UNDERGROUND GAS STORAGE REGULATIONS
PUBLIC COMMENT SUMMARY AND RESPONSE

First 15-day Public Comment Period:
February 12, 2018 through February 27, 2018

INTRODUCTION

After consideration of the input received regarding the proposed Requirements for California Underground Gas Storage Projects rulemaking action during the initial public comment period held from May 19, 2017, to July 13, 2017, the Department of Conservation's Division of Oil, Gas, and Geothermal Resources (Division) revised the proposed regulations. The Division then published a revised version of the proposed regulations and opened a first 15-day public comment period to receive input on those revisions. This first 15-day public comment period began on February 12, 2018, and ended on February 27, 2018.

Over the course of the first 15-day public comment period, the Division received numerous comments.
To facilitate the process of reviewing and responding to comments, the Division assigned to each comment a unique numerical signifier. 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	Patricia McPherson, Grassroots Coalition
0002	Donna and Joseph Goldstein
0003	Richard Bratkovich
0004	INGAA
0005	Center for Biological Diversity
0006	Jim Summers
0007	Patty Glueck
0008	Southern California Gas
0009	Geologic Maps Foundation
0010	Natural Resource Defense Council
0011	Central Valley Gas Storage, LLC; Gill Ranch Storage, LLC; Lodi Gas Storage, LLC; Wild Goose Storage, LLC
0012	Environmental Defense Fund and Pipeline Safety Trust
0013	Los Angeles County Fire Department
0014	Jim Chaconas, InterAct Projects
0015	Pacific Gas & Electric

ACRONYMS AND OTHER SHORTHAND REFERENCES

AOR	Area of Review
API RP	American Petroleum Institute Recommended Practice
CalEPA	California Environmental Protection Agency
CalOSHA	California Occupational Safety and Health Administration
CARB	California Air Resources Board
CCST report	Report issued by the California Council on Science and Technology "*Long-Term Viability of Underground Natural Gas Storage in California*" released January 2018
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CPUC	California Public Utilities Commission
Division	Department of Conservation, Division of Oil, Gas, and Geothermal
ERP	Emergency Response Plan
ISOR	Initial Statement of Reasons
Legislature	Legislature of the State of California
MIT	Mechanical Integrity Testing
National Labs	Lawrence Berkeley, Lawrence Livermore, and Sandia National Laboratories
PAL	Project Approval Letter
PHMSA	Pipeline and Hazardous Materials Safety Administration, Dept. of Transportation
QRA	Quantitative Risk Assessment
PRC	Public Resources Code
RMP	Risk Management Plan
the Act	California Administrative Procedures Act
UGS	Underground Gas Storage
ZEI	Zone of Endangering Influence

COMMENTS IN SUPPORT

0004-5, 0015-34
Commenters support the risk-informed process and phased implementation currently outlined in the Proposed Rule for assessing existing wells and designing new wells, determining appropriateness of safety valves, monitoring/evaluating corrosion, and verifying integrity of wells and reservoirs.

0010-31
§1726.1(a)(2), (a)(5) and 1726.2: Commenters support the proposed changes to the definitions of "caprock" and "reservoir." Commenters support the proposed requirements of section 1726.2 and the Division's proposed revisions.

0005-45
§1726.3: Commenter is generally supportive of requiring Risk Management Plans (RMPs) and is glad to see the requirement that RMPs for existing UGS projects must be submitted within six months of the effective date of this section.

0008-22
§1726.3: Commenter supports the Division's efforts to enhance the safety of UGS facilities through risk management and is supportive of an RMP that considers the evaluation of the most important risk categories and failure scenarios associated with the operation of a UGS project, as well as the application of a Quantitative Risk Assessment (QRA) model to supersede prescriptive requirements and better inform a more appropriate prioritization and frequency interval of aspects such as mechanical integrity testing.

0015-35
§1726.3: By applying risk management practices, determinations can be made in each operator's RMP on the appropriate well design and construction to protect the integrity of each well. Commenter appreciates the flexibility in the revised draft for operators to develop an implementation schedule based on risk assessment findings and the seven-year phase-in period.

