequences for noncompliance with testing and reporting requirements. Finally, subdivision (a) requires operators to cease injection and notify the Division when a well has become an idle well. This requirement is designed to ensure that the Division is notified before injection begins in any well that has attained idle well status, as it is not uncommon for extended period of inactivity to correspond to neglect with regard to maintenance and compliance. However, an operator may maintain approval for an injection well while it is idle by communicating with the Division. With respect to all circumstances listed in subdivision (a), the Division finds that operators are required to cease injection on their own initiative rather than wait for the Division to follow up with such directions.

Subdivision (b) requires operators to comply with all operational and remedial directives of the Division related to the reason for ceasing injection and requires that operators not resume injection until they receive written approval from the Division.

These regulations 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 that violate those requirements sometimes continue operations until the Division issues a remedial order.

This section, on the other hand, creates clear, immediate, and consequential obligations for operators to cease injection if the well is not in compliance with the specified requirements. Operators that continue to inject in violation of this section are separately liable for violating this section, in addition to the underlying violation (if applicable) that triggered the obligation to cease injection. The Division anticipates that this section will improve operator compliance with reporting and testing requirements. This 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 **subdivision (c)** is to notify operators that each day of injections in violation of 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.) Subdivision (c) is intended and necessary to promote transparency regarding how the Division plans to assess violations. Subdivision (c) also includes a cross reference to Section 1777(c)(4) because that section's requirement to disconnect injection lines in the absence of Division approval might be triggered in addition to the requirements of this section. Treating each day of injection as a separate violation is also necessary to provide adequate disincentives to noncompliance.

Article 5. Requirements for Underground Gas Storage Projects

Within title 14, division 2, chapter 4, subchapter 1, the proposed rulemaking would renumber the existing article 4, titled "Requirements for Underground Gas Storage Projects," to become article 5. A newly created article, titled "Underground Injection Control," would become the new article 4. This change is purely a renumbering. The purpose is to accommodate organization of certain regulatory sections governing underground injection control within a specific article while still minimizing disruptive changes to the existing section numbers of the regulations. The renumbering of this article has no substantive regulatory effect.

1748. Underground Injection Control

The existing section 1748 identifies regulatory sections with specific application to offshore disposal and injection projects. The amended section 1748 will update the regulatory text to reflect the definition of "underground injection project" provided in section 1721.1, subdivision (m). Section 1748 also updates 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 section 1724.7. Under section 1748, these provisions of article 4 will 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 section 1748, these provisions of Article 4 will 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.

NONSUBSTANTIAL CHANGES

The following nonsubstantial changes have been made in the final text of the regulations that were not included in the originally proposed regulations or the modifications to the proposed regulations when they were made available for public comment:

- In section 1724.8, subdivision (a)(1), the word "an" has been added where it was inadvertently omitted from the phrase "approval of underground injection project." As modified, the phrase now reads, in pertinent portion: "approval for an underground injection project…."

- In section 1724.10, subdivision (b), the phrase "if the packer or tubing in an injection is set, reset, moved or changed" has been modified by adding the word "well" and adding a comma after the word "moved." As modified, the phrase now reads: "if the packer or tubing in an injection well is set, reset, moved, or changed."

- In section 1724.10, subdivision (e), the phrase 'five hundred linear feet" has been changed to "500 linear feet."

- In section 1724.10, subdivision (g)(2), the word "packing" has been changed to "packer."

- In section 1724.10, subdivision (g)(3), the words "well" and "and" have been added where they were inadvertently omitted from the sentence. As modified, the sentence now reads: "An injection well that was not required to be equipped with tubing and packer prior to April 1, 2019, is not subject to the requirements of this subdivision until April 1, 2021."

- In section 1724.10.1, subdivision (b)(7), the two instances of the phrase "cement casing" have been changed to "cemented casing."

- In section 1724.10.1, subdivision (c)(2)(C), an incorrect cross-reference to a non-existent "subdivision (d)(2)(B)" has been corrected to "subdivision (c)(2)(B)."

- In section 1724.10.2, a missing comma has been added after the word "tubing" in the title of the section.

- In section 1724.10.3, subdivision (e)(3), several instances of the percent symbol, "%," have been replaced by the word "percent." As modified, the pertinent text now reads: "Suggested step pressures are 5, 10, 20, 40, 60, 80, and then 100 percent of the proposed injection rate, or until formation breakdown."

- In section 1724.11, subdivision (b)(1)(C), the phrase "access to in areas where there are surface expressions" has been modified by deleting the word "in." As modified, the phrase now reads: "access to areas where there are surface expressions…."

- In Section 1724.11, two different subdivisions within the same sequence were labeled as "subdivision (j)" The second instance of subdivision (j) has been changed to "subdivision (k)."

- In section 1724.12, subdivision (b), an incorrect cross-reference to "Section 1714.11(a)" has been changed to "Section 1724.11(a)."

LOCAL MANDATE DETERMINATION

The adoption of this rulemaking does not impose a mandate on local agencies or school districts.

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, which has been provided to the 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 to the Initial Statement of Reasons for this rulemaking action, and those documents are hereby incorporated by reference into this document.

DETERMINATION REGARDING ALTENATIVES CONSIDERED

In the course of developing the proposed regulations, the Division considered various alternative approaches and suggestions presented in the stakeholder comments. Public input during the multiple pre-rulemaking engagements helped to steer initial development of the proposed regulations, and the Division made a number of revisions to the originally proposed regulations in response to the additional public input received during the rulemaking process.

The Division has determined that no alternative to the final text of the regulations would be more effective in carrying out the purpose for which the regulations are proposed, as effective and less burdensome to affected private persons than the adopted regulations, or more cost effective to affected private persons and equally effective in implementing relevant statutory policy or other provisions of law. This determination is based in part upon the SRIA completed for this rulemaking action and the statement of benefits in the Notice of Proposed Rulemaking Action. Following is further supporting information for this determination and the Division's reasons for rejecting alternatives that were proposed and considered, including alternatives that might lessen the adverse economic impact on small businesses:

- The Division considered but rejected various alternative parameters for the default "part one" mechanical integrity testing requirements. As discussed above, the intent of the "part one" test is to validate the ability of the well casing to serve as a mechanical barrier to fluid migration at the maximum pressure allowed during actual operations. Although some regulatory entities in other jurisdictions allow injection at pressures greater than those required for testing, such testing would not be as effective at providing assurance of casing integrity under actual operating conditions. Testing less frequently than the default of at least once every five years or for less than a thirty-minute period would not provide a comparable and adequate assurance of early problem detection. At the same time, because mechanical integrity testing can itself be a source of wear on a well and has the potential to disrupt normal operations, more frequent or longer duration testing may provide less value relative to the additional risk and burden on operators it creates. No variation of "part one" mechanical integrity testing parameters examined by the Division would as effective or more effective in accomplishing the purposes of these regulations while also being equally or less burdensome to the regulated community.

- The Division considered but rejected a more prescriptive fixed schedule for the required liquid analysis of injected liquids. Section 1724.10, subdivision (d), requires operators to submit updated liquid analysis based on compliance with a performance standard: whenever a change in the contributing sources renders the liquid analysis on file with the Division meets no longer representative of the liquid actually injected. This section also requires operators to submit updated liquid analysis upon request from the Division. Requiring more frequent liquid analysis by default would increase the burden of the regulations while providing data of limited or unclear benefit. That alternative would be more burdensome for operators and would not be more effective in carrying out the purpose of these regulations.

- The Division considered but rejected including various additional analytes as part of the baseline procedure for liquid analyses required by the underground injection control regulations. As described above, the purpose of the liquid analsis requirements is to provide the Division and the State Water Resources Control Board with information to evaluate what effects an underground injection project will have on the subsurface reservoir receiving injected fluid. The Division consulted with the State Water Resources Control Board to identify a list of the most broadly informative analytes, given the nature and location of the liquids. The addition of analytes beyond those in the regulation would increase the complexity and expense of testing, but would not provide information that is as reliably useful for the relevant regulatory analyses. In specific situations where additional liquid analysis analytes are necessary to evaluate an underground injection project, the regulations expressly contemplate that the Division can and will require supplementary testing on a case-by-case basis. No variation of the baseline liquid analysis analytes examined by the Division would as effective or more effective in accomplishing the purposes of these regulations while also being equally or less burdensome to the regulated community.

- The Division considered but rejected requiring operators to monitor and report seismic activity near each underground injection project. After reviewing public comments and further exploring available resources, the Division concluded that centralized tracking and analysis of seismic information by a government sponsored agency will provide a more accurate and cost-effective solution than would requiring each operator of injection wells to track and report publicly-available seismic information on an individual basis. Accordingly, that alternative would be more burdensome for operators and would not be more effective in carrying out the purposes of these regulations.

- The Division considered but rejected various changes to the project data requirements that would have called for more, for less, or for different baseline information. To facilitate timely and efficient execution of the Division's regulatory mission, it is essential that each underground injection project be supported by a reliable and relatively standardized set of baseline geologic, engineering, and operational information. The data submittal requirements in section 1724.7 are necessary to ensure that the Division receives this standardized baseline supporting information for each underground injection project. Requiring less data or allowing greater flexibility in the type of data required would not accomplish a comparable and satisfactory level of standardization. Where additional data beyond the baseline may be necessary for evaluation of a specific project, the regulations expressly contemplate that the Division can and will require the operator to provide additional data on a case-by-case basis. Likewise, in unusual situations where obtaining the baseline data may present an unreasonable burden, the regulations expressly contemplate that the Division may on a case-by-case basis accept equally effective alternative data to demonstrate compliance with the regulatory performance standard for project evaluation. No variation of the baseline project data requirements examined by the Division would as effective or more effective in accomplishing the purposes of these regulations while also being equally or less burdensome to the regulated community.

- The Division considered but rejected requiring groundwater monitoring for all underground injection projects, as an additional measure for evaluating the ongoing efficacy of injected fluid confinement. The regulations contemplate implementation of groundwater monitoring requirements for underground injection projects on a case-by-case basis, as determined through evaluation of each project by the Division, the State Water Resources Control Board, and the appropriate Regional Water Quality Control Board. Although groundwater monitoring is a possible tool for responding to indication of a lack of fluid confinement, the additional benefits of making groundwater monitoring a categorical requirement for all underground injection projects are not clear. That alternative would be more burdensome for operators and would not be more effective in carrying out the purposes of these regulations.

- The Division considered but rejected requiring a surface expression prevention and response plan for every underground injection project. The regulations require a surface expression monitoring and prevention plan for underground injection projects recognized to be more prone to surface expressions, either because the project has a known history of causing a surface expression or because the project involves injecting steam into a diatomite formation. The objective of this requirement is to ensure that underground injection projects are operated so as to avoid causing surface expressions, and to contain surface expressions safely if they do occur. A categorical requirement for every operator to develop and implement a plan for preventing and responding to surface expressions, without consideration for whether and to what extent the specific underground injection project presents a risk of causing surface expressions, would add a burden on operators without providing a clear benefit in carrying out the purposes of these regulations.

- The Division considered but rejected prescribing a categorical exemption for cyclic steam wells from the default requirement for continuous recording of well-specific injection pressure. The primary purpose of the continuous monitoring requirement is to ensure and document that the actual injection pressure does not exceed the maximum allowable surface injection pressure. In many cases, injection above the maximum allowable surface injection pressure increases a variety of risk factors for underground injection projects and effective confinement of injected fluids. While cyclic steam injection wells typically engage in active injection less frequently than other types of injection wells, the regulatory concerns regarding injection above the maximum allowable surface injection pressure remain largely the same. This alternative would not be as effective in accomplishing the purposes of these regulations.

- The Division considered but rejected allowing more than or less than two years for operators to bring underground injection projects into compliance with the requirement for continuous recording of well-specific injection pressure. The two-year timeframe for compliance is informed by the Division's Standardized Regulatory Impact Assessment for this rulemaking and by discussions with operators about feasible timeframes for obtaining the necessary equipment and completing installations. Without the standardized availability of continuously recorded injection pressure data, the Division's abilities to verify compliance with project approval conditions and to conduct incident response are lessened. However, because the requirement for continuous well-specific injection pressure monitoring is a substantial change from the existing requirement, many existing facilities will need new equipment. Compelling immediate or more rapid compliance with the new requirement would create a large temporary burden on operators out of proportion to the temporary benefit of the earlier availability of better supporting data. Both longer and shorter compliance timeframes therefore would not be as effective or more effective in accomplishing the purposes of these regulations while also being equally or less burdensome to the regulated community.

- The Division considered, but rejected, only requiring mechanical integrity testing for injection wells that penetrate an underground source of drinking water (USDW). Although USDW is one of the resources which must be protected, it is not the only resource. When determining the extent of the approved injection zone, the Division's primary focus is protection of USDW, but the location of USDWs is not the only factor in determining the extent of the approved injection zone. The approved injection zone may reflect a conservative buffer around a USDW zone, there may be a need to protect groundwater that does not meet the definition of a USDW, and hydrocarbon reservoirs must be protected from infiltrating water or other detrimental substances. Foregoing mechanical integrity testing for injection wells would not be as effective to carry out the purposes of these regulations.

- The Division considered, but rejected, requiring tubing and packer on all wells, including steam flood and cyclic steam wells. Although injection through tubing and packer is preferable, it is not always technically possible for some well configurations. Some slimmer profile holes may not have space for tubing and packer and some well configurations function better without tubing and packer in place. The Division believes that the mechanical integrity testing, monitoring, and evaluation requirements of these regulations will provide a highly effective regulatory framework for injection operations, even in circumstances where injection wells are operated without the benefit of a secondary mechanical barrier.

- The Division considered, but rejected, a requirement for disclosure of chemical additive information for all wells. Instead, the regulations will require disclosure only where the well is within 500 feet of the screen or perforations of a water supply well or a greater distance if, in the Division's judgment, geological conditions or the relative location of any water supply well warrants the additional data collection; disclosure which may be necessary to investigate any potential contamination of the water supply well. Requiring additive disclosure for all injection wells would be more burdensome for affected operators and would not be more effective to carry out the purposes of the regulations.

- The Division considered, but rejected, removing the requirement for 100 psi of positive pressure for the alternative monitoring option available for Part I mechanical integrity testing. Positive pressure on the backside is necessary to detect small leaks, especially from the packer, which may not be detectable with fluid level tests. Alternatives to maintaining positive pressure on the backside would not be as effective to carry out the purposes of these regulations.

- The Division considered, but rejected, requiring a step-rate test in each well to determine its maximum allowable surface injection pressure. Section 1724.10.3 allows for maximum allowable surface injection pressure determinations based on a conservative estimate of the fracture gradient in the area that the well is drilled, but subdivision requires that such an estimate be adequately supported by representative step-rate test data or other testing or geologic data. If data and analysis demonstrate that the estimate employed is below the actual fracture gradient, then use of the estimate is appropriate. Requiring a step-rate test in those circumstances would be more burdensome for affected operators and would not be more effective to carry out the purposes of these regulations.

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).
- New Mexico Oil Conservation Division, Underground Injection Control Program Manual, dated February 26, 2004.
- United States Environmental Protection Agency, Region 5, Regional Guidance #5: "Determination of the Mechanical Integrity of Injection Wells," revised February 2008.
- Government of Saskatchewan, Annulus Test Reporting Requirements, Guideline PNG 029, revised November 2015.
- BC Oil and Gas Commission, Water Service Wells Summary Information, October 2017.
- Alberta Energy Regulator, Interim Directive ID 2003-01, January 30, 2003.
- David M. Nielsen & Linda Aller, United States Environmental Protection Agency, Methods for Determining the Mechanical Integrity of Class II Injection Wells, July 1984.

SUMMARY OF AND RESPONSE TO PUBLIC COMMENTS RECEIVED

Public comment summaries and responses for the initial public comment period held from July 27, 2018 through September 13, 2018 can be found under Tab M in the rulemaking file. Public comment summaries and responses for the 15-day public comment period held from October 29, 2018 through November 14, 2018 can be found under Tab N in the rulemaking file. These separate documents are all hereby incorporated by reference into this document.