UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

FIRST FIFTEEN DAY
PUBLIC COMMENT SUMMARY AND RESPONSE

First Fifteen Day Public Comment Period:
October 29, 2018 – November 14, 2018

INTRODUCTION

The following comments, objections, and recommendations were made regarding the proposed Updated Underground Injection Control Regulations rulemaking action during the first fifteen-day public comment period beginning October 29, 2018 and ending November 14, 2018.

Over the course of the public comment period, the Division received a number of public comments via email, regular mail, public comment hearing, and fax. These comments ranged from detailed comments on the proposed requirements to general concerns about groundwater protection.

To facilitate the process of reviewing and responding to comments, the Division assigned a unique numerical signifier to each comment. This signifier consists of three components: first, a unique code number assigned to each commenter; second, a separating hyphen; third, a sequential number assigned to each comment from the identified commenter. The chart below lists the code number for each commenter. Within this document, you will find either grouped or individual numerical signifiers, followed by a summary or specific comment, followed by a response (italicized).

COMMENTERS

Number	Name and/or Entity
0001	Chevron
0002	State Building and Construction Trades Council of California
0003	Clean Water Action
0004	Tom Williams
0005	Southern California Gas Company
0006	Western States Petroleum Association
0007	E&B Resources
0008	MacPherson
0009	Environmental Defense Fund and Environmental Working Group
0010	Aera Energy
0011	National Resources Defense Council
0012	California Resources Corporation
0013	Center for Biological Diversity
0014	California Independent Producers Association
0015	Sentinel Peak Resources

ACRONYMS

AE	Aquifer Exemption
AOR	Area of Review
API	American Petroleum Institute
CASRN	Chemical Abstracts Service Registry Number
CFR	Code of Federal Regulations
CCR	California Code of Regulations
Division	Department of Conservation, Division of Oil, Gas, and Geothermal
DOGGR	Department of Conservation, Division of Oil, Gas, and Geothermal
EOR	Enhanced Oil Recovery
Legislature	Legislature of the State of California
OES	California Governor's Office of Emergency Services
OSHA	Occupational Safety and Health Administration
MASP	Maximum Allowable Surface Pressure
MOA	Memorandum of Agreement
MIT	Mechanical Integrity Testing
NTO	Notice to Operators
PAL	Project Approval Letter
PRC	Public Resources Code
SB 4	Senate Bill 4 (2013-2014)
SB 1281	Senate Bill 1281 (2013-2014)
SCADA	Supervisory Control and Data Acquisition
SDWA	Safe Drinking Water Act (Federal)
SRIA	Standardized Regulatory Impact Assessment
SWRCB	State Water Resources Control Board
TDS mg/L	Total Dissolved Solids mg/L
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
US EPA	United States Environmental Protection Agency

GENERAL COMMENTS

Comments in Support

0003-9 Commenters continue to support the flexibility on timing for approval of injection projects, and would oppose any time limits for the Division, or any other agency involved in oversight, to review permit applications or other documents.
0011-15 1724.6(a) and (b): Commenter supports the proposed revisions.
0011-16 1724.10(b): Commenter supports the proposed addition of the requirement to notify the Division and conduct testing if the packer or tubing in an injection well is set, reset, moved or changed.
0011-17 1724.10(i)(5) and (l)(7): Commenter supports the proposed additions.
0011-18 1724.10.1(a)-(c): Commenter generally supports the proposed revisions to these subsections.
0009-1 Commenters support enhancements to the Area of Review definition to ensure it is at least as broad as the area of influence, and a new section on remediation requirements upon a failure of MIT Parts I or II attesting.
Response to Comment 0003-9, 0011-15, 0011-16, 0011-17, 0011-18, 0009-1: ACCEPTED. *Thank you for your comments.*

General Opposition

0012-1 Commenter has invested in Division-approved automation and alarm systems, and in 24/7 monitoring by operators at our key fields. The Division's existing test pressures, schedules, acceptance criteria and variances for Commenter’s operations reflect both the recovery methods and formations where we operate and the additional safety factor from Commenter’s investments in automation and alarm systems and in on-site monitoring by trained personnel. We believe that the Division's updated regulations should incorporate and maintain existing UIC testing and monitoring requirements that reflect our significant investments in Division-approved systems and that recognize the diversity of Commenter’s UIC operations across the state.
Response to Comment 0012-1: NOT ACCEPTED. *The Division believes the proposed requirements will result in improved safety and are better aligned with the commitments expressed in the Primacy Agreement with US EPA. The Division’s existing regulations require considerable case-by-case interpretation to identify appropriate project-specific requirements. Over time, this has led to a general lack of transparency and inconsistent application of requirements, and, in some cases, aging regulatory constructs that have not kept up with changing oil production methods and advancements in the understanding of threats to health, safety, and the environment. While the proposed regulations do include flexible, performance-based requirements in several instances, they address many of these identified problems.*

0012-3 The Division has also approved numerous testing exemptions or variances for specific UIC projects that take local conditions into account. We request that the Division review and maintain these, potentially in conjunction with more frequent tracer surveys to confirm the conditions underlying the variance. In this way, the Division and operators can devote UIC testing resources to higher priority wells. For the same reason, continuous monitoring should be phased in first for UIC wells that penetrate USDW during the 2-year implementation period, with a 4-year implementation period for other UIC wells. This will help operators and the Division to apply resources to higher priorities and not interfere with ongoing investments in facility upgrades.
Response to Comment 0012-3: NOT ACCEPTED. *The proposed regulations provide opportunities for alternatives to the default requirements where appropriate and safe. The Division's existing regulations require considerable case-by-case interpretation to identify appropriate project-specific requirements. Over time, this has led to a general lack of transparency and inconsistent application of requirements, and, in some cases, aging regulatory constructs that have not kept up with changing oil production methods and advancements in the understanding of threats to health, safety, and the environment. Thus, existing variances cannot be maintained unless they are consistent with the alternative showing required in the proposed regulations. The purpose of continuous monitoring is to create a record showing that injection is taking place at or below MASP; the presence or absence of USDW is irrelevant to this purpose and cannot affect the requirement.*
0015-4 Commenter fully appreciates the need to protect USDW by regular testing of continuous injection wells. We also appreciate that mobilizing equipment and manpower on the scale demanded by these draft regulations does not come without risk or impacts of their own. We urge you to consider regulations in light of the fact that not a single incident of groundwater impacts attributable to oil and gas operations has been identified.
Response to Comment 0015-4: ACCEPTED. *The Division has proposed these regulations after taking into account the risks and impacts associated with enhanced oil recovery and produced water disposal. The Division evaluated both less burdensome as well as more rigorous requirements and believes the proposed regulations strike the right balance relative to potential risks.*
0002-1 These regulations exceed testing pressures applied by the US EPA and other state regulators. Enacting new regulations that far exceed testing protocols only makes California a more difficult place to conduct business, and consequentially, makes it a more difficult place to encourage investment and employment. Absent compelling evidence that existing UIC regulations do not protect Californians, we are weary of any protocols that further discourage investment in California's workforce and economy. As such, Commenters endorse comment letter 0012 and urge the changes requested therein to ensure that the updated UIC regulations apply test pressures that conform to multi-state regulatory and industry standards and maintain reasonable acceptance criteria that have served the Division and the state well in its existing UIC regulations. Imposing infeasible testing requirements unnecessarily diverts resources away from upgrading key fields, threatening the state's production and increasing our dependence on imports from foreign countries with poor environmental and human rights records.

Response to Comment 0002-1: NOT ACCEPTED. *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 guidances 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 are less burdensome than pressure testing, not all alternatives are equally effective. Subdivision (d) provide a nonexclusive list of examples of mechanical integrity testing methods that would be as effective as pressure testing.

0009-2

As in past rounds of comments, we continue to advocate for a standard of universal annular pressure monitoring as an accompaniment to, and not a replacement for, universal pressure testing as part of establishing internal mechanical integrity. As DOGGR's options for meeting the MIT Part I requirement multiply, the commenters urge DOGGR to hew as closely to the principle of pressure testing and annular pressure monitoring for as many wells as is feasible.

Response to Comment 0009-2: NOT ACCEPTED. *Continuous annular pressure monitoring is unlikely to be feasible without a SCADA system. While some UIC projects already operate with a SCADA system, the majority do not, and the substantial capital investment cannot be justified for lower risk injection wells. As far as test pressure is concerned, operators will only be allowed to inject up to the maximum pressure tested; thus, their maximum pressure tested becomes their maximum allowable surface injection pressure. All anomalous pressure incidents require immediate reporting to the Division.*
0004-1 Every new or rework permit and every data submission within the UIC Project/Area of Reference (UIC & AOR) must include a requirement for the applicant and an independent certified engineer to verify and confirm that the well is "AS-IS" – "AS-BUILT" – "AS PERMITTED", before any modification, reworking, plugging, abandonment, or other design changes can be considered. A cover page with contractors, operators and owners certifying that they have reviewed and confirm all data and analyses should be required for each submission.
Response to Comment 0004-1: NOT ACCEPTED. *Requiring that all data be verified independently as a part of each step of the permitting process and data submission would add substantial complexity, burden, and ambiguity to the proposed regulations without clear benefit.*
0004-2 As the Division is responsible for changes of well designs within any subsurface lease, the Division must incorporate individual and corporate shares of the applicant, operator, lessee, and leaser responsibilities into any new or changes of permitted well design and operation. Operator-Lessee-Owner Corporate practices must clearly assign longer term responsibilities for failure of facilities through unpermitted changes or modifications of approved designs. All subsurface property owners must be signatories for future liabilities/responsibilities for each AOR.
0004-4 Subsurface and surface ownerships and boundaries must be coincident with those of the AOR.
Response to Comments 0004-2 and 0004-4: NOT ACCEPTED. *Mineral rights and leasing agreements are not the subject of the proposed regulations. The responsibilities of prior operators with respect to abandonment of wells is governed by existing law. See, e.g., PRC section 3237.*
0013-10 The Proposed Regulations now contain, for the first time, an express exemption for gas disposal wells. But it is not accompanied by any reasoning behind this exemption. This new exemption is a new and significant departure from existing UIC regulations and must be evaluated and justified before adoption.
Response to Comment 0013-10: NOT ACCEPTED. *The proposed regulations do not provide an "exemption" for gas disposal wells. On the contrary, to the extent the proposed regulations distinguish gas disposal wells, it is to assign a more restrictive requirement. The phrase "gas disposal well" only appears in the regulations in: 1724.10.1(a) where it specifies that gas disposal wells must be subject to a pressure test at least once per year rather than the once per five years schedule applicable to other types of injection wells; 1724.10.1(e) where gas disposals wells are singled out for an earlier compliance deadline than other types of injection wells; and 1724.10.2(d)(2) to clarify that the casing tubing annulus valve does not need to be left open on a gas disposal well during a radioactive tracer survey. If commenter was referring to the specific exemption for underground gas storage wells, under*

existing regulation these wells are subject to a different, specific set of requirements under sections 1726 through 1726.10.
0013-11 Oil and gas in California is an environmental justice issue. Low income communities of color have historically borne a disproportionate burden of exposure to oil and gas pollution. In California, of the 5.4 million residents living within one mile of a well, nearly 69 percent are people of color. According to the Natural Resources Defense Council's analysis using CalEnviroScreen 2.0, one-third of people who live within a mile of a well—1.8 million people—live in communities that already shoulder a disproportionate amount of the state's air, water and soil pollution as a result of living close to industrial facilities, transportation corridors, hazardous waste facilities and toxic clean-up sites. Nearly 92 percent of those residents are people of color (69 percent Latino/Hispanic, 11 percent Asian, 10 percent African American and 2 percent other)
Response to Comment 0013-11 ***NOT ACCEPTED.*** *The Division routinely solicits input from all interested members of the public, and particularly welcomes comments from the residents of communities situated near oil and gas operations. Consistent with the Division's April 1981 "Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act," and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. The Division does not see a need to codify this policy within the proposed regulations. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency.*
0004-22 1724.6(d), 1724.7(a), 1724.10.1(c)(2)(E), 1724.10.2(g), 1724.10.3(a): Division goals are changing but must be consistent within the regulations; revise to life, health, safety, property, environment, and natural resources; or state at the beginning as goals and use "Division Goals" elsewhere.
Response to Comment 0004-22: NOT ACCEPTED. *Proposed section 1724.5 articulates the purpose, scope, and applicability of the underground injection control regulations. PRC section 3106 broadly defines the legislatively directed regulatory mission of the Division.*

AOR Requirements

0004-3 All UIC injection and production wells in an Area of Reference (AOR) must be included in the UIC project permit.
Response to Comment 0004-3: NOT ACCEPTED. *The commenter was most likely referring to the Area of Review, rather than "Reference." The engineering study component of the section 1724.7 project data requirements already requires a map and other identifying information for all wells within and adjacent to the boundary of the area of review.*

0004-5 Well paths and the AOR must include the 1250 ft radii from the wellhead and the entire well/borehole path.
Response to Comment 0004-5: NOT ACCEPTED. *The area of review is the calculated lateral distance where the migration of injection or reservoir fluid can be anticipated. The Division does not see any justification for a fixed radius that may or may not account for project operations.*
0004-9 A local stakeholder group must be formed, and the Division must coordinate and provide information/updates for each AOR.
Response to Comment 0004-9: NOT ACCEPTED. *Consistent with the Division's April 1981 "Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act," and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. The Division does not see a need to codify this policy within the proposed regulations. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency.*
0004-10 Abandonment/plugging/idling procedure/process for an AOR must be provided for.
Response to Comment 0004-10: NOT ACCEPTED. *As described more fully in the Notice of Proposed Rulemaking Action, the purpose of this rulemaking action is to update the Division's specific regulatory requirements for underground injection projects. Broad strokes revision of the existing statewide requirements for plugging and abandonment of wells, and for management of idle wells, are outside the scope of this rulemaking.*

Automatic Termination of Injection

0009-7 Fill gaps in the framework for reducing injection overpressurization incidents by requiring that wells are equipped to automatically terminate injection if the pressure exceeds Maximum Allowable Surface Injection Pressure (MASIP). As currently proposed, there is no requirement that all wells be equipped with devices that automatically terminate injection upon exceedance of MASIP. Nor is there an explicit instruction of what do when an operator detects that surface injection pressure has exceeded MASIP. Both of these gaps can be filled by adopting a device requirement like the one in Ohio.
Response to 0009-7: NOT ACCEPTED. *An auto-shutoff system can cause operational issues; for example, a sudden shut-off may hammer back on the pump system and cause significant damage to equipment. A slow valve-down is a better and safer way to shut down. In addition, auto-shutdown usually requires SCADA or other advanced operating system, which is not available to all operators.*

Environmental Impacts

Comment 0013-1 Commenter states belief that the proposed regulations will result in the expansion of oil production via enhanced oil recovery. As a result, they state the Division's proposed regulations "run contrary to the need to phase out fossil fuel production to address climate change" because they do not stop oil production. Points out that Climate change is a very serious threat and the production of use of fossil fuels continues to exacerbate this threat. The commenter further argues that the assumed expansion of oil drilling will increase carbon emissions and threaten biological resources.
Comment 0013-2 Commenter analyzes PRC 3106 and indicates that the duty to prevent harm supersedes the wise development of oil and gas such that DOGGR cannot encourage development of oil and gas if it is possible to prevent damage to life, health, property and natural resources by taking alternative actions. The proposed regulations cannot be reconciled with the duty to prevent harm under subdivision (a). Additionally, Article X of the California Constitution requires water resources to be put to "beneficial use to the fullest extent of which they are capable. The use of groundwater aquifers to dispose of oil field wastewater is a wasteful, unreasonable use of water. The State has a duty to prevent this destructive use of our aquifers, and to recalibrate and rebalance the groundwater system in light of recent and likely future droughts and other threats posed by climate change. Furthermore, a California Appellate Court recently affirmed that the public trust doctrine applies to the state's groundwater resources. The proposed regulations violate the public trust doctrine by failing to ensure that groundwater is adequately protected for the public. Control Board states in Resolution 68-16 that waters of the state must be protected "to promote the peace, health, safety, and welfare of the state." Water injection may not create pollution or a nuisance and must be "consistent with the maximum benefit of to the people of the state…." DOGGR must adhere to these legal protections by prohibiting injection activity that would create pollution or a nuisance.
Response to Comments 0013-1 and 0013-2: NOT ACCEPTED. *PRC section 3106, subdivision (b), directs the Division to "supervise the drilling, operation, maintenance, and abandonment of wells so as to permit the owners or operators of the wells to utilize all methods and practices known to the oil industry for the purpose of increasing the ultimate recovery of underground hydrocarbons…." At the same time, the Division has a broad mandate to protect life, health, property, and natural resources. Properly interpreted, the legislative direction of PRC section 3106 contemplates that, where a practice can be permitted with manageable risk, it may be permitted. The proposed regulations are consistent with this legislative direction.* *The Division disagrees with the commenter's assertions that the proposed regulations are somehow in conflict with Article X of the California Constitution, the public trust doctrine, and SWRCB Resolution 68-16. In its capacity as a regulator of underground injection projects, the Division does consider, and will continue to consider, applicable state laws and policies. Additional to the Division's regulatory oversight, the SWRCB and the regional water boards also exercise their own independent regulatory authorities applicable to underground injection projects. To facilitate efficient and effective administration of applicable law and policy, the Division coordinates with the SWRCB and the regional water boards in the evaluation and approval of underground injection projects. For the same reasons,*

the Division consulted with the SWRCB and the regional water boards in the development of the proposed regulations. The proposed regulations will improve, not hinder, the Division's ability to achieve its regulatory mission as defined by state law and policy.

0013-12

Regulations require full environmental review pursuant to the California Environmental Quality Act. The regulations do not indicate that DOGGR intends to conduct any sort of environmental review in conjunction with project approval letters.

Response to Comment 0013-12: NOT ACCEPTED. *The Division has determined there is no substantial evidence indicating adoption of these regulations could adversely affect any of the environmental resource areas, as listed in Appendix G of the CEQA Guidelines.*

Injection wells have been an integral part of California's oil and gas operations for nearly 60 years. There are approximately 55,000 oilfield injection wells operating in California. These include enhanced oil recovery 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

Past regulations require considerable case-by-case interpretation to identify appropriate project-specific requirements. Over time, this 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 method sand advancements in the understanding of threats to health, safety, and the environment.

The regulations will implement the Primacy Agreement with the US EPA to ensure its current regulations are sufficient in protecting groundwater resources. These regulations will (1) modernize, clarify, and augment the regulatory standards applicable to underground injection operations associated with oil and gas development in California; (2) ensure that injected fluids are confined to approved injection zones and that wells are not allowed to become a potential conduit for contamination of groundwater or the dilution of hydrocarbon resources; (3) ensure that underground injection operations will not result in surface expressions; and (4) specify a list of circumstances that require operators to notify the Division and cease injection until the Division authorizes resumption.

The provisions in these regulations regarding injection above fracture pressure are an example of how these regulations achieve these goals and address past practice. The existing provisions in Section 1724.10(i) addressing injection above fracture pressure are specific to sustained liquid injection, and injection above fracture pressure is common for cyclic steam injection operations in diatomite formations. The new requirements of Section 1724.10.3 include performance standards and a regulatory framework to address surface expressions and otherwise ensure protection of life, health, property, and natural resources.

These regulatory amendments are designed to protect natural resources and the environment, and overall would enhance protection of life, health, property, and natural resources, and there will be no physical change in the environment resulting from compliance with the amendments.
0013-13 These revisions would substantially change the regulatory requirements that were presented to the U.S. EPA when California applied for primary authority ("primacy") over Class II injection wells. Such substantial changes to groundwater protection in the state would have to be first approved by the EPA before DOGGR could implement these rules. The regulations would not be enforceable until the EPA has formally approved the changes. Given the potential environmental impacts that would occur as a result of these changes, EPA would be required to conduct and complete a full environmental impact study (EIS) prior to approving these.
Response to Comment 0013-13 NOT ACCEPTED. *This comment misconstrues the relationship between the SDWA and the Division's regulatory authority. The US EPA's approval of a program revision is not a prerequisite for adoption of the proposed regulations as California law. The Division's authority to regulate the drilling, operation, maintenance, and plugging and abandonment of oil and gas related injection wells within California resides in state law. (See PRC, §§ 3000 et seq., 3106.) The Informative Digest portion of the Notice of Proposed Rulemaking Action discusses the history of the SDWA and its interplay with state law.* *The Division has communicated with the US EPA about the proposed regulations frequently throughout the development lifetime of the proposed regulations. It is likely that either the Division or the US EPA will initiate a program revision after the completion of this rulemaking action. A primary purpose of such a revision would be to update federal documentation for the Class II portion of the UIC program for California, so that it accounts for recent changes in applicable California law, including the proposed regulations. Procedures for revision of an existing UIC program exist in federal regulations. (See 40 CFR § 145.32.) Additional guidance regarding how the US EPA may interpret and apply these procedures may be found in US EPA UIC Guidance 34, available from the US EPA and on the Division's website.*

<u>Groundwater Protection</u>

0003-1 Commenter calls on the Division to take a fresh look at which groundwater is protected by: 1) Strengthening the aquifer exemption criteria; 2) creating a new class of groundwater that is more protective than the federal USDW based on quantity and salinity, and 3) establishing a system for public notification and dissemination of detailed information of which groundwater is being used as injection zones and/or has been exempted from protection. However, the absence of groundwater monitoring requirements (or an exemption based on the absence of protected water is still concerning. The SWCRCB should either explicitly approve groundwater monitoring plans or exemptions for all injection projects. SB 4, which describes groundwater monitoring requirements for well stimulation treatments, provides a good model for requirements.

Response to Comment 0003-1: NOT ACCEPTED. *Modification of the criteria for aquifer exemption is outside the scope of this rulemaking action. The criteria for aquifer exemption are established in federal law under 40 CFR part 146.4 and expanded upon in state law under PRC section 3131.*

Defining a new regulatory class of groundwater is also outside the scope of this rulemaking action. The proposed regulations continue and clarify the Division's practice of identifying "freshwater" (defined as containing 3,000 mg/L or less TDS) and USDW (as defined by federal law) as categorical thresholds of regulatory significance. (See proposed section 1720.1.) As discussed in the Initial Statement of Reasons, these thresholds harmonize with existing SWRCB policy and federal law. The Division believes these thresholds provide appropriate guideposts for the protection of groundwater resources in most situations. To the extent special circumstances may call for different considerations, the Division possesses broad authority to implement case-by-case requirements as necessary to prevent damage to life, health, property, and natural resources.

Imposing groundwater monitoring requirements on all UIC projects would impose a substantial cost on operators without a corresponding or commensurate public benefit. Rather, the proposed regulations envision requiring groundwater monitoring on projects based on identified risks. In evaluating projects, the Division will consult with the State and Regional Water Boards about potential risks involved and require monitoring as a condition of approval as needed to protect beneficial use waters. Groundwater monitoring for all projects is not necessary in areas where protected groundwater is not present or proximal.

Injection and Fracture Gradient

0003-3, 0013-3
The revised draft continues to allow injection pressure to exceed the fracture gradient. This provision leaves groundwater and surface conditions unprotected.

Response to Comment 0003-3, 0013-3: NOT ACCEPTED. *As discussed in the Initial Statement of Reasons, confinement of injected fluids to the approved injection zone is the core principle by which the Division, and these proposed regulations, evaluate and ensure the safe operation of underground injection projects. Although as a general rule the proposed regulations require a maximum allowable surface injection pressure less than the fracture gradient (see proposed section 1724.10.3, subdivision (a)), the proposed regulations contemplate situational approval for injection pressure above the fracture gradient—provided that such injection can be done consistently with the core principle of fluid confinement, and that it is necessary for hydrocarbon production. Only where the operator can demonstrate to the Division that use of a surface injection pressure above the fracture gradient will not initiate or propagate fractures outside of the approved injection zone would the Division grant approval. As noted in the Initial Statement of Reasons, the primary example for this situation is hydrocarbon-rich diatomaceous formations, for which the facture gradient is so low that injection at any pressure effectively exceeds the facture gradient. Based on the experience and technical expertise of its staff, the Division believes that, when conditioned on the situation-specific factual demonstrations articulated in proposed section 1724.10.3, subdivision (b), surface injection pressures*

above formation fracture gradient may be used safely and appropriately in underground injection projects.
0004-6 Injection pressures must be less than 50% of expected lowest fracture pressures within well paths.
Response to Comment 0004-6: NOT ACCEPTED. *Section 1724.10.3 contemplates that fracture gradient will determined on a well-specific basis, as appropriate to ensure injected fluids remain within the approved injection zone. There is no reason to limit injection pressures to 50% of fracture gradient as a prescriptive, statewide requirement.*

COMMENTS BY SECTION

<u>1720.1 Definitions</u>

0001-1, 0006-1 1720(a): Commenter recommends striking the word "temperature" from the "area of review" (AOR) definition as well as striking the term "area of influence." As a technical matter temperature alone is not an indication of whether fluid may migrate out of the intended injection zone. It should also be noted that incorporation of temperature as a basis for defining as AOR creates an inconsistency with the U.S. Environmental Protection Agency's (USEPA) AOR definition. The term "area of influence" is not defined in the draft regulation. Incorporating the use of the phrase without a definition to go by could create regulatory confusion.
Response to Comment 0001-1, 0006-1: NOT ACCEPTED*. "Temperature" was added to the definition of AOR in recognition of the fact that temperature can change the way that fluids behave. It is not intended to define the AOR on its own, but as a part of the holistic analysis of the area of influence. The area of influence does not require a definition because the term is used with its ordinary meaning. Although this does differ slightly from the USEPA definition, the state is free to impose more stringent regulations as needed to achieve its underlying goal of the protection of life, health, property, and natural resources.*
0003-4 1720.1(a): Commenters appreciate the clarification to ensure the AOR is at least as broad as the area of influence. However, the fixed radius option still lacks clarity. Commenter suggests clarifying that the center of the radius must be defined as the entirety of the wellbore to account for directional or horizontal wells.
Response to Comment 0003-4: NOT ACCEPTED. *The definition provides that the Division will ensure that the AOR is at least as broad as the area of influence. Therefore, the AOR must be at least as broad as the area it may influence, and the one-quarter-mile fixed radius can only be used when it represents or exceeds the area that will be affected by the injected fluid.*
0011-1 1720.1(a): The proposed definition of Area of Review (AoR) still falls far short of best practice, including three recent rulemakings in California: the Division of Oil Gas and Geothermal Resources' (Division) well stimulation and gas storage regulations, and the Air Resources Board's (ARB) proposed carbon capture and sequestration (CCS) protocol under the low carbon fuel standard (LCFS). The

revised proposed definition of AoR specifies that the Division will "ensure that the area of review is at least as broad as the area of influence." The phrase "area of influence" is undefined and only appears once in the proposed rules – in the AoR definition. There is no scientific basis or support for a quarter-mile fixed radius AoR and it should be eliminated as an option. Consistent with California's rulemakings on well stimulation, gas storage, and CCS, the Division should revise its definition of AoR by requiring operators to determine the three-dimensional volume within which injected and displaced fluids will be contained – in other words, the volume currently defined as the "injection zone." The currently proposed definition of area of review should be replaced with the proposed definition of injection zone.
Response to Comment 0011-1: NOT ACCEPTED. *The area of review and the injection zone should not be conflated. The injection zone is a three-dimensional space that encompasses where the injected fluid may actually go, while the area of review is a broader area that encompasses all areas which may be subject to the influence of injected fluid even if the fluid itself never travels outside the zone. The quarter-mile area of review will only be permitted when the operator and the Division are confident that the actual area of review will be smaller than a quarter-mile; in no case will the quarter-mile be used if it does not include all areas subject to influence from the project.*
0004-11 1720.1(a): The area must be defined by feet: 1320 feet not ¼ mile of well head and wellbore which could be 10,000 feet long, not just casings.
Response to Comment 0004-11: NOT ACCEPTED. *Commenter provides no justification for a requirement that the distance be in feet rather than miles. The area of review is specified to be the <u>calculated lateral distance</u> where the fluid may migrate and would include fluid from all parts of the wellbore.*
0004-12 1720.1(a): The Area of Review must include injection and expected production/recovery/withdrawal wells along with intervals between the end point of injection/production wells.
Response to Comment 0004-12: NOT ACCEPTED. *The AOR is calculated for each well and is intended to cover the area that fluids from that well may migrate as a result of project operations. Thus, all wells that are within a calculated AOR for a single well are included in the area of review analysis.*
0004-13 1720.1(b) and (m): Commenter recommends replacing the term "hydrocarbons" with "reservoir fluids and gases" and would focus the purpose of a steamflood injection wells to be an impact on other "producing" wells.
Response to Comment 0004-13: NOT ACCEPTED. *Commenter's changes do not add to or clarify the meaning of the regulatory language. The purpose of these wells is to produce, or enhance the production of, hydrocarbon resources. Although the wells do produce reservoir fluid and gas, this is not the purpose of these wells, which is focused on hydrocarbon production.*
0008-1 1720.1(e): Waters that have been exempted by the Federal EPA no matter the TDS and are not considered "Freshwater". This clarification removes confusion regarding exemption versus confusion regarding TDS level.

Response to Comment 0008-1: NOT ACCEPTED. *Understanding subsurface conditions is important for effective regulation of underground injection projects. The Division sees regulatory value in requiring operators of underground injection projects to provide various cross sections, electric logs, and casing diagrams identifying the location of geologic units containing freshwater. See section 1724.7, subdivisions (a)(2)(E) and (F), and section 1724.7.1, subdivision (a). The potential that a geologic unit could simultaneously contain "freshwater" as defined in the proposed regulations and also be designated exempt from classification as a USDW by the US EPA does not present a conflict.*
0003-5 1720.1(g): The lack of confining requirement in the injection zone continues to be an issue that leaves groundwater vulnerable. In order to ensure that injected fluids do not migrate out of the injection zone, this definition must be strengthened. "Anticipated to occupy or otherwise be located" is vague and could be abused. "Injection zone" means the defined three-dimensional space with fixed boundaries that can be demonstrated to be geologically confined by impermeable layer(s), where fluid injected by an underground injection project is anticipated to occupy or otherwise be located. The injection zone may include more than one formation or strata. The injection zone must be geologically separated from any groundwater that may have beneficial uses.
Response to Comment 0003-5: NOT ACCEPTED. *The definition of an injection zone is focused on defining that area of space which is expected to be occupied by injected fluid. This may include areas that are confined by impermeable layers or may include a smaller or larger zone that is calculated to be part of the area of influence for well fluids. The presence of an impermeable layer is not a requirement for the injection zone provided that it can be demonstrated that fluid will not migrate outside of the identified zone.*
0013-5 1720.1(h): The proposed regulations create a new category of "low-energy seeps." Injected fluid and naturally occurring fluids can both contaminate cleaner sources of drinking water. Whether the seeping fluid is injected fluid or naturally occurring substances that oil activities have caused to seep, there is a risk of contaminants flowing into surface or groundwater. DOGGR has provided no basis for its decision to treat these types of seeps differently.
Response to Comment 0013-5: NOT ACCEPTED. *A "low-energy seep" is a surface expression where the operator has demonstrated that the fluid coming to the surface is low-energy and low-temperature, is not injected fluid, and is contained and monitored in a manner that prevents damage to life, health, property, and natural resources. If the operator fails to demonstrate to the Division that the seep is contained and monitored in a manner that prevents damage to life, health, property, and natural resources, that seep will be a surface expression and in violation of Section 1724.11(a).*
0004-14 1720.1(j): As used in the Well Construction regulations, mechanical integrity must include cements and well designs, constructions and operations.
Response to Comment 0004-14: NOT ACCEPTED. *Well construction standards are not a subject of these regulations. The Division is conducting pre-rulemaking activities for new well construction regulations. Commenter can find out more here: https://www.conservation.ca.gov/dog/Pages/Well-Construction.aspx. In the meantime, current well construction standards can be found in the California Code of Regulations sections 1722.2 through 1722.4.*

0004-15 1720.1(j): Define “reliably”; if you use define or delete.
Response to Comment 0004-15: NOT ACCEPTED. *The word “reliably” is used consistent with its ordinary meaning; additional definition is not needed.*
0001-2, 0006-2 1720.1(h)(2): Commenter supports DOGGR establishing a formal definition of “low energy seep.” For purposes of finalizing the definition however, we recommend deleting (2) relative to injected fluid. As DOGGR is aware operators increasingly use treated produced water for enhanced oil recovery operation in order to decrease reliance of on otherwise usable water sources. Accordingly, it will be difficult to properly characterize whether previously injected produced water is comingled with native in situ fluids in a low energy and low temperature surface expression.
Response to Comment 0001-2, 0006-2: NOT ACCEPTED. *Where injected fluid is present at the surface, it does not meet the definition of a low-energy seep; it is a surface expression. Low-energy seeps are naturally occurring seeps that do not flow injected fluid. The intent of the definition is to distinguish between natural seeps not directly associated with injection from those surface expressions that need to be mitigated. The flow rate and energy of the seep will assist in determining whether injected fluids are present; produced water is only likely to flow in a high-energy surface expression.*
0006-3, 0012-12 1720.1(i): Commenter supports the addition of this new definition. However, based on available data, we believe 15,000 bbls per year is more representative of a “low use” cyclic steam injection well. As proposed, a significant percentage of some of the association’s members’ wells would not qualify as “low use” wells even though they are operated for fewer than 24 days of injection in a calendar year. The industry considers wells to be “low use” if they are used for less than 24 days (for injection) and have injection volumes that do not exceed 15,000 bbls/year.
0007-1 1720.1(i): This definition [low-use cyclic steam injection well] will favor certain field in Kern County and limit others. By definition, a cyclic steam well periodically injects steam and should be subject to different rules than wells injecting 24/7. For this definition to work in shallower fields, Commenter suggests 30,000 barrels of steam on average per year. We do not believe the volume of steam is linked to the integrity of the well (number of cycles would be a more suitable measure). We also recommend using a rolling average of 5 years rather than limited the definition to only apply to wells that did not exceed the amount on an annual basis for the past 5 years.
0010-1 1720.1(i): Commenter believes that the limited number of days and low volume of steam excludes wells that are cycled infrequently and may have larger volume cycles. Commenter would propose that low use cyclic steam injection wells have days of injection in a calendar year of 30 day, and a volume of 60,000 barrels of injection.
0014-14 1720.1(i): Commenter recommends 45 days of injection and 30,000 barrels of injection in a calendar year as a better representation of a low use well in California based on feedback from members and real-world field conditions.

0015-2 1720.1(i): As an operator of thousands of cyclic steam wells, Commenter's practice has been to consider wells that undergo two or fewer steam cycles per year as low-use injectors. For example, our typical single injection interval is 11 days at an injection rate of approximately 1,000 barrels of steam. Amending the definition to 40 days and 30,000 barrels would ensure that wells undergoing two or fewer cycles would be so defined.
Response to Comments 0006-3, 0007-1, 0012-12, 0010-1, 0014-14 and 0015-2: NOT ACCEPTED. *The thresholds for low-use wells were developed after analysis of the data provided by operators in their monthly injection reports over the past five years. The Division is confident they represent the target set of wells that are low use as compared to other injection wells. In response to comment 007-1, requiring that these thresholds are met for the past five calendar years provides a bright-line standard and ensures that these wells are low use.*
0003-6 1720.1(m): An additional well type should be added to the list in this definition: "thermal recovery". Commenters are still concerned that, in many cases, the regulations lack specific requirements for different types of injection projects, whether recovery methods or disposal. Each type of enhanced oil recovery and disposal have specific risks and operational differences that may necessitate unique requirements. The proposed regulations do not adequately account for these differences. For example, we recommend that these regulations specify that CO2-EOR operations must obtain a permit under a regulatory scheme specifically designed to handle the injection of CO2, such as the Air Resources Board's proposed carbon capture and storage protocols under the Low Carbon Fuel Standard, the UIC Class VI program, or another regulatory program designed specifically for CO2-EOR. These regulations should specify that Class II regulations alone may not be applied to such a CO2-EOR project.
Response to Comment 0003-6: NOT ACCEPTED. *The defined term "underground injection project," at section 1720.1, subdivision (p), describes the range of injection operations subject to the proposed regulations. This definition includes a non-exhaustive list of project types as illustrative examples. In the First Revised Text of Proposed Regulations, the Division added to the list of examples "carbon dioxide enhanced oil recovery." The Division added this example to clarify that this type of injection operation is an underground injection project within the scope of the proposed regulations. The Division does not believe the addition of "thermal recovery" to list of examples in this definition would improve clarity. The Division does not see a need to include within the proposed regulations an index of cross references to potentially applicable permitting requirements overseen by other local, state, and federal entities, as the commenter suggests.*
0003-7 1720.1(n): Commenter recommends adding a definition for a class of protected water which establishes that all waters with potential beneficial uses be protected from injection activity. This class of groundwater must include: aquifers that could supply a private water well, or any other beneficial use, regardless of meeting the federal USDW definition, including the quantity threshold; aquifers with salinity greater than 10,000 TDS mg/L in order to protect aquifers that may be used in conjunction with desalination. While there may not be a scientifically justifiable upper salinity limit, a salinity level that at least protects groundwater currently in use via desalination would be more

appropriate than 10,000 TDS mg/L, which is an arbitrary value and not based on actual water use; aquifers that currently supply water for any beneficial use. This would ensure that all water users, including private well owners are protected.
Response to Comment 0003-7: NOT ACCEPTED. *The regulations protect "freshwater" as defined, as well as USDWs. Creating an additional class of protected water and changing the criteria for exemption is beyond the scope of the proposed regulations.*
0004-16 1720.1(n): Surface expression herein must also include the physical movements (uplift or downdrop) of the ground surface due to injection or production, respectively, as experienced and documents in the Inglewood and Wilmington Oil Fields. Movement…any without limits: E.g., 0.1in over >10,000 sq. ft) and for "subsidence mitigation"
Response to Comment 0004-16: NOT ACCEPTED. *Subsidence monitoring is only required under these proposed regulations for projects known to cause surface expressions. Subsidence monitoring statewide is covered by Public Resources Code sections 3315 through 3347.*
0004-17 1720.1(p): "Totally inadequate definition of UIC, which must include production of displaced hydrocarbon fluids as eluded to elsewhere in UIC texts. "Control zone" is ok if consistently used. This section contains mention of gas storage facilities which commonly use water control for accelerated withdrawal (with fluid injection) and injection of gas (with fluid withdrawal)."
Response to Comment 0004-17: NOT ACCEPTED. *It is unclear why commenter changed "underground injection project" to "underground control project" as that term does not appear anywhere in the regulations. Instead, the definition is intended to refer to those groups of wells that operate together as a "project" and to include the types of wells which might make up such a group. Commenter has replaced "injection zone" with "control zone" which is not accurate, because it is not a zone of control but a zone where fluids are intended to migrate due to injection pressures. Gas storage facilities are specifically excluded from these regulations; the focused and comprehensive gas storage regulations that became effective on October 1, 2018 cover these operations fully.*
0008-2 1720.1(s): Commenter remains concerned with the classification definition of a "Water Supply Well" and the continued operation of the wells that supply the Mount Poso Power Plan (Bioenergy facility). A DOGGR classified Water Supply Well and/or water from the West Mount Poso oil processing plant provide the Mount Poso Power Plant water that is converted to steam and used to produce electricity. The DOGGR classified supply wells in the West Mount Poso project provide water from the USDW exempted Vedder formation. This section must ensure the continued water supply wells operation as a beneficial use for the power plant.
Response to Comment 0008-2: NOT ACCEPTED. *This definition does not affect the operation of water supply wells and is provided to clarify data requirements elsewhere in the regulations.*
0004-18 1720.1(t): Replace "liquid" with "fluids" and "other producing wells" with "producing wells".
Response to Comment 0004-18: ACCEPTED IN PART. *The definition of "waterflood injection well" now reads "producing wells" instead of "other producing wells." "Liquid" encompasses the water or water-based injection relevant to this definition.*

0009-11 Define “gas disposal well” as used in 1724.10.1 and 1724.10.2. This term is used to adjust timelines on MIT Part I and Part II, but commenters have not found a definition either in this proposed rule or elsewhere in California Statutes and Regulations for the Division of Oil, Gas and Geothermal resources.
Response to Comment 0009-11: NOT ACCEPTED. *A definition for “disposal injection well” appears in section 1720.1(c). A “gas disposal well” would be a well that meets the definition of a disposal well and that injects gas as the fluid that is being disposed. A more specific definition for a “gas disposal well” is not needed.*
0004-21 “Pertinent”, “proper” and “evaluation” must be defined or referred to section.
Response to Comment 0004-21: NOT ACCEPTED. *These words are used consistent with their ordinary meaning; additional definition is not needed.*
0004-19 1724.6(a), 1724.6(d), 1724.10.1(c)(2)(E), 1724.10.2(g): “Shall/must/will” must have consistent definitions and usage; federal usage would support removal of “shall” and replacement with “must.”
Response to Comment 0004-19: NOT ACCEPTED. *In this context, “shall,” “must,” and “will” are synonyms that both indicate a specific requirement that has to be fulfilled. These terms are contrasted with “may” which indicates an action which could be taken but does not have to be. These terms are used consistent with their ordinary meanings and do not require additional definition to be understood in context.*
0004-43 1724.7(d), 1724.7.1(a): Define “appropriate”. Section must also state concerns and prohibition of knowingly submitting by the owner, operator, or contractor(s) of erroneous information or data for consideration by the Division and must reference appropriate penalty section and ground for recession of the appropriate permit or approval.
Response to Comment 0004-43: NOT ACCEPTED. *The term “appropriate” is used consistent with its ordinary meaning, “suitable or proper in the circumstances”. Thus, the licensed professional must ensure that their approval of the data is suitable given their licensee requirements under the Business and Professions Code. Where erroneous data is submitted, the Division has the option of imposing civil penalties pursuant to PRC 3236.5.*
0004-20 1724.6(a), 1724.7: Division or district deputy must have consistent definitions and usage, as the District Deputy (formal title) is included under Division, delete all use of District Deputy.
Response to Comment 0004-20: NOT ACCEPTED. *Where a requirement may be approved by any person authorized to approve operator requests, the Division generally uses just “the Division.” Where necessary the Division Deputy is specified as the person who must approve a request. The Division will continue to use both terms where appropriate; they do not need definitions as they are titles.*

1724.5 Purpose, Scope, and Applicability

0013-7 1724.5: Citations Appear to Be Erroneous. Article 5 does not contain sections 1726 through 1726.10." DOGGR should clarify exactly what provisions it is referring to.
Response to Comment 0013-7: ***NOT ACCEPTED.*** *As a part of this package, Articles 4 and 5 are being renamed. Article 4 will now be Underground Injection Control, and Article 5 will be Requirements for Underground Gas Storage. Thus, the reference in these proposed regulations is correct as written.*

1724.6 Approval of Underground Injection Projects

0003-8 The regulations do not provide the public any opportunity to weigh in on the issuance of project approval letters (PALs). We continue to call for a 30-day public comment period and public hearing prior to the issuance of any PAL.
Response to Comment 0003-8: NOT ACCEPTED. *Consistent with the Division's April 1981 "Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act," and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. The Division does not see a need to codify this policy within the proposed regulations. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency.*
0005-1 1724.6(a): The Division consultation with the State Water Resources Control Boards or Regional Water Quality Control Board does not have a defined process or timeline, leading to an open-ended review process and is vague as currently written. SoCalGas recommends the Division provide a more complete description of the review process, what aspects the State Water Resources Control Boards or Regional Water Quality Control Board would weigh in on, and any applicable timeframes.
Response to Comment 0005-1: ACCEPTED IN PART. *Committing to regulation a set of predetermined timelines for the Division to complete review and approval of underground injection projects is not within the contemplated scope of the proposed regulations. Evaluation of injection wells and subsurface features is a complex endeavor, with many case-by-case variables to consider. The Division undertakes approval and review of underground injection projects with diligence, but variations in the time necessary to evaluate each project are inherent to the nature of the exercise. It is Division practice to maintain close contact with operators regarding the status of pending reviews and approvals affecting their existing or proposed underground injection projects.*
0008-3 1724.6(c): To avoid confusion regarding the current PAL requirement Commenter supports issuing a revised/updated PAL to avoid potential confusion regarding current or addendum PAL requirements.

Response to Comment 0008-3: NOT ACCEPTED. *The reference in proposed section 1724.6, subdivision (c), to the use of an addendum to modify a project approval letter reflects the reality that in some situations it may be more practical to update a portion of a project approval letter rather than to issue a new project approval letter. For example, this might be the case when tracking changes in which specific injection wells within an underground injection project are approved for injection at any given time, or in documenting changes to a required monitoring program.*
0003-11 1724.6(d): Project review should occur every year.
Response to Comment 0003-11: NOT ACCEPTED. *Completing a review of an underground injection project often takes between three and six months, sometimes longer. Given the variations of size and complexity that exist among underground injection projects, the number of underground injection projects in the state, and practical realities of staff resource limitations, the Division believes that "periodically, but not less than once every three years" is an appropriate regulatory benchmark for routine Division review. This benchmark provides flexibility for the Division to prioritize its resources; it contemplates reviewing some projects sooner or more frequently than others as circumstances warrant, while still providing a clear expectation of review by no later than a regular schedule.*
0003-12, 0011-2 1724.6(g): This section was removed since the previous draft. We oppose the removal of this section. There must be an expiration period for injection projects that are not utilized.
0013-8 1724.6(g): Unused permits should contain an expiration date. The deletion of this subsection gives rise to the potential for the issuance of a permit of indefinite duration, even where an operator has not engaged in any injection activity for years. DOGGR should only issue permits that expire upon a date certain."
Response to Comments 0003-12, 0011-2, and 0013-8: NOT ACCEPTED. *The proposed regulations no longer prescribe as a predetermined regulatory consequence the expiration of a PAL after 24 months without injection, requiring the operator to then obtain a new PAL in order to resume injection. Instead, the proposed regulations now address project-level inactivity with several functionally similar but more flexible provisions focused on well-specific considerations. Proposed section 1724.6, subdivision (b), has been amended to indicate that the Division may specify within a PAL a limited approval duration for an underground injection project. Additionally, under proposed section 1724.13, subdivisions (a)(8) and (b), unless the operator has requested and received Division approval for the well to remain approved for injection while idle, an operator is required to cease injection into an injection well when it becomes idle, and not resume injection without subsequent written permission from the Division. Proposed section 1724.6, subdivisions (d) and (e), make clear that obtaining permission from the Division to resume injection that has been suspended pursuant to proposed section 1724.13 may involve review and revision of PAL terms and conditions.*

1724.7 Project Data Requirements

0004-8 UIC geologic units must be quantitatively modelled for physical and operational parameters.
Response to Comment 0004-8: NOT ACCEPTED. *The Division believes the project data requirements as proposed will provide adequate information for the evaluation of underground injection projects in most circumstances. If a need arises, the Division has authority to require additional or different data on a case-by-case basis. Proposed section 1724.7, subdivision (a)(6), explicitly contemplates such project-specific flexibility by requiring operators to provide "any other data that, in the judgment of the Division, are pertinent and necessary for the proper evaluation of the underground injection project."*
0011-3 1724.7: Commenter renews its previous request that groundwater monitoring be mandatory for all UIC Projects, consistent with the Division's rules for well stimulation operations.
Response to Comment 0011-3: NOT ACCEPTED. *Evaluation of whether groundwater monitoring is necessary for any given underground injection project involves coordinated input from the Division, the SWRCB, and the appropriate regional water quality control board. Where necessary to ensure appropriate protection of groundwater resources, the proposed regulations contemplate that groundwater monitoring will be required as part of the supporting project data to be filed with the Division. See proposed section 1724.7, subdivision (a)(3)(E). Conversely, if an underground injection project is situated in a location where groundwater resources are not proximal, groundwater monitoring may be unnecessary. The proposed regulations preserve and support the ability of these agencies to exercise independent but coordinated authority in tailoring monitoring requirements to meet situation-specific considerations. The Division does not agree that adding a more prescriptive groundwater monitoring requirement to the proposed regulations would be an improvement.*
0009-13 1724.7: In the absence of a more comprehensive emergency response planning section, DOGGR should cross-reference to spill control planning required elsewhere, and add a requirement that operator employees and contractors be trained and drilled in implementing 1724.13.
Response to Comment 0009-13: NOT ACCEPTED. *A cross-reference for the spill contingency plan is not needed within section 1724.7, regarding project data requirements. Existing regulations already require operators to develop and file with the Division spill contingency plans. (See sections 1722, subdivision (b), 1722.9, and 1743.) Section 1724.12 does cross-reference to the spill contingency plan requirements presented in existing section 1722.9, but only for the clarification that surface expression containment measures are among the elements to be included in a spill contingency plan.*
0004-23 1724.7(a): "Approved injection zone" or "approved Area of Reference" – requires definitions, references, and consistent use.
Response to Comment 0004-23: NOT ACCEPTED. *A definition for "injection zone" and "area of review" appear in the definitions section 1720.1. They are used throughout the document consistent with their definitions as outlined by that section.*

0004-25 1724.7(a): Define “current” and “accurately” and “REFLECTIVE” and use consistently throughout the section.
Response to Comment 0004-25: NOT ACCEPTED. *These words are used consistent with their ordinary meaning; additional definition is not needed.*
0004-26 1724.7(a)(1)(B)(iii): As gas storage is NOT production all gas injection, storage, and withdrawal/production – Montebello and Aliso and others must be considered herein.
Response to Comment 0004-26: NOT ACCEPTED. *From a regulatory perspective, underground gas storage projects exhibit numerous meaningful distinctions from underground injection projects. The Division has already developed an existing set of different regulations to address the specific considerations applicable to underground gas storage projects, at sections 1726 through 1726.10.*
0004-27 1724.7(a)(1)(B)(iii): If information is NOT KNOWN to the operator and submitted to the Division, the AOR may be inadequate or incomplete, and application must NOT be approved.
Response to Comment 0004-27: NOT ACCEPTED. *The project data requirements presented in section 1724.7 all contribute to a clearly articulated performance standard for project approval: an underground injection project will not be approved unless it is supported by data that demonstrates to the Division’s satisfaction that fluid will be confined to the approved injection zone and will not cause damage to life, health, property, or natural resources. See section 1724.7, subdivision (a).*
0004-28 1724.7(a)(1)(C): Commenter recommends specifying that this requirement applies to all the wells within the AOR and that they include wellbore paths, casings, liners, cementing, screens, and plugging.
0004-30b 1724.7(a)(1)(C)(iii): “All” includes producing wells within the AOR. The AOR must include the related producing wells involved in the EOR using the “project” injection wells. Similarly, all gas storage wells and zones must be included where the injection project operates in conjunction with gas injection/withdrawal using fluid drives.
Response to Comments 0004-28 and 0004-30b: NOT ACCEPTED. *The language of this section points to subdivision (a)(1)(B)(i) that requires a listing of all wells within and adjacent to the area of review. The rest of the information that commenter would require is included in 1724.7.1 as part of the casing diagrams, which must be submitted for those same wells.*
0004-30a 1724.7(a)(1)(C)(iii): Commenter would also change the language to require both a graphical casing diagram and a flat file data set.
Response to Comment 0004-30a: NOT ACCEPTED. *The proposed regulations allow operators the option to submit casing diagrams either as a graphical documents or flat file data sets. Compared to fixed graphical diagrams, flat file data sets are often a more convenient vehicle for containing and flexibly accessing a large amount of information, but either option could adequately satisfy the informational objective of the regulation.*

0004-31 1726.7(a)(1)(D): Commenter indicates that there is a confused/confusing use of unit, vs zone, vs formation, vs member and the Division should provide consistent terms and usage throughout the document. Boundaries should be provided for all wells – all production wells and formations, zones, reservoirs, pools, and or units. Producing/injection zones should also be provided.
Response to Comment 0004-31: NOT ACCEPTED. *The terms referenced by the commenter are technical terms of art, but they are familiar terms to regulated community. The Division believes its use of these terms throughout the proposed regulations is necessary for precision and consistent with the prevailing understanding of the regulated community.*
0004-32 1724.7(a)(2): A "geologic study" should require a geological map and three sections with formation/member names then imposed on an oil and gas map.
Response to Comment 0004-32: NOT ACCEPTED. *This section requires a structural contour map, an isopach map, and at least two geologic cross sections through at least three wells. It also requires a representative electric log identifying all geologic units, formations, USDWs, freshwater aquifers, and oil or gas zones. The Division is satisfied that this will provide the needed information to evaluate the geologic realities of a project.*
0004-34 1724.7(a)(2): Define and illustrate zones, areas, units, rocks, mechanism, fault/fractures, traps.
Response to Comment 0004-34: NOT ACCEPTED. *These terms are used consistent with their ordinary meaning; additional definition is not needed here.*
0004-33 1724.7(a)(2)(A): Reservoir clearly involves production zones (unit, formation, etc.) and must include all wells, including production and idle, etc. wells.
Response to Comment 0004-33: NOT ACCEPTED. *This section is focused on the characteristics of the reservoir as it would be affected by injection wells; the injection zone must encompass any area of the reservoir where injected fluids may migrate. Production and idle wells affected by an injection well would be included in the area of review and evaluated for mechanical integrity and fluid confinement, but production zones are not a subject of this regulation.*
0004-29 1724.7(a)(2)(B): Commenter would add "temperature" and "pressure" to the required fluid data and would include liquid "and gas" quality analysis. Inconsistent use of fluids and liquids without reference to gases.
Response to Comment 0004-29: NOT ACCEPTED. *"Fluid" has been defined within these regulations to mean any material or substance which flows or moves, whether semisolid, liquid, gas, or steam. See section 1720.1, subdivision (d). As defined, liquid is the appropriate term when referring to reservoir and injection fluid. As discussed in the Initial Statement of Reasons, if an underground injection project involves injection of gas, then requisite chemical analysis would be determined by the Division on a project-specific basis. Temperature and pressure are not appropriate data point because this is not an analysis of the fluid in place, but analysis of a sample that will travel to a lab; temperature and pressure of the sample at collection are not relevant to the contemplated analysis.*

0004-35 1724.7(a)(2)(B): Reservoir fluid data must include pressures and temperatures and gradients along entire bore of all wells in AOR.
Response to Comment 0004-35: NOT ACCEPTED. *The requirement to measure pressure, temperature, and gradient across the entire bore of all wells in the AOR is excessively burdensome without regulatory benefit. The data requirements as outlined in this proposed section are sufficient to analyze the reservoir fluid for the purposes of these regulations.*
0004-36 1724.7(a)(2)(C): Structural contour map must include faults with >5 ft movement and must include historic earthquake records for AOR and 5 mi radius and assignment of most probably fault planes.
Response to Comment 0004-36: NOT ACCEPTED. *The requirement in subdivision (a)(2)(C) is for all faults; fault size does not need to be specified as there is no desire to artificially restrict the set of faults included. The Division has no need for historic earthquake records and a five-mile radius would be an excessively burdensome requirement without commensurate regulatory benefit.*
0004-37 1724.7(a)(2)(D): The isopach map also include production zones in the area of review.
Response to Comment 0004-37: NOT ACCEPTED. *These regulations are focused on underground injection control and regulation of injection wells. Within the UIC context, the Division does not have a need for an isopach map that includes production zones. Instead, the focus is on making sure that injected fluid does not migrate out of the injection zone.*
0004-38 1724.7(a)(2)(E): Provide Fence Diagram in the area of review through <u>all</u> project wells (three geologic cross sections) including producing zone wells.
Response to Comment 0004-38: NOT ACCEPTED. *The requirement in this section is for a geologic cross section that will be representative of the project so that area geology can be considered. A cross section through all project wells would be excessively burdensome without commensurate regulatory benefit.*
0004-39 1724.7(a)(2)(F): Commenter would modify this requirement to include all electric, temperature and pressure logs below the deepest injection and producing zones rather than the deepest injection OR producing zone.
Response to Comment 0004-39: NOT ACCEPTED. *Commenter's suggested revision to the regulation would, in most cases, result in duplicative information or information of less regulatory value to the Division. If the Division requires additional, situation-specific information to evaluate an underground injection project, section 1724.7, subdivision (a)(6), clearly requires operators to provide that additional information when directed to do so by the Division.*
0004-40 1724.7(a)(3): The injection plan requirement should be changed to an injection <u>and production</u> plan.
Response to Comment 0004-40: NOT ACCEPTED. *These regulations are focused on underground injection projects, not production. A "production plan" requirement does not fit within the contemplated scope of this rulemaking action.*

0003-13 1724.7(a)(3)(D): Commenter recommends that operators identify water source wells outside the boundaries of the injection project. Simply identifying wells within the boundaries, is not protective of all wells in close proximity to the project. A one-mile buffer zone is a reasonable distance and would account for migration of fluids outside the injection zone.
0004-41 1724.7(a)(3)(D): All wells should include production wells and formations, zones, reservoirs, pools, and/or units. Presumably the underground injection project includes all within the approved AOR, but this is not stated, including abandoned, idle, gas storage, production passing through the zone(s).
Response to Comments 0004-41 and 0003-13: NOT ACCEPTED. *The purpose of proposed section 1724.7, subdivision (a)(3)(D), is to establish a requirement that the injection plan project data component supporting an underground injection project identify the wells that will be operated as part of the project. The injection plan is not intended to provide an identification of wells that are not operated as part of the underground injection project. Identification of all nearby wells is required as part of the engineering study project data component, under proposed section 1724.7, subdivision (a)(1).*
0004-42 1724.7(a)(3)(D): Define "affected" and compare with "unaffected" which must be included in "other wells" which requirement definitions.
Response to Comment 0004-42: *The word "affected" as used in this subdivision has its ordinary dictionary meaning, "influenced or touched by an external factor." The term "unaffected" is not used and does not need to be defined. "Other wells" in this subsection is a catchall term designed to ensure that all wells used in an underground injection project are included in the injection plan, regardless of how they are classified.*
0003-14 1724.7(a)(5): The regulations continue to leave potential groundwater users vulnerable. The Division should require that operators communicate injection activities to relevant parties. In addition to offset operators, potential water well drillers, such as property owners, should be notified if injection activity could be impacting an underlying aquifer. It is our understanding that Division staff is aware of agricultural wells that have been drilled and use groundwater that is also an injection zone. While the Division may lack the authority to intervene on the permitting or drilling of water wells, through these regulations, additional communication could be required in order to minimize the risk of this situation arising.
Response to Comment 0003-14: NOT ACCEPTED. *Consistent with the Division's April 1981 "Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act," and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency. Extensive information about existing wells, including a graphical*

mapping function and well-specific injection and production data, are available on the Division's website.
0003-15 1724.7(b): Commenter recommends that a new PAL be required to add or modify which injection wells are part of an injection project. The proposed process for the summary list scenario described in the current draft is unclear and needs more specificity, including how changes to that list are requested by operators and the Division's approval process for changes. Since adding injection wells to an underground injection project changes the nature of that project, a new or updated PAL must be required.
Response to Comment 0003-15: ACCEPTED IN PART. *Adding an injection well to an existing underground injection project may or may not have a substantial effect on the overall operation of the project. The Division believes the identification of the well on a list referenced in the PAL and included in the project file is an appropriate baseline requirement. When necessary, the Division will require more substantive revision of a PAL, or an addendum to a PAL—whether as a result of the addition of new injection wells or other considerations.*
0003-16 1724.7(c): All data submitted under this section should be posted online by the Division with five days. There must be a timeframe for posting data to ensure transparency.
Response to Comment 0003-16: NOT ACCEPTED. *The Division cannot commit to a specified timeframe for posting of data because the data must be fully processed and validated. The posting of incorrect or "bad" data would lead to more confusion on the part of operators and the public; data must be fully vetted before posting.*
0004-44 1724.7(d): All professionals must state that they have verified all information and that any analyses have been based on their verification of information.
Response to Comment 0004-44: NOT ACCEPTED. *The signature and stamp of the licensed processionals, as described in the text of this section, will serve the purpose commenter suggests.*
0003-17 17224.7(e): The Division should only accept alternative data to what is required under this section if that option is explicitly granted in writing, in advance.
Response to Comment 0003-17: NOT ACCEPTED. *The Division believes it can determine the appropriate documentation for an alternative data demonstration accepted under proposed section 1724.7, subdivision (e), without committing itself to the prescriptive business process suggested by the commenter.*

1724.7.1 Casing Diagrams

0006-4, 0008-4, 0014-12 1724.7.1(a): Commenter recommends that the regulations clearly indicate that only information which is available needs to be provided. All of the specified information may not be available for older wellbores.

Response to Comments 0006-4, 0008-4, and 0014-12: NOT ACCEPTED. *Proposed section 1724.7.1 describes the default regulatory requirements for casing diagrams. If casing diagrams or other project data required by proposed section 1724.7, subdivision (a), cannot be obtained, proposed section 1724.7, subdivision (e), provides a procedure by which an operator may seek Division approval for an alternative data demonstration.*

0006-5, 0014-11

1724.7.1(b)(2): Typically, available data has already been submitted to the Division through well histories. Commenter does not believe that operators should be required to resubmit data that has already been provided to the Division. This should hold true for future well histories as well. Commenter requests this section be clarified so that additional details need be provided as available and only upon request, with the expectation that the Division will confirm the availability of data against records already submitted before making these requests.

Response to Comments 0006-5 and 0014-11: NOT ACCEPTED. *The data proposed section 1724.7.1, subdivision (b)(2), requires operators to collect and file with the Division are necessary to ensure that there exists in every instance an adequate, standardized body of information by which the Division can evaluate for regulatory compliance the operation of all underground injection projects. In some cases, perhaps many, operators may be able to use existing data sources to achieve compliance with proposed section 1724.731, subdivision (b)(2). To facilitate timely and efficient execution of the Division's regulatory mission, however, it is essential that a complete set of the required data be filed in association with its respective underground injection project. The Division believes concerns regarding any potentially unnecessary duplication in filing for a specific underground injection project are appropriately addressed on a case-by-case basis.*

0001-3, 0006-6

1724.7.1(d): Commenter recommends that (d) be removed as the wellbore survey referenced in 1724.7.1(b)(3) will provide DOGGR the information necessary to calculate the true vertical depth (TVD) if necessary in all wells that are not vertical. In Commenter's technical view the requirement to include TVD in the casing diagram submittal is redundant and subject to interpretation. It is best the Division has the raw un-interpreted data.

Response to Comments 0001-3 and 0006-6: NOT ACCEPTED. *True vertical depth data provides useful information to Division and has direct application in the calculation of maximum allowable surface injection pressure. The Division believes requiring true vertical depth data for all depths listed under proposed section 1724.7.1, subdivision (a), is an appropriate default. If an operator believes providing these casing diagram data presents an unreasonable burden, proposed section 1724.7, subdivision (e), provides a procedure by which an operator may seek Division approval for an alternative data demonstration.*

1724.7.2 Liquid Analysis

0003-2

The Division must expand the list of chemicals required for testing in the fluid analysis section. We recommend the Monitoring and Reporting program from Central Valley Regional Water Control

Board's General Orders for oilfield discharges to land as a model for chemical testing of injected fluids.
0003-18 1724.7.2(a) and (f): In addition to the constituents listed in the current draft, the regulations must also require testing of commonly found chemicals in produced water. We recommend including all chemicals listed in the Central Valley Regional Water Quality Control Board's General Orders for oil field discharges to land. For example, the Monitoring and Reporting Program for the General Orders include several effluent testing requirements that are absent from these regulations, including a total volatile organic compound scan, and testing for radionuclides, along with many others. Additionally, the Regional Board requires quarterly disclosure and testing of all chemical additives in produced water that is discharged under the General Orders. In order to meet the chemical transparency that the public expects for oil and gas operations, the Division must adopt a chemical testing list that includes all of the requirements under the General Orders.
0011-4 1724.7.2: Commenter renews the objection to the significantly narrowed list of analytes that must be tested for routinely and requests that the Division restore the original list of analytes and that benzene, toluene, ethyl benzene, and xylenes be added to the list of analytes, and that fluid to be injected into Class IID disposal wells be tested to determine if the waste is a hazardous waste.
Response to Comment 0003-2, 0003-18, 00011-4: NOT ACCEPTED. *Proposed section 1724.7.2, subdivision (a), requires that liquid analysis include testing for total petroleum hydrocarbons as crude oil. This total petroleum hydrocarbon panel includes testing for volatile organic compounds such as benzene, toluene, ethyl benzene, and xylenes (BTEX). The Division believes the list of analytes required by proposed section 1724.7.2, subdivision (a), provide a sufficient informational baseline for fluid analysis. The Division has existing authority to require additional testing on a case-by-case basis if circumstances warrant.*
0004-45 1724.7.2(a): Define and use consistently "fluid" and "liquid" also as to liquid sources containing gases.
Response to Comment 0004-45: NOT ACCEPTED. *"Fluid" has been defined within these regulations to mean any material or substance which flows or moves, whether semisolid, liquid, gas, or steam. See section 1720.1, subdivision (d).*
0004-46 1724.7.2(c): Define representative – how close 2%, 5%, 25%...
Response to Comment 0004-46: NOT ACCEPTED. *The Division does not believe specification of a percentage for what constitutes a "representative" sample would add meaningful precision or clarity.*
0003-2 The revised regulations fall short of requiring adequate chemical testing, disclosure and reporting. New language in the revised draft that specifies that chemical analyses be representative of the liquid being injection requires more specificity in order to be enforceable. As currently written the Division would have no way of knowing whether the quality of injected fluid has changed unless an operator voluntarily reports it. We continue to call for a time-based (quarterly) frequency in order to account for changes to formation fluid chemistry over time, and other unforeseen changes, as well as clarify

that any change in which production wells provide produced water to an injection project should trigger new chemical testing.
Response to 0003-2: NOT ACCEPTED. *The Division does not agree that a fixed schedule of quarter-annual injection liquid testing for all injection wells would be more effective than the proposed performance standard of requiring a liquid analysis, updated as necessary to remain representative of the liquid actually injected. Proposed section 1724.10, subdivision (d), requires the operator to provide the Division with an updated representative chemical analysis of the injection liquid whenever the source of the injection liquid is changed, or upon request from the Division. Other existing law already requires operators to file monthly reports regarding the disposition of water in oilfield operations, including the source and volume of fluids produced from and injected into each well. See PRC section 3227, subdivision (a)(5).*
0003-19 1724.7.2(g): Commenter recommends adding as a requirement for liquid analysis an identification of the source(s) of all injected fluids, including but not limited to freshwater source(s), and/or production well(s), of any produced water injected.
Response to Comment 0003-19: NOT ACCEPTED. *Adding a separate regulatory requirement to report the source of all injected fluids is not necessary. Proposed sections 1724.7, subdivision (a)(3)(H) and 1724.10, subdivision (d), already require operators to provide a laboratory-accredited analysis of the injection liquid, updated as needed to ensure that the analysis is representative of the actual liquid injected. Other existing law already requires operators to file monthly reports regarding the disposition of water in oilfield operations, including the source and volume of fluids produced from and injected into each well. See PRC section 3227, subdivision (a)(5).*

1724.8 Evaluation of Wells Within the Area of Review

0009-3 1724.8: Commenter suggests a clarification that such evaluation of "all wells" would include the injection wells proposed for use in the injection project, in addition to offset wells found in the AOR. The commenters understand this is already how DOGGR intends to conduct AOR analyses but providing some explicit language to that effect would dovetail with the MIT Part II requirements in 1724.10.2, as both address the external mechanical integrity of injection wells. The MIT Part II section speaks to external mechanical integrity analysis after the injection wells begin operations, and the AOR section speaks to external mechanical integrity analysis before the injection wells begin operations. An explicit inclusion of injection wells in the AOR analysis would provide DOGGR with seamless pre- and post-injection external mechanical integrity assessment provisions.
Response to Comment 0009-3: NOT ACCEPTED. *The language of this section calls for "all wells within the area of review" to be evaluated. This includes any and all wells that are a part of the project as they are located within the area of review. Additional language to clarify the meaning of "all" is not needed.*

0011-5 1724.8(a)(1): Commenter renews the recommendation that the identification and assessment of potential migration pathways wells should be extended to all penetrations of the confining zone(s), including but not limited to wells or mines.
Response to Comment 0011-5: ACCEPTED. *The commenter's concern is addressed by the regulations. Section 1724.8 is focuses heavily on wells penetrating the AOR because those wells are the most likely conduits for fluid migration out of the approved injection zone. But the performance standard of section 1724.8(a) calls for evaluation of any potential fluid migration outside of the approved injection zone, and section 1724.7(a)(1)(B) requires identification of wells adjacent to the boundary of the AOR and identification of mining and other subsurface industrial activities within the AOR.*
0013-6 1724.8(a)(1)&(2): DOGGR must require plugging potential well conduits. The language, "may" require plugging and abandonment of existing wells "if [DOGGR] is concerned that the well has the potential to allow fluid to migrate outside of the approved injection zone." Evaluation and plugging and abandonment should be required in every instance a well could potentially act as a conduit for fluid migration, whether DOGGR is concerned about it or not. The provision as drafted leaves the door open to arbitrary enforcement.
Response to Comment 0013-6: NOT ACCEPTED. *Evaluation of all wells in the area of review is required under section 1724.8, subdivision (a)(1). Section 1724.8, subdivision(a)(1) provides that the Division "may" require wells to be plugged and abandoned because the Division may also require other actions to prevent fluid from migrating outside the injection zone, including monitoring or remediation.*
0008-6 1724.8(a)(2): The use of Bentonite or other technologies may be an alternative that returns the same or better results. Including options allows technology to develop and allows the use of other materials that in a specific situation may be a better engineering and/or business solution.
Response to Comment 0008-6: ACCEPTED IN PART. *The Division is aware that there may be alternatives to cement which would serve the same purpose for zonal isolation. Rather than attempt to delineate all the alternatives, section 1724.8(a)(3) allows for an alternative demonstration that a plugged and abandoned well within the AOR will not be a potential conduit for fluid migration outside the approved zone. Where a well has been plugged using materials other than cement, the operator must demonstrate to the Division that this performance standard has been met.*
0011-6 1724.8(a)(2): While Commenter appreciates the addition of a reference to the Division's existing plugging rules at 1723.1, it renews its recommendation that plugged and abandoned wells in the AOR should meet ***all*** the Division's existing plugging standards at Cal. Code Reg., tit. 14, §§ 1723-1723.8, and also reiterates that these regulations are outdated and do not conform to current best practices.
Response to Comment 0008-10: NOT ACCEPTED. *These standards have been set to establish containment and prevent fluid migration. Where a well does not meet these standards, the operator will be required to demonstrate how containment is maintained, or reenter and reabandon the well. Plugging and abandonment standards are being updated as part of a separate well construction rulemaking package.*

1724.10 Filing, Notification, Operating, and Testing Requirements for UIC Projects

0009-4 Add requirement in 1724.10 that wellheads on all injection wells be equipped with a pressure observation valve on the tubing and for each annulus of the well. One of the commenters' key recommendations on UIC generally is continuous annular pressure monitoring. The commenters understand that there are concerns about the cost of doing so, though we believe they would be marginal on top of DOGGR's existing proposed requirement for continuous injection pressure monitoring in 1724.10.4. However, even if DOGGR is not prepared at this time to require continuous annular pressure monitoring for all wells, the rule should require all wells to be equipped to allow annular pressure monitoring, as in Texas. Many operators will do this as a matter of course; some will do so as a matter of alternative MIT Part I compliance; and DOGGR has the right to require continuous annular pressure monitoring per proposed 1724.10(j). The commenters urge DOGGR to encourage this practice, which is one of the least expensive and most effective forms of well integrity monitoring, as widely as possible – requiring wells to be equipped to allow this type of monitoring is a threshold condition for increasing this smart and reasonable practice.
Response to Comment 0009-4: NOT ACCEPTED. *The Division does not have a regulatory need to always require continuous annular pressure monitoring, and therefore would not require that operators equip wells to do so. However, operators have the option to choose ongoing monitoring subject to further requirements.*
0009-5 Add linkage to DOGGR's general well construction rules in 1724.10. We have raised this point before – aside from requirements related to tubing and packer, the proposed rule does not specify the well control, casing, cementing, completion and related requirements for the construction of injection wells. This can quickly be remedied by a link to DOGGR's well construction rules. We repeat our suggestion that the Division should incorporate by reference compliance with its well construction rules for all new injection wells, and for existing injection wells, require remediation to current well construction standards or an explanation of how current well conditions meet the Division's performance standards for safety and environmental protection. Even simply requiring that new injection wells be constructed to current DOGGR well construction standards would be a positive development.
Response to Comment 0009-5: NOT ACCEPTED. *Operators remain responsible for compliance with all existing statutes and regulations, including the existing well construction requirements; a cross-reference within these regulations is not needed.*
0004-47 1724.10(a): Define "any" and "inconsistency"
Response to Comment 0004-47: NOT ACCEPTED. *These words are used consistent with their ordinary meaning as they appear in the dictionary. Additional definitions in this regulation are not needed.*

0004-48 1724.10(a): Provide table of temporal periods…operator must submit changes at least three weeks, 21 days, of the desired time of implementation…or is it ten days with an assumed no-objection decision if not responded to by the Division.
Response to Comment 0004-48: NOT ACCEPTED. *The Division does not see the need for specified temporal periods at this time. If a request is submitted with a desired date that cannot be achieved with sufficient time to process the request for approval, then it is not approved, and the operator may not proceed.*
0011-7 1724.10(b): Commenter opposes the proposed deletion of the requirement to obtain prior written approval to resume injection in an idle well.
Response to Comment 0011-7: NOT ACCEPTED. *The requirement to obtain prior written approval to resume injection in an idle well has been moved to section 1724.13. The requirement in section 1724.13(a)(8) 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. This section has been modified to provide that an operator may maintain approval for injection well while it is idle by communicating with the Division.*
0003-20 1724.10(c): The Division should post all injection data online within 10 days of receipt. The injection report shall include dates of injection, purpose(s) of injection, volume of injected fluids, source of injected fluids, daily maximum injection pressure, and all chemical additives injected, their purpose, mass, concentration, CASRN following the formal established under SB 4 for well stimulation fluids. The proposed regulations do not provide adequate specificity for what information must be included in the monthly injection reports.
Response to Comment 0003-20: NOT ACCEPTED. *PRC section 3227 already requires operators to report the source and volume of injected fluids, the regulations require continuous pressure monitoring and recording under Section 1724.10.4, the project data requirements under Section 1724.7 include a statement of the primary purpose of the injection project, and chemical information for additive used in a well that is proximal to water source wells is required to be disclosed. This information is a matter of public record and the Division is working to make it available online.*
0008-5 1724.10(d): As the responsible and permitted party the operator must submit the data and review the data prior to submitting it to the agencies. A laboratory is not the operator and should not be regulatorily obligated to provide data that is the operator's responsibility to provide.
Response to Comment 0008-5: NOT ACCEPTED. *Requiring certified laboratories to directly submit data 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. The burden is on the operator to ensure the laboratory submits the data, not on the laboratory.*
0011-8 1724.10(d): Commenter objects to the proposed revision removing the requirement to test the liquid being injected at least once every two years.

Response to Comment 0011-8: NOT ACCEPTED. *The fluid analysis must be done frequently enough to ensure that it is representative of the liquid being injected. For some projects, such as commercial disposal wells, this will be substantially more frequent than every two years, but for other more static projects it could be more than two years. DOGGR may request additional fluid analysis as part of the project review, which will take place no less than once every three years under Section 1724.6, subdivision (d).*
0003-21, 0011-9 1724.10(e): Disclosure of chemical additives must be required for all wells and all injection projects. The bifurcated requirements proposed in the regulations are not adequate. At a minimum, any injection well that passes through groundwater with beneficial uses must also be subject to the enhanced reporting requirements. While the option for the Division to expand this distance is a step in the right direction, when an operator injects chemical additives into the environment, including the subsurface, it must be reported and made public. If the oil industry wants the social license to operate, it should be willing to share this basic information – a requirement that operators easily comply with under SB 4 for well stimulation. We urge the Division to prioritize transparency and the public's right to know and require full reporting of all chemical additives.
Response to Comments 0003-21 and 0011-9: NOT ACCEPTED. *The Division does not generally have a need for chemical disclosure, as zonal isolation must be maintained regardless of the content of the fluid injected. The purpose of this requirement is to collect information that could be used to verify whether injection fluid is contaminating water supply wells. Obtaining information about chemical additives in injection fluid would help the Division and other regulators respond if contamination is reported in water supply wells located near injection wells.*
0006-8, 0012-9, 0014-8 1724.10(g): The proposed language [*requiring that the packer not be set below open perforations if the packer is set within the approved zone of injection*] is unduly restrictive given the diversity of California's oil and gas formations and recovery methods. For example, operators implement multiple wellbore configurations and operations strategies with dual injection wells, single selective assemblies, in-zone isolation and other techniques that help to target productive zones. The clarification of '100 vertical feet' and the addition of a Division-approved alternative configuration allow for scenarios such as horizontal wells that have proven difficult to configure in a manner that will allow for successful surveys given the limitations of conventional tools and equipment.
Response to Comments 0006-8, 0012-9, 0014-8: NOT ACCEPTED. *The regulation provides an opportunity for operators to demonstrate alterative configurations in section 1724.10(g)(2). The demonstration must be based on documented evidence that the well does not penetrate a USDW, that the well is completed with more than one string of casing cemented to the Division's satisfaction below the base of the lowermost USDW, or there is other justification to determine that all USDW, hydrocarbon, and anomalous zones can be protected without the use of tubing and packer.*
0009-6 1724.10(g): Require that injection wells be cemented to at least 500' above the injection zone. The commenters appreciate that DOGGR now proposes to require in 1724.10(g) that packers be set no more than 100 feet above the approved injection zone, but they should also be set in a cemented interval. Requiring that injection wells be cemented to at least 500' above the injection zone would

accomplish that goal, and could be effectuated by a requirement that injection wells comply with the existing rule in 1722.4 that all oil and gas zones and anomalous pressure zones be isolated with at least 500' of cement above those zones Existing injection wells that would not meet this criterion should have their cement bond evaluated with a showing of high quality cement for isolation of the injection zone, and that the cement top at a minimum is sufficient for packer to be set across a cemented section of the wellbore.
Response to Comment 0009-6: NOT ACCEPTED. *Injection wells are already subject to the construction requirements of section 1722.4 requiring cement to fill the annular space to at least 500 feet above oil and gas zones and anomalous pressure intervals. All wells within the area of review will be subject to evaluation of cementing records under 1724.8(a)(1), and the Division may require a cement evaluation log where records are inadequate or unreliable. The Division may also require remediation if there is concern that a well has the potential to allow fluid to migrate outside the approved zone of injection.*
0007-2 1724.10(h)(5): There are times when a well is not a risk as noted in this section but would be required to have remedial action conducted within 180 days. In this situation, Commenter would like to see more flexibility such as the ability to incorporate the well into the testing waiver plan as outlined in the proposed idle well regulations.
Response to Comment 0007-2: NOT ACCEPTED. *Wells placed on the idle well testing wavier plan must meet the definition of "idle," making the waiver plan an inappropriate alternative for wells that need remediation to continue injecting safely. Although a well may be low risk when operating, any need for remediation indicates that the well represents more risk than when it was in good condition; the deadline of 180 days protects life, health, property, and natural resources by ensuring that wells remain in good condition at all times.*
0003-22 1724.10(j): The Division should, on a monthly basis, collect and post relevant information such as this. Asking an operator to keep this information but not report it, is not appropriate and encourages incomplete data.
Response to Comment 0003-22: NOT ACCEPTED. *The information in section 1724.10, subdivision (k), can be useful for investigative and safety purposes, so the operator is required to maintain it, but it is only needed upon request. Because the Division does not need the data in all cases and it would involve additional document management by the operators and the Division without a clear purpose, it is not required.*
0008-7 1724.10(k): The suggestion is remove machine readable format instead of requesting a definition of a "machine readable format." These records no matter the method of recording them they can be provided to the Division upon request.
Response to Comment 0008-7: NOT ACCEPTED. *Data must be submitted in a machine-readable format; availability of the records is not enough if they are not in a format that can be accessed by the Division's digital systems.*

1724.10.1 Mechanical Integrity Testing Part One – Casing Integrity

0015-1 1724.10.1(a) 1724.10.2(b): Commenter appeals to the Division to author these regulations in a manner that protects drinking water without adding costly and disruptive testing. To do this, allow exceptions where no drinking water is present. This is a worthy approach, one that strengthens regulations while making best use of California's resources. The central focus of the UIC regulations is to ensure ongoing protection of underground sources of drinking water. So, where no USDW is present, mechanical integrity testing and fluid migration testing at start-up is appropriate, but repeated testing is simply too disruptive to California's oil & gas production. This is particularly true for cyclic wells that are not equipped with tubing and packer – and commenter alone has thousands of such wells. Commenter provides edits indicating that testing shall not be required for wells that neither penetrate a USDW nor whose Zone of Endangering Influence encompass a USDW.
Response to Comment 0015-1: NOT ACCEPTED. *Allowing injection at a pressure that might compromise the integrity of an injection well is inconsistent with the Division's mandate under Public Resources Code 3106, subdivision (a), to prevent "damage to underground oil and gas deposits from infiltrating water and other causes; loss of oil, gas, or reservoir energy, and damage to underground and surface waters suitable for irrigation or domestic purposes by the infiltration of, or the addition of, detrimental substances." 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.*
0004-49 1724.10.1(b)(4): Define "stable," "fluid," and "excess gases" in a fluid or liquid.
Response to Comment 0004-49: NOT ACCEPTED. *Proposed section 1720.1, subdivision (d), defines "fluid" as "any material or substance which flows or moves, whether semisolid, liquid, gas, or steam." Stable and excess gases are used consistent with their ordinary meaning and can be understood within the context of the pressure test required by this subdivision.*
0006-9, 0012-4, 0014-1 1724.10.1(b)(6): Commenter believes the proposed testing requirements and acceptance criteria need further refinement in order to align more closely with industry standards and does not believe the more restrictive parameters in the regulation increase the accuracy or validity of tests. Casing pressure tests conducted at 100 psi-300 psi are consistent across all identified published Class II standard annular pressure testing (SAPT) testing criteria. Under no circumstances should testing pressures be required to exceed 500 psi under the UIC program. The safety and environmental risks associated with surface pipe exceed those for downhole wells.
Response to Comments 0006-9, 0012-4, and 0014-1: NOT ACCEPTED. *The current requirement to test to MASP or 200 psi, whichever is greater, is one of the strictest in the nation, and the Division believes that an important precedent is being set. Specifically, the purpose of the test is to ensure the casing is unlikely to lose integrity under regular operating pressures. Thus, the maximum pressure tested*

becomes the maximum pressure which can be used during operations. If the well cannot stand a pressure test to MASP, then it should not be injecting at that pressure.
0007-3 1724.10.1(b)(6): This section is focused on surface pressure and seems unrelated to bottom hole pressure, which is an important factor in this testing. "…provided that the pressure test is conducted at an initial pressure of at least 200 psig ~~above surface pressure~~ above design process bottom hole pressure accounting for the hydrostatic fluid pressure of the fluid filling the casing. In no case should the required bottom hole test pressure approach the stress limit of the casing pipe. The maximum allowable process bottom hole initial pressure for the injection well, as determined under Section 1724.10.3, shall not exceed ~~the initial test pressure~~ the maximum pressure used during the most recent successful pressure test, adjusted for the hydrostatic pressure of the process fluid."
Response to Comment 0007-3: NOT ACCEPTED. *This change is not necessary. Under static conditions, the bottom hole pressure is equal to the surface pressure plus the hydrostatic pressure of the injection/process fluid. Where the operator believes that the surface pressure may cause unsafe conditions at bottomhole, the operator should test to the maximum safe pressure, which will then become the maximum approved surface injection pressure for the well.*
0009-8 Clarify requirement in 1724.10.1(b)(6) on MIT Part 1 testing pressure. The commenters read this section as allowing operators to conduct pressure tests at a pressure of their choosing (over 200 PSI), but that whatever pressure they choose will become the new MASIP for that well. If this is true, DOGGR should clarify this language to make this outcome more explicit.
Response to Comment 0009-8: NOT ACCEPTED. *The clarifying language commenter requests already appears in section 1724.10(b)(6), which specifies that the maximum allowable surface injection pressure for the well shall not exceed the initial test pressure used during the most recent successful pressure test.*
0012-2, 0014-2 1724.10.1(b)(6) and (b)(8): The first rule of pressure testing should be safety - every time pressure is applied to a fixed volume – whether a well, pipeline, tank or vessel, it is storing energy that can pose a safety and environmental risk. Therefore, the pressure used in testing should be (1) the lowest necessary to establish the integrity of the equipment being tested for the service to which it is put, and (2) no more than the pressure used to test other components connected to the equipment being tested. The Division's acceptance criteria should recognize that depth and temperature changes in a well connected to an oil and gas formation directly affect pressure testing and introduce fluctuations - without indicating any loss of integrity. While the Division has cited numerous EPA and state sources regarding pressure testing in its 15-day notice for the draft UIC regulations, we believe that the draft regulations propose the highest testing pressure among all of those resources cited and set acceptance criteria with the narrowest tolerances. Both of these introduce safety and operational concerns without providing meaningful further assurance of injection well integrity. Commenter notes that testing that creates false negatives costs industry significant money and lost injection barrels investigating repairs that are not actually necessary and forced repeat testing for wells of sound integrity to meet stringent requirements.

The more restrictive proposed parameters do not increase the validity of the test. a. The Division cited EPA Region 5 as the guidance document used to establish SAPT criteria, yet the EPA's guidance limits testing to 300 psi rather than the MASP requirements in the UIC draft regulations. b. Other published regulations account for the complexity of this testing and the temperature and pressure changes with depth in their requirements (max pressure, bleedoff, duration). These conditions are not unique to cyclic steam wells, and occur in other oil & gas formations, particularly at greater depths. c. The Division correctly uses the State Fire Marshal calculator to review pressure testing of surface pipe and evaluating acceptable leak rates for required testing. For example, modeling a typical Wilmington injector at a 10% pressure bleedoff results in a volume change of 1.44 gallons, or 0.046% of the annulus volume of the well. That miniscule change in volume would be a successful test under the tolerances set for surface pipe by DOGGR and other California regulatory bodies. These DOGGR approved and implemented practices indicate that a 10% bleedoff meets the testing criteria for surface pipe, and the same engineering practices should be applied to downhole pressure testing. d. Given the greater complexity of down hole testing of wells due to changes in depth and temperature, the tolerances should be the same as or less stringent than surface pipe. e. Applying unduly narrow tolerances to reject test results can disrupt waterflood operations and subsidence control and also diverts resources into repetitive testing and investigating marginal repairs of wells with sound integrity.
Response to Comments 0012-2 and 0014-2: NOT ACCEPTED. *The Division does not agree with commenter's assertions regarding the pressure used in testing. Instead, these UIC regulations require the pressure testing of wells at the same pressure as will be used, the maximum allowable surface pressure, for each individual well. Testing to MASP ensures that the well has the integrity needed to maintain safe containment during actual injection operations, which can take place at MASP. If a well cannot safely be tested to MASP, then it is also not safe to inject at that pressure. The tolerances used are consistent with the recommendations of US EPA region 5 and are known to be achievable in injection wells with good integrity.*
0005-2 1724.10.1(b)(7): Commenter suggests revising the term "highest" used to describe the location of well casing to a term more related to depth such as "deepest" or "shallowest." The current term of "highest" could be misinterpreted to reference the largest number or the structurally shallowest.
Response to Comment 0005-2: NOT ACCEPTED. *The term "highest" follows a list of items that are arrayed vertically in the wellbore; in context this can only be the structurally shallowest, thus more specificity is not needed.*
0001-4, 0006-11 1724.10.1(b)(8): Commenter recommends replacement of the phrase "a cyclic steam injection well" with the phrase "located in a thermal field." Commenter believes this change is warranted on the basis that any well located in a thermal field is likely to undergo thermal expansion. Limiting the exception strictly to "cyclic steam injection wells" does not account for the typical behavior of other wells located in a thermal field.

Response to Comments 0001-4 and 0006-11: NOT ACCEPTED. *Where the operator is having trouble obtaining a passing test result that is believed to be caused by thermal fluctuations, the operator should contact the Division for potential modification of the test parameters. Section 17.24.10.1(b)(9) provides that the Division may modify the testing parameters on a case-by-case basis if, in the Division's judgement, the modification is necessary to ensure an effective test of the integrity of the casing.*
0001-5, 0006-10 1724.10.1(b)(8): Commenter's technical analysis is that the 3% deviation mandated in the draft regulation will be difficult to comply with for deeper wells. We recommend adding language that sets the exception at 5% for wells deeper than 1000 feet.
Response to Comment 0001-5 and 0006-10: NOT ACCEPTED. *The Division received information regarding testing pressure from several jurisdictions and is confident that 3 percent is an achievable number. This percentage is used by the US EPA Region 5, as well as several provinces in Canada, suggesting that other jurisdictions have also found these thresholds achievable.*
0009-9 1724.10.1(b)(8): Consider whether the 3% loss requirement falls within a margin of error and could lead to false positive results. The commenters appreciate that DOGGR wants its MIT Part I pressure testing requirement to be especially rigorous, as evidenced by defining a failure as a change of three percent or more from initial pressure, as opposed to the standard ten percent. The commenters wonder, however, whether three percent might be within a margin of error in these tests, and whether this very low threshold might lead to costly false positive results from variations in temperature, vibration and pulsation. DOGGR may want to consider retaining the more standard ten percent threshold, and requiring continuous annular pressure monitoring instead to effectuate the Division's goal of enhanced injection well internal mechanical integrity standards.
Response to Comment 0009-9: NOT ACCEPTED. *This section includes a requirement in (b)(5) that the gauge used to record the pressure has an accuracy within 1 percent of the testing pressure. Use of this gauge should ensure that there are few false positives. The Division is confident that this 3 percent standard can be achieved as it is recommended by US EPA Region 5 in their pressure testing guidance.*
0012-4, 0014-3 1724.10.1(c)(2)(B): The requirement to maintain a nitrogen gas blanket (100 psi pressure) in the casing-tubing annulus of UIC wells introduces safety and operational risks associated with storage and handling of energized fluid. The system would be overly burdensome to maintain and introduces unnecessary safety risk related to the storage/handling of energized fluid. Commenters propose deleting this section, due to safety and operational concerns associated with maintaining pressure on the casing-tubing annulus of a well.
0006-12 1724.10.1(c)(2)(B): With the safety and operational concern associated with maintaining pressure on the backside of each well, commenter suggests eliminating this provision altogether.
Response to Comments 0012-4, 0014-3, and 0006-12: NOT ACCEPTED. *Positive pressure on the backside is necessary to detect small leaks, especially from the packer, which may not be detectable with fluid level tests. This alternative allows for lower pressure and lower frequency testing; the continuous monitoring is needed to ensure the alternative remains as stringent as the default*

requirement. Operators are not required to employ the alternative pressure monitoring option under 1724.10.1(c).
0006-13 1724.10.1(c)(2)(C): The citation to subdivision (d)(2)(B) is incorrect. The correct citation is (c)(2)(B) [100 psi of nitrogen maintained in annulus].
Response to Comment 0006-13: ACCEPTED. *Thank you for catching this item; it has been corrected in the final draft.*
0006-14, 0012-5, 0014-4 1724.10.1(c)(2)(C): Commenter recommends that the regulations be revised to specify that notification alarms that monitor for and signal positive pressure increases are an acceptable means of demonstrating ongoing mechanical integrity. With Division approval, certain of our members have made significant investment installing alarm systems across multiple fields and risk losing the benefit of that investment. Operators are able to reach alarmed wells in minutes and act on the alarm as needed before the pressure in the well exceeds the test pressure. Similarly, more frequent pressure testing (than otherwise required by the regulations) should also be a recognized method to demonstrate ongoing mechanical integrity.
Response to Comments 0006-14, 0012-5, 0014-4: NOT ACCEPTED. *The ability to respond to an alarm when a problem arises is not the same as demonstrating ongoing mechanical integrity; instead it is a response to loss of integrity and would not meet the requirements of this section. The list in this section is a list of examples and is not intended to be exhaustive. Where an operator believes an alternative will represent a stronger demonstration of ongoing mechanical integrity, they should propose the alternative to the Division with supporting data.*
0006-15, 0012-6, 0014-6 1724.10.1(c)(2)(D): Some members of commenter's association do not measure and record the casing pressure with Division-approved systems – rather they monitor casing pressure and trigger an alarm if limits are met.
Response to Comments 0006-15, 0012-6, 0014-6: NOT ACCEPTED. *This section provides an alternative to the default casing pressure test required under subdivision (a) of this section. It includes a requirement for a single pressure test, with ongoing monitoring in lieu of additional testing. Measurement and recording of casing pressure is an important part of this requirement as it allows the Division to monitor activity taking place in the well. An alarm notification system does not provide a record of the pressures that the well has experienced and is not sufficient to meet the requirements of this section. As this is an alternative to the default, operators are free to choose not to use this option if they do not have the equipment to meet its requirements.*
0011-10 1724.10.1(d): Commenter opposes the Division's proposal to allow alternate mechanical integrity testing methods. The Division has provided no evidence that the example methods – or any alternative methods – will provide equivalent assurance of mechanical integrity.
Response to Comment 0011-10: NOT ACCEPTED. *The alternative methods proposed for acceptance are commonly used and accepted tests throughout the oil and gas industry. They are designed to test mechanical integrity in a variety of ways, but all are accepted as valid tests for integrity. Furthermore,*

under section 1724.10.1, subdivision (d), the alternate test must be at least as effective as the standard pressure testing to demonstrate well integrity.
0009-10 1724.10.1(d): Establish timeframes and frequencies for MIT conducted under this section, and grant this exception only sparingly. This new proposed method for operators to establish internal mechanical integrity does not appear to have built-in timeframes and frequencies for conducting tests, as do the options offered in 1724.10.1(a) and (c). While the commenters realize that (d) is intended as a flexible catch-all, some indication of an outer limit of frequency would be appreciated (every five years at a minimum, for example). However, we must caution that this exception to regular pressure testing be granted only sparingly. Pressure testing can reveal pinhole leaks, for example, that none of the other logging tools listed in (d) would find. We would hope to see nearly all UIC wells in California pressure tested at least every five years, with alternative testing methods approved only in extraordinary circumstances.
Response to Comment 0009-10: NOT ACCEPTED. *The frequency of repeat testing would be part of the proposal that operators must submit when requesting an alternative under this section. Because this catch-all section may cover testing that must be done at a greater or lesser frequency to be as effective as the pressure test, the Division cannot specify a default timeframe for testing under this section.*
0006-16, 0012-7, 0014-5, 0002-2 1724.10.1(e): Some members of commenter's association have a number of SAPT exemptions that have been reviewed and approved by the Division based on the risks associated with a given operating field (e.g. age of wells, presence of fresh water, etc.). Commenter believes the regulations should be revised to include the option for the Division to review and approve variances/exemptions on a case-by-case basis employing the same risk-based approach. More frequent radioactive tracer surveys can be required as a condition to such approvals in order to adequately assess risk over time.
Response to Comments 0006-16, 0012-7, 0014-5, and 0002-2: NOT ACCEPTED. *One of the goals of this rulemaking process has been to implement regulations that will avoid inconsistent application of requirements upon operators. Where flexibility exists for a case-by-case evaluation of the application of those requirements to a specific operator, it has been specifically delineated in the regulations. Because periodic casing pressure tests are a core requirement of the regulations, with parameters consistent with US EPA Region 5 requirements, no variance will be permitted from the requirements of this section except as specifically articulated in the text.*

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

0007-4 1724.10.2(a)(2): Commenter recommends this sentence be changed to clarify that the Division intends for a test to be conducted within one year for a well status from "low-use cyclic steam injection well" to "injection well." Currently it could be interpreted to require testing even though the well was not in use ("stopped").

Response to Comment 0007-4: NOT ACCEPTED. *All operators that wish to maintain approval to inject must continue to comply with all requirements of the regulations, including the mechanical integrity testing as described in this section, even if the wells are not in use as an injector ("stopped"). The default requirement for all wells is a two-year frequency; commenter's edits would change it to a five-year frequency inappropriately. Instead the five-year frequency is reserved for those cyclic steam wells that have been determined to meet the definition of low-use cyclic steam injection well based on the lower risk associated with intermittent use as an injector.*

0011-11

1724.10.2(b): Commenter recommends that the Part II MIT be performed prior to injection and then at least yearly thereafter, with no exception. We are not aware of any scientific studies or data demonstrating that different injection wells experience mechanical integrity issues at different rates, let alone that the rates of mechanical integrity issues are consistent with the proposed testing frequencies. Increasing the testing frequency for "low-use cyclic steam injection wells" to every five years runs counter to best practice, given that mechanical integrity problems in wells that are used less frequently may go undetected for longer periods of time. Like idle wells, low-use wells should be subject to the same testing frequency as active wells.

Response to Comment 0011-11: NOT ACCEPTED. *The types of testing required under Section 1724.10.2 (radioactive tracer, noise log, temperature survey) must be done after injection has begun because they measure activity in the well. All three of these tests are dependent of fluid moving through the well during injection; without injection there is no noise, no significant temperature changes, no way to see tracers moving, etc. Thus, Part II MIT appropriately is scheduled for three months after injection begins when the well is operating under normal conditions. Furthermore, the Division considered requiring Part II MIT on annual basis but determined that a default frequency of once every two years would be equally effective to achieve its regulatory purposes and substantially less burdensome for affected operators. More frequent testing may be required on a case-by-case basis if the Divisions identifies a need to do so. Finally, low-use cyclic steam wells do present different regulatory concerns because they 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.*

0013-9

1724.10.2(b)(2): Low use cyclic steam injection wells should be subject to the same testing restrictions. DOGGR has not provided any rationale for a separate category of "low use" cyclic steam injection wells. Unless and until evidence supports a separate standard for these wells, they should be subject to the same regulations. Moreover, it will be difficult for DOGGR to enforce this secondary standard for a newly and needlessly created additional classification for an injection well.

Response to Comment 0013-9: NOT ACCEPTED. *As explained in the Final Statement of Reasons, 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. Furthermore, the Division is confident in its ability to regulate these wells differently.
0001-6, 0006-17 1724.10.2(d)(4): Commenter recommends deleting the new language added in (d)(4) of the section pertaining to Part Two of the MIT. The newly proposed requirement requires temperature data to be collected as a prerequisite of a radioactive tracer survey. Commenter believes the prerequisite temperature survey step is not necessary because temperature data taken during an RA survey is not indicative of containment, but rather is used by the vendor for validating tool integrity. Accordingly, the information yielded from the survey is not likely to be relevant to the purpose of the regulatory requirement.
Response to Comments 0001-6 and 0006-17: NOT ACCEPTED*. As indicated by commenter, the temperature survey is a necessary step to verify the integrity of the tool being used to perform the survey. Although the Division does not have need for the results of the survey itself, the temperature survey is an important part of valid RA test procedures and protocols and is included to ensure this important step is not skipped during the test.*
0008-8 1724.10.2(d)(4): Commenter recommends replacing "total depth" with "top perforations". The use of top perforations addresses a potential issue in an operator not being able to get to the well TD.
Response to Comment 0008-8: NOT ACCEPTED. *Where an operator cannot get to total depth, there may be damage that will affect the ability of the well to keep fluids confined to the approved zone. It will also make plugging and abandoning the well more difficult and indicates a higher risk well that must be more carefully monitored. Thus, the appropriate requirement is for total depth to ensure integrity throughout the wellbore.*
0012-11, 0014-13 1724.10.2(d)(4): The primary objectives of this testing are to ensure that there is no fluid migration behind the casing, tubing and packer and that injection fluid is isolated from USDW/contained in the zone. A survey across the full length of the well is not required in order to demonstrate either of these objectives. Extending a survey across the full length of the well diverts resources, creates costs and creates testing confusion in situations where a test cannot reach the bottom of the well, even though it is well below any USDW. The regulations should clearly define and limit scope to the minimum requirements needed to demonstrate mechanical integrity and conclude a passing test.
Response to Comments 0012-11 and 0014-13: NOT ACCEPTED. *A survey of the full length of the well is needed to demonstrate mechanical integrity of the entire wellbore. An inability to reach the bottom of the well can be an indicator of potential casing damage that may negate the ability of the well to prevent fluid migration between zones. In addition, although USDW is one of the resources which must be protected, it is not the only resource. Hydrocarbon reservoirs must be protected from infiltrating water or other detrimental substances and the life and health of operators and the public must be protected.*
0001-7, 0006-18 1724.10.2(d)(6): Commenter recommends deleting the newly added language in (d)(6) of the section pertaining to Part Two of the MIT. From a technical perspective the requirement to run a tubing rate check within 200' of the top and bottom of tubing does not add to the quality of information relating

to confinement from the RA Tracer/inert gas survey. It is possible to show confinement in the injection zone without going below 200 feet.
Response to Comments 0001-7 and 0006-18: NOT ACCEPTED. *This addition will help capture rates that will differ due to variable tubing conditions such as scale buildup.*
0006-19 1724.10.2(d)(13): It is unclear whether subdivision (d)(13) is the only subdivision applicable to steam injection wells, or whether IGPs for steam injection wells are also the subject to the requirement of subdivision (d)(1)-(d)(12).
Response to Comment 0006-19: NOT ACCEPTED. *All sections of this proposed regulation apply to steam injection wells except section (d)(12), which specifically exempts steam injection wells. Subdivision (d)(13) provides a separate requirement for steam injection wells for that aspect of the test. Nothing in the language would suggest that the other sections (d)(1) through (d)(11) do not apply to steam injection wells; all provisions apply unless specifically exempted.*

1724.10.3 Maximum Allowable Surface Pressure

0011-12 1724.10.3(a): Commenter renews its recommendation that the Division should provide much greater specificity about what data, modeling, and other information operators need to provide to demonstrate that "injected fluid will remain confined to the approved injection zone, the higher pressure will not initiate fractures outside the approved injection zone or propagate existing fractures outside the approved injection zone, and the higher pressure will not otherwise threaten life, health, property, or natural resources."
Response to Comment 0011-12: NOT ACCEPTED. *As discussed in the Initial Statement of Reasons, confinement of injected fluids to the approved injection zone is the core principle by which the Division, and these proposed regulations, evaluate and ensure the safe operation of underground injection projects. The Division will consider any data that operators believe will support their argument that they have met these standards. Some examples of data that would support such a finding include well logs, step-rate tests and gradient calculations, data from observation wells, and geologic modeling.*
0011-13 1724.10.3(a): The following must be mandatory for any projects injecting above the fracture gradient: • Full public disclosure of all chemicals used in the injection project; • Restrictions on the use of hazardous, toxic, or otherwise harmful chemicals; • Comprehensive chemical analysis of injectate at least every 3 months; • Rigorous groundwater monitoring; • Modeling and monitoring to track the subsurface extent of induced fractures and injected fluids; • State of the art modeling of and monitoring for surface expressions; • Injection and production (if any) must occur only through tubing set on a packer; • Part I & II MITs at least every 6 months; • PAL reviews at least once per year.

Response to Comment 0011-13: NOT ACCEPTED. *The Division does not see any specific regulatory justification for the imposition of these requirements on projects exceeding the fracture gradient. Where specific issues with surface expressions have been identified, the Division is imposing rigorous reporting and control requirements and will work with operators to prevent damage to life, health, property, and natural resources.*
0004-50 1724.10.3(a): Define: “effective” “fracking” “more appropriately accounts” “demonstration”
Response to Comment 0004-50: NOT ACCEPTED. *The term “fracking” does not appear in the regulations and thus does not need to be defined. The other terms are used consistent with their ordinary meaning; technical or specialty definitions are not needed here.*
0004-51 1724.10.3(a): Will Division “no-objection” approval apply to such “may” decisions?
Response to Comment 0004-51: *No, a no-objection standard will not apply to “may” decisions. “May” decisions are places where the Division has the discretion to perform the action or not perform the action, based on its own discretion and statutory requirements. Unless a “no-objection” standard is specifically articulated, operators may not proceed until they have obtained approval from the Division.*
0006-20, 0012-8, 0014-7 1724.10.3(a)(1): Commenter appreciates that the Division has agreed to incorporate friction into the approved MASP calculations. However, the proposed regulations provide that friction loss must be calculated in a highly conservative manner using the largest possible tubing size for the well. Commenter believes that: (1) the application in general should be science based; (2) calculations have been verified to be conservative with historical studies provided to the Division; and (3) there are already conservative factor built into gradient (x0.95) and friction calculations since they do not account for the friction in perforations or equipment restrictions. With these conservative factors in mind and the proposed approach of calculating MASP and associated friction on a well-by-well basis, Commenter proposes that the that the actual tubing size(s) be used rather than introducing an additional conservative factor into the overall MASP calculations. Wells with tapered strings can be modeled to account for varying friction coefficient in each taper of the tubing string.
Response to Comments 0006-20, 0012-8, 0014-7: NOT ACCEPTED. *The incorporation of friction loss is subject to Division approval. Furthermore, any friction factor must be calculated based on the new coated tubing of the largest diameter that will be used for injection. This calculation is conservative by design to ensure that there is not unapproved injection above fracture pressure.*
0010-2 1724.10.3(a)(1): Commenter believes that the inclusion of the 0.95 multiplier will greatly reduce the ability to waterflood in many of their fields. 26% of Commenter’s current water flood completions operate above the 95% of frac gradient. Lowing the injection rate to meet the 95% of frac gradient would result in a loss of approximately 100,000 bwpd. Considering that one of the purposes of waterflood is pressure maintenance to reduce subsidence, a reduction of that amount could hinder our ability to do so. Commenter would like to see the 0.95 multiplier removed from the MASP calculation.

Response to Comment 0010-2: NOT ACCEPTED. *A modifier other than 0.95 is subject to Division approval on a well-specific basis. This section allows an operator to request a higher multiplier subject to Division approval.*
0004-52 1724.10.3(c): Define "estimated" "given" "representative tests" anywhere (vertically and laterally), area (=AOR?). Must update AOR geologic conditions
Response to Comment 0004-52: NOT ACCEPTED. *The terms used here are used consistent with their ordinary meaning and do not need to be given a technical or special definition. Operators will need to update AOR geologic conditions any time conditions change, or new information becomes available.*
0015-3 1724.10.3(e)(1): The draft language calls for wells to be shut-in prior to testing. Shutting in wells in a flood-drive field would result in a pressure depletion that is not representative of operating conditions. Testing under a shut-in, pressure-depleted condition would yield artificially low frac gradient results. For this reason, holding a minimum rate of injection during step-rate tests would yield more representative results.
Response to Comment 0015-3: NOT ACCEPTED. *The procedure for the step rate test requires that the well be shut-in long enough to allow the bottom pressure and the formation pressure to equalize. However, if the operator can demonstrate stabilization at a reduced but constant injection rate prior to the start of the step rate test, the Division may allow the test to commence. If the well is stabilized at a reduced injection rate, the stabilization period should be long enough to achieve a steady-state to allow the test to proceed. There should also be a pressure stabilization at each constant rate before stepping up to the next rate.*
0009-12 1724.10.3(e)(5): Clarify that the purpose of the bottom hole pressure recording is in part to determine reservoir pressure and flow capacity and thus provide insight into well performance. DOGGR should append (5) with "to record instantaneous shut-in and fall-off pressures." A requirement to record pre-injection pressure and shut-in pressure informs the operator as to what bottom-hole pressures they should be recording. Recording these two pressures would provide the operator and DOGGR an indication of the original reservoir pressure as well as a rate of decline, which provides insight into formation permeability. These provide an indication of whether a well is likely to pressure up or operate on vacuum. This edit would not entail additional work on the operator's part – it is simply a clarification of DOGGR's proposed pressure monitoring requirement.
Response to Comment 0009-12: NOT ACCEPTED. *These sections include the steps which must be taken during a pressure test and already include the pressure before the first step and the pressure after the last step. The additional language recommended by Commenter does not appear to add any clarity to the requirement and is not needed.*
0007-5 1724.10.3(e)(6): Commenter believes a pressure reading every 30 or 60 seconds would be sufficient in this section, instead of every second.
Response to Comment 0007-5: NOT ACCEPTED. *High frequency data recording is often used as a substitute for continuous recording and must be in the smallest increments possible to fully gather real-time data available from a testing protocol. These testing standards and protocols are necessary*

to ensure that MASP determinations are supported by clear, consistent, and reliable step rate test data.

0004-53

1724.10.3(e)(7), 1724.11(b)(3): Require real time digital/internet/body cameras and videos with audio for all inspections/witnessing with/without District inspectors.

Response to Comment 0004-53: NOT ACCEPTED. *Video recording of operational activities would not add value to regulatory enforcement and is thus unlikely to be cost effective given the cost of equipment and maintenance. For a mechanical integrity test, the value of witnessing is limited because the primary enforcement tool is evaluation of the log and testing results. Furthermore, the inclusion of the 24-hour notice requirement for step-rate tests will facilitate more witnessing by Division staff.*

1724.10.4 Continuous Pressure Monitoring

0011-14

1724.10.4: Commenter generally supports the proposed requirements of this section but objects; to subsection (5), which would allow the requirements to be waived if "facilities are configured in a manner that effectively prevents injection into the injection well above the maximum allowable surface injection pressure." Injecting above the MASP is only one of the many possible issues that could lead to a loss of mechanical integrity. Continuous pressure monitoring is the most effective way to detect mechanical integrity problems and should be required for all injection wells.

Response to Comment 0011-14: NOT ACCEPTED. *The primary purpose of the requirement for continuous monitoring of injection pressure is to provide a record of all injection such that the Division can confirm that injection is not taking place above MASP. Consistent with this section's primary purpose to monitor injection pressures, The Division may waive the requirement to continuously monitor when facilities are configured in a manner that effectively prevents injection above MASP.*

0014-10

1724.10.4(a)(1): Commenter does not believe continuous pressure monitoring for cyclic steam wells is necessary. Cyclic steaming should be excluded from continuous monitoring requirements as monitoring during a production cycle is unnecessary.

Response to Comment 0014-10: NOT ACCEPTED. *The primary purpose of the continuous monitoring requirement is to ensure that wells do not inject above MASP. Thus, the regulations permit cessation of monitoring if the injection line is disconnected from the well. If operators would like to cease monitoring during production cycles, they should take this step to demonstrate to the Division that it would be impossible for them to inject.*

0003-23

1724.10.4(b): Commenter urges a faster timeline for implementation of this section and recommends a deadline of July 1, 2019.

Response to Comment 0003-23: NOT ACCEPTED. *These regulations and other rulemaking packages that are being imposed on operators will be significantly burdensome in cost and require rig and testing service providers to expand their capacity rapidly. For this reason, the Division recognized that some requirements would need to be phased in to allow operators to budget for compliance. With*

regulations likely to be effective April of 2019, a July 2019 deadline would not provide sufficient time for operators to come into compliance with this requirement.
0006-21, 0012-10, 0014-9 1724.10.4(b): The regulations are written to provide operators with a 2-year timeframe to accomplish this task. Certain of our members have literally thousands of injectors, presenting a significant project. Commenter proposes a risk-based approach where wells without a USDW are granted an additional 2 years for installation.
Response to Comment 0006-21, 0012-10, and 0014-9: NOT ACCEPTED. *Existing regulations (1724.10) already require operators to have a pressure gauge or recording device available at all times and many operators already have gauges permanently installed on their wells. Operators that have a large number of wells that need these gauges installed should begin as soon as possible, even before the effective date of the regulations, but the Division is confident in the ability of operators to provide gauges for all their injection wells within the 2-year period allotted.*

1724.11 Surface Expression Prevention and Response

0003-24 1724.11: In general, we support the increased safety requirements in this section. However, the exception for low energy seeps is inappropriate. Any surface expression is not appropriate, and the incomplete definition of a low energy seep (such as the lack of temperature or volume thresholds) make this exemption unenforceable and up to the interpretation of the operator. If a surface expression occurs and the Division determines that it is caused by an injection project, the PAL shall be revoked and injection into that formation by that operator shall be permanently prohibited. Unless there are real consequences for operators who cause surface expressions, a violation of 1724.11(a), this section will be abused and used as a way to get around that requirement.
Response to Comment 0003-24: NOT ACCEPTED. *A "low-energy seep" is a surface expression where the operator has demonstrated that the fluid coming to the surface is low-energy and low-temperature, is not injected fluid, and is contained and monitored in a manner that prevents damage to life, health, property, and natural resources. The operator must demonstrate all of these elements to the Division, and the operator does not have the authority to unilaterally decide what is or is not a low-energy seep.*
0007-6 1724.11: Ceasing injection does not allow an operator to identify the well that may be contributing to the problem. A best practice is to shut down injectors sequentially. Commenter recommends allowing short term (no more than 60 minutes of injection) into the injectors that have been identified for immediate shut-in.
Response to Comment 0007-6: NOT ACCEPTED. *The first goal in dealing with a surface expression is to find a way to stop the flow, and the shut-down of injectors within a certain radius is an efficacious means of rapidly achieving this goal. However, with the advance written approval of the Division, the operator may be allowed to conduct limited injection for the purposes of identifying the cause of the surface expression.*

0007-7 1724.11: A Petroleum Engineer is the right type of individual who should sign off in this section. We do not feel licensed civil engineers are going to have expertise in root cause analysis of surface expressions.
Response to Comment 0007-7: NOT ACCEPTED. *This section references the California Business and Professions Code which is focused on the licensing of professional engineers. It includes not just civil engineers, but all licensed engineers including petroleum engineers. It is the responsibility of each licensed professional to ensure that they are appropriately licensed to perform the engineering tasks at issue in compliance with that code.*
0004-54 1724.11(a) and (b)(1): Define "any" and include vertical physical ground surface changes, adequate, prevent…
Response to Comment 0004-54: NOT ACCEPTED. *These terms are used consistent with their ordinary meaning and do not require additional definition in these regulations.*
0004-7 Ground surface monitoring must include the entire AOR and monitor for both uplift and subsidence.
Response to Comment 0004-7: NOT ACCEPTED. *Section 1724.11(b)(1)(A) provides flexibility by allowing operators to propose ground monitoring systems for Division approval.*
0004-55 1724.11(b)(1): Provide microseismic (-3rm) and laser-based surface (1mm) monitoring systems for ground movements.
Response to Comment 0004-55: NOT ACCEPTED. *Operators are free to propose any ground monitoring system that they believe will meet the requirement of this section to develop a surface expression monitoring and prevention plan. The Division does not want to limit operators to specific technologies. This allows flexibility for the operators and allows the regulation to "grow" as new technologies are developed.*
0004-53 1724.10.3(e)(7), 1724.11(b)(3): Require real time digital/internet/body cameras and videos with audio for all inspections/witnessing with/without District inspectors.
Response to Comment 0004-53: NOT ACCEPTED. *Video recording of operational activities would not add value to regulatory enforcement and is thus unlikely to be cost effective given the cost of equipment and maintenance. For a mechanical integrity test, the value of witnessing is limited, because the primary enforcement tool is evaluation of the log and testing results. The inclusion of the 24-hour notice requirement will facilitate more witnessing by Division staff.*
0004-56 1724.11(d): Commenter recommends edits to this section to require immediate cessation of injection if a surface expression has been detectible for more than five minutes (instead of 5 days) and to require the Division to determine a shut-in radius if the surface expression continues to flow for more than one hour (instead of 10 days).
Response to Comment 0004-56: NOT ACCEPTED. *Operators must immediately notify the Division if a surface expression occur, and must immediately cease injection in a well when the wellhead is within 150 feet of that expression. A surface expression will not respond immediately to changes in the*

injection activities of the wells around it. Instead, it is necessary to wait a few days after ceasing injection in the first radius to see the effect on the flow of the surface expression. Commenters edits would effectively eliminate the escalating process, which may hinder investigation into the causes of the surface expression.
0004-57 1724.11(d): Define immediate vs five days
Response to Comment 0004-57: NOT ACCEPTED. *"Immediate" means to take action without delay, at this moment. "Five days" means five days. These are common words used consistent with their ordinary meaning.*
0004-58 1724.11(e): Commenter recommends changing this section from a "may" direct injection to cease to a "shall" when the Division "believes" (rather than "finds reason to believe") that the injection well is causing or contributing to a surface expression.
Response to Comment 0004-58: NOT ACCEPTED. *Commenter's edits would require that the Division "believe" something to be true, rather than have reason to believe it is true, setting a higher bar for Division intervention than is desired in this context.*
0004-59 1724.11(h): Commenter would add the Division to the requirement for notification in the case that a surface expression discharges oil in a reportable quantity.
Response to Comment 0004-59: NOT ACCEPTED. *Section 1724.11(c) requires operators to notify the Division in the case of surface expression; this section is specifically about reporting to the California Governor's Office of Emergency Services.*
0004-60 1724.11(h): Define "spill" vs. "expression", advance
Response to Comment 0004-60: NOT ACCEPTED. *The word "spill" only appears in the clause directing reporting to the California Governor's Office of Emergency Services. This refers to their regulations regarding what constitutes a spill of reportable quantity and is not open to interpretation by the Division. A definition for surface expression is provided in section 1720.1(n). "Advance" simply means "prior to" or "before." It is used consistently with its ordinary meaning and does not require additional definition.*

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

0004-61 1724.14: Commenter would rename this section to include production as well as injection and require continuous monitoring rather than daily monitoring. Reporting should include magnitude 1.0 or greater with a hypocenter occurring within a spherical radius of 10,000 feet of any active injection well and assign such earthquakes to the most probably fault plane within the area of reference.
0013-4 Seismic hazards can cause spills and leaks. The proposed regulations should contemplate that.
Response to Comment 0004-61 and 0013-4: NOT ACCEPTED. *This section has been removed from the regulations. The Division is working to develop a seismic notification system and seismic data analysis*

project that will meet the goals of this section. Commenters and Division staff are in agreement that centralized tracking and analysis by a government sponsored agency will be more efficient and accurate than tracking by individual operators.