0010-32
§1726.3(a) and (c): Commenters support the proposed addition specifying the timeline for existing projects to submit an RMP. This is critical to reducing the public health and safety and environmental threats posed by these gas storage facilities, all of which predate modern environmental laws and regulations and best practices for design,

operation, maintenance, monitoring, and abandonment. Commenters also support the proposed revisions and additions to subdivision (c).

0005-46

§1726.3.1: Commenter is pleased to see that the Emergency Response Plans (ERPs) shall be reviewed and updated after key personnel changes and no less than once every three years, and that the local emergency response entities will be able to review and provide input on the plans.

0005-47

§1726.4(a)(4)(A): Commenter is pleased that the regulations now prohibit exceeding the fracture pressure gradient of the reservoir or confining strata, similar to section 1724.10(i)

0010-33

§1726.4(g): Commenters support the Division's proposed addition of a timeframe to submit updated project data for projects in existence when these requirements go into effect.

0015-36

§1726.4.3: Commenter appreciates the revision to this section to require only submittal, not approval, of a Records Management Plan for Division review. The plan submitted to the Division will establish the appropriate processes and procedures for maintenance of the records according to each operator's unique circumstances and aligning with company-wide records management strategies.

0010-34

§1726.6.1 and 1726.8: Commenters support the proposed requirement of these sections, including the proposed revisions.

Response to comments 0004-5, 0015-34, 0010-31, 0005-45, 0008-22, 0015-35, 0010-32, 0005-46, 0005-47, 0010-33, 0015-36 and 0010-34*: Noted. Thank you for your active participation in the process of developing and improving these proposed regulations.*

GENERAL COMMENTS

0004-1, 0015-14

Any regulations adopted by California must be consistent with the Pipeline and Hazardous Material Safety Administration (PHMSA) rule and guidance, including PHMSA's published Underground Natural Gas Storage FAQs. Commenters recommend that the Division adopt the consensus standards of the American Petroleum Institute Recommended Practice (API RP) 1170 and API RP 1171 by reference in order to align with PHMSA's Interim Final Rule.

***Response**: ACCEPTED IN PART. The proposed regulations are consistent with and are more stringent and comprehensive than the minimum federal standards. The Division consulted API RP 1171 as a starting point in developing the proposed regulations. (Recommended Practice 1170 was not consulted because there are no solution-mined salt caverns used for natural gas storage in California). The Division's proposed regulations would include additional detail and definition as to requirements in comparison to API RP 1171, which tends to apply requirements based on more open-ended case-by-case assessments. Examples of greater definition and stringency in the Division's proposed regulations include more stringent and defined well construction standards, a clear regulatory framework for risk management planning, more detailed requirements for mechanical integrity testing and monitoring, more frequent testing of safety valves, and stronger Division oversight through project data requirements.*

PHMSA's January 18, 2017 Interim Final Rule establishing minimum standards for underground natural gas storage facilities addresses many of the same issues as the Division's proposed regulations. Both sets of regulations are intended to minimize the environmental and public health risks associated with such facilities. However, PHMSA minimum standard only provide a floor for regulation of underground gas storage projects, and the Division's proposed regulations are necessary to achieve greater protection of health and safety and to meet statutory requirements for the regulations of underground gas storage projects under state law.

0005-1

Commenter suggests that the Division must consider whether UGS facilities belong near people or natural resources; commenter does not believe they do, and recommends a significant buffer zone between these facilities and nearby sensitive receptors or natural resources. Natural gas facilities have a significant history of acute dangers. While it is important to try and minimize these dangers, it is also important to evaluate whether they pose ongoing chronic impacts and risks as well. Therefore, prior to issuing any discretionary permits or approvals, the Division should conduct health and seismic risk assessments, as well as review under the California Environmental Quality Act (CEQA).

***Response**: NOT ACCEPTED. The proposed regulations require a Risk Management Plan for each UGS facility that includes evaluation of threats and hazards associated with operation of the underground gas storage project and identification, prevention, and mitigation protocols that effectively address those threats and hazards. Consideration of proximity to people is inherent to the RMP process.*

0005-3

The regulations must clarify that hydraulic fracturing and injection outside the tubing are prohibited. These dangerous practices further threaten the integrity of old wells and poorly understood hydrogeology, and undermine the safety otherwise gained by the proposed regulations. As a result, they must be prohibited in all UGS facilities.

***Response**: NOT ACCEPTED. The Legislature of the State of California (Legislature) exempted well stimulation treatments used for routine maintenance in UGS wells from the reporting and disclosure requirements of Public Resources Code (PRC) section 3160, specifically allowing for these treatments. Provided that the treatments can be performed without exceeding the fracture pressure, this activity is authorized by statute and permissible under the proposed regulations. Similarly, injection outside of tubing is not prohibited by the proposed regulations because SB 887's requirement for two mechanical barriers does not prohibit a well configured with double casing from injecting without tubing. The requirement in section 1726.5(b)(1)(B) that the secondary barrier not be exposed to the withdrawal or injection flow is sufficient to prohibit injection outside of tubing where tubing is part of the primary mechanical barrier.*

0007-7

There is nothing in the proposed regulations that mentions the need for consequences when a utility does not adhere to the rules.

***Response**: NOT ACCEPTED. As provided by statute, civil penalties may be imposed on an operator who is in violation of any statute, regulation, or permit condition. Failure to follow Division orders may also subject an operator to civil penalties. The proposed regulations do not stand alone, but are part of a statutory and regulatory scheme that includes multiple provisions of the PRC and California Code of Regulations (CCR). Where an enforcement power already exists in statue, it does not need to be duplicated in these proposed regulations to be legally effective.*

0015-8

Gas storage is essential for commenter to reliably serve gas to its customers. Commenter appreciates the changes in the revised draft that help alleviate some reliability concerns by providing an appropriate phase-in timeframe for construction and design standards and allowing greater flexibility for some integrity testing. However, the proposed regulations will still necessitate taking wells out of service for significant periods of time, thereby severely limiting the ability to inject or withdraw from the storage facility to meet system reliability needs. In addition, the nature of this work being conducted simultaneously across all storage facilities in California may impact operators' access to the industry resources needed to perform drilling and maintenance activities in a timely manner. Limited industry resources may further extend the timing of the outages and further impact the ability to provide reliable service.

***Response**: NOT ACCEPTED. The Division is aware that operators will be required to develop effective plans for well upgrade and remediation and is confident that the seven-year time frame provides sufficient flexibility for off-peak service reductions and drilling of new wells if needed. The Division recognizes that the proposed regulations represent a compromise between the need for reliable and cost-effective service and the statutory mandate to protect life, health, property, natural resources, and the environment, and will work with operators to overcome specific challenges as they are encountered, but the minimum performance standards of these proposed regulations must be achieved.*

0015-9

The costs to implement this new safety regulation will be incremental to the costs commenter currently recovers in rates from its customers. In order to recover its costs to comply with these new regulations, commenter will need to seek recovery through the CPUC ratemaking process. Commenter requests that the Division acknowledge that operators should be allowed to recover in rates the significant costs to comply with its new regulations.

***Response**: NOT ACCEPTED. Advisory commentary to the CPUC regarding exercise of its ratemaking authority is outside the scope of this rulemaking action. The Division has considered the potential economic impacts based on the proposed regulations and has done its best to balance the need for risk mitigation and safety with the need to keep cost burdens low. The Division acknowledges that there will be costs associated with the proposed regulations, and that these costs may include a minor increase in the price of natural gas and electricity for consumers.*

ALISO CANYON FACILITY

0006-1
An immediate shut down of the gas storage facility at Aliso Canyon is necessary. People are still getting sick. A root cause analysis, adequate health study, monitoring of gases and toxin, and the disclosure of composition of gas blowout and continuing leaks must be done. If the operator has been found in fraud, petition for the State for temporary receivership until an adequate operator can take over.

Response*: NOT ACCEPTED. The Legislature, California Public Utilities Commission (CPUC), California Air Resources Board (CARB), and the Division are working together on the ongoing response to the Aliso Canyon incident. For its part, the Division has conducted a comprehensive safety review of all the wells at Aliso and has shut-in all wells which failed the extensive testing that was required. Evaluations, testing, and remediation continue. Like all UGS operations, the Aliso Canyon facility must be brought into compliance with the new regulations on the schedule provided for in the regulatory text.*

0009-1
Inviting public comments on the geologic hazards at the Aliso Canyon gas storage field, such as the Santa Susana fault, is premature as the Aliso Canyon Gas Storage Field Geologic, Seismologic and Geomechanical Studies funded by the operator have not been released for public review and comment. Commenter's concerns about the fault-displacement hazard at the Aliso Canyon storage field and the objectivity and transparency of the evaluation and review process to date are summarized in the journal Science (3 November 2017, Vol 358, Issue 6363).

Response*: NOT ACCEPTED. The purpose of this public comment period is not to solicit input from the public regarding geologic conditions at Aliso Canyon. As explained in the notice published on February 12, 2018, the purpose of this public comment period is to solicit input regarding revisions to proposed regulations that would establish a comprehensive statewide regulatory framework tailored to address operational concerns specific to UGS projects. The Notice of Proposed Rulemaking Action and the Initial Statement of Reasons discuss in detail the objectives of and need for the proposed regulations.*

SECTION BY SECTION COMMENTS

1726.1 DEFINITIONS

0001-1

§1726.1: Commenter expresses concern that many terms and definitions become points of contention during litigation concerning leaks, and thus need to be defined. These terms include “area of influence”, “area of concern”, “any potential conduit”, “high pressure”, and “capture area.”

***Response:** NOT ACCEPTED. The only language referenced by commenter that appears in the text of the proposed regulations is “any potential conduit,” which can be understood based on its ordinary meaning, and does not need to be more specifically defined. The other terms referenced by commenter appear in the Initial Statement of Reasons, as part of broader explanatory discussion. Regulatory definitions for these terms are not necessary for the purposes of this rulemaking, and the Division believes these terms are sufficiently clear within the context of their use in the rulemaking record.*

0005-4

§1726.1(a)(1): Commenter supports a definition of Area of Review (AOR) that is based on geologic features, but finds this alone to be insufficient. The definition should be based on a determined zone of endangering influence (ZEI) as well. (40 CFR §146.6). The ZEI includes consideration of the potential for fluid migration, taking into account the specific factors that can affect migration, including the pressures in the injection zone. In addition, the use of hydraulic fracturing and well stimulation techniques, seismicity, and surface geological changes, must also be included as specific considerations when defining the AOR. The AOR was intended to determine whether the storage and injection of gas, fluids, or chemicals at various pressures have “a potential for contaminating underground sources of drinking water through wells, faults, or other pathways that penetrate an injection zone.” Recent studies have increasingly documented the risks caused by injection on seismicity, surface expressions, and other geologic changes; and, gas, waste water, or oil leaking into the soil and air through idle or broken wells, and other potentially dangerous conditions. All of these conditions can, in turn, affect the size of, and impact on, the ZEI.

***Response**: NOT ACCEPTED. The proposed definition for the AOR includes the project and surrounding areas that may be subject to its influence, and is focused on any and all geologic characteristics of the UGS reservoir. Unlike the ZEI, it is not a mathematically calculated radius, but a qualitative and quantitative analysis of those* *areas that may be impacted by project operations including, but not limited to, injection and well stimulation. The AOR as proposed is broad enough to encompass the ZEI, which is focused solely on the protection of underground sources of drinking water, and provides consideration for the additionally required protections to life, health, property, the environment, and natural resources that are not included in the ZEI.*

0010-1
§1726.1(a)(1): The guiding principle for determining the AOR should be to delineate the area in which leakage from the approved storage zone could occur and to identify potential pathways by which injected or displaced fluids could migrate out of the approved storage zone. It should take into account the entire geologic system used to store natural gas underground. When these goals are not explicitly stated, the phrase "surrounding areas that may be subject to its influence" is vague and subject to interpretation. Commenters recommend the addition of "area encompassing and surrounding an underground gas storage project in which stored fluids may be able to migrate outside the approved storage zone into unauthorized zones such as other geologic formations, USDWs, or the atmosphere" as well as other edits designed to make this definition more explicit.

Response*: NOT ACCEPTED. Commenters' proposed definition is excessively broad. First, the proposed regulations explicitly require in multiple sections that the project demonstrate that fluids will not migrate out of the storage reservoir. Migration into the atmosphere is a secondary result of containment loss and is part of the RMP, but should not be included in the AOR, which is focused on the subsurface geology included in and affected by the project. In addition, requiring the AOR to encompass the entire geologic system would be impractical; many geologic systems are connected for hundreds of miles and could include everything from the original source of hydrocarbons to tectonic plate features, none of which would be relevant to the regulatory standard. The proposed regulatory definition of AOR is focused on those areas that may be subject to influence due to project operations. This proposed definition can be understood using the ordinary meaning to be any and all areas that might be affected by project-related hazards, including all those areas of concern to commenters.*

0008-11
§1726.1(a)(6): Commenter recommends revision of the last sentence of this definition to include the language "An underground gas storage project…" for definition consistency.

Response*: ACCEPTED. Language has been updated as recommended by commenter.*

1726.2 APPROVAL OF UNDERGROUND GAS STORAGE PROJECTS

0002-3
§1726.2(a): A retrofit of existing well sites must be addressed within any Project Approval Letter (PAL) and that letter must be submitted discussing not only the current configuration irrespective of prior approvals (No grandfathering regarding safety), but the need to update, retrofit, and correct any shortfalls identified, whether this is a new, in-process, or planned facility. This section must clearly state that this is retroactive on any well field.

Response*: NOT ACCEPTED. Existing PALs do not relieve operators of an obligation to remain in compliance with regulatory requirements as they are updated; specific language making these requirements retroactive is not needed in these proposed regulations. Existing projects will be required to bring all wells into compliance with the new regulatory standards for well construction within 7 years, and the RMP must include a well-by-well hazard analysis and risk mitigation protocols.*

0005-2
§1726.2(b) and (c): The Division's failure to enforce regulations has resulted in significant risks. The regulations need to clarify enforcement authority with respect to these requirements. There should be penalty provisions for operators who do not first obtain a PAL, or who operate outside the conditions of an existing PAL. For instance, under section 1726.2(b), the Division will review projects to verify adherence and periodically review the terms and conditions of the PAL. The Division must clarify how often each of these reviews will occur, and how many violations of the PAL will result in suspension or rescission of a PAL. Similarly, under section 1726.2(c), the Division must clarify what conditions will trigger the written notice requiring operations to cease, or whether only certain operations will trigger such a letter. Is the duty to send notice mandatory under certain conditions, or is it always discretionary? Clarifying when and how the Division will take enforcement action is critical to ensuring the effectiveness of the proposed regulations. First, such clarity helps the regulated operators understand exactly when and under what conditions it may be subject to penalties or enforcement action. Second, the proposed regulations will only be as strong as the Division's enforcement.

Response*: NOT ACCEPTED. The proposed regulations, in section 1726.2(b), communicate the Division's intention to review UGS projects periodically, but not less than once every three years. In most situations, a default three year frequency of review* *will be sufficient to ensure that existing PAL conditions remain effective to prevent damage to life, health, property, natural resources, or the environment. The Division may require more frequent review for specific projects where a need for extra scrutiny to ensure safety is known or anticipated. Any feature of operations which is inconsistent with the PAL, including the requirement to be in compliance with existing regulations, is considered a violation of law. The Division has various statutory enforcement authorities, including the ability to issue an order to suspend operations immediately, if warranted by the circumstances. The Division's authority to issue civil penalties for violations of law is found in PRC sections 3236.5.*

1726.3 RISK MANAGEMENT PLANS

0002-5, 0003-1, 0012-3, 0013-2
§1726.3: Commenters request that the requirement for "prevention" protocols, which was replaced with "mitigation" protocols throughout this section, be reconsidered. Generally, prevention refers to proactive risk management planning, practices, and other actions to control a hazard before it occurs. Mitigation involves practices or actions to reduce or control a hazard once it has occurred. To provide for greater safety and comprehensive control of hazards, "prevention" should be reinserted so that both prevention and mitigation protocols are required. This is the formulation used by the API RP for gas storage, and is used in risk reduction analyses across industries. The Division should call on operators to grapple with both possibilities of risk reduction – mitigation and prevention – throughout the risk management planning process.

***Response to Comments 0002-5, 0003-1, 0013-2, 0012-3**: ACCEPTED. The word "prevention" has been added throughout the section to ensure that the requirements for the RMP include both prevention and mitigation protocols as appropriate.*

0005-14
§1726.3: The RMP should include requirements to conduct a root cause analysis after significant releases. The results of the analysis should be publicly available online. Identification and prioritization of risks, threats, hazards, and mitigation should include the results of root cause analyses. In addition, prioritization of risk mitigation should be based on recognized, independently vetted methodologies.

***Response**: NOT ACCEPTED. The RMP is focused on the prevention and mitigation of harm, including initial emergency response to serious incidents. Post-incident response is determined on a case-by-case basis depending on the type and seriousness of the incident and the resulting or potential harm. Where a cause is known, the performance* *of a root-cause analysis would not be an effective or efficient response. As required under SB 887, documents and data submitted to the Division pursuant to these proposed regulations, and not determined to be confidential, will be made available to the public via the Division's website. In addition, prioritization of risk mitigation is based on level of risk and likely effectiveness of the methodology selected. Where proposed mitigation methods are unlikely to achieve the performance standards they will not be approved, but operators are encouraged to be innovative in the development of their RMP protocols; limiting options to independently-vetted methodologies would be too restrictive.*

0005-16
§1726.3: The RMP should require identification of scenarios for existing and potential community and worker exposures to harmful and toxic air pollutants and should include protocols and mitigation measures for reducing those risks.

Response*: NOT ACCEPTED. The goal of the proposed regulations is to provide clear performance standards and minimum criteria for an effective RMP, and leave operators with maximum flexibility to determine the best approach to compliance. Threats to workers and nearby communities are among the things that an effective RMP may identify and address, but the Division does not intend to prescribe the inclusion of specific prevention and mitigation protocols along the lines commenter suggests. To ensure that RMPs are effectively developed and implemented based on site-specific risk assessments completed on a well-by-well basis, a project specific plan is required.*

0005-18
§1726.3: The RMP should include a publicly accessible database of all chemicals used during regular operations and in "off-normal events." Information should include the unique Chemical Abstract Service Registry Number, the mass, the purpose, and the location of use. Studies of the community and occupational health risks associated with this chemical use during normal and off-normal events should be undertaken.

Response*: NOT ACCEPTED. The natural gas injected into and withdrawn from a gas storage reservoir is high quality, processed, commercial gas from producers outside the state. As such, its contents and chemical make-up are generally known, as it has been processed and odorized prior to transport under federal law. The Division has not identified a regulatory need for such chemical disclosure.*

0005-15

1726.3: The RMP should include protocols and mechanisms for worker input and involvement in ongoing risk assessment and management, including protocols and mechanisms for workers to anonymously report potential threats and hazards. All employees must be empowered and encouraged to report any circumstances that could lead to leaks, corrosion, integrity failure, or other conditions that could pose a risk.

***Response**: NOT ACCEPTED. These comments point to a level of involvement in the internal management of companies that the Division does not intend to pursue. The goal of the proposed regulations is to provide clear performance standards and minimum criteria for an effective RMP, and leave operators with maximum flexibility to determine the best approach to compliance.*

0005-17

1726.3: The RMP should include a publicly accessible database of reported leaks and threatened leaks; emissions and air monitoring data; near-miss performance metrics; maintenance and safety requests made; corrective actions taken or not take; outcomes and results; the management individual accountable; and results of unannounced random onsite inspections.

***Response**: NOT ACCEPTED. Where such information and data has been submitted to the Division, the information will generally be available to the public through the Division website. It is not necessary to describe those practices in regulation.*

0005-6

1726.3(a): The RMP should identify a process requiring the operator to conduct a review and reassessment of the risk assessment and prevention protocols; however, the Division should specify minimum requirements for such periodic review and reassessments. We are supportive of the Division reviewing the RMP every three years. In addition, however, the Division should require that operators continually and iteratively assess alternative technologies and processes in order to incorporate the least hazardous approaches and technologies.

***Response**: NOT ACCEPTED. The proposed regulations require the operator to provide a schedule for regular updates to its risk assessment and mitigation protocols as part of the RMP; to prescribe a specific schedule would vitiate the site-specific, condition-responsive nature of these updates. The RMP will be reviewed no less than once every three years and will be updated as needed as part of the review process. Where new* *technologies become available and cost-effective, operators and Division staff will work together to incorporate them safely into the RMP and its protocols.*

0013-1

§1726.3(a): A written deficiency notice should be issued to the operator with a compliance date for correcting identified deficiencies. Providing a required procedure for issuing a deficiency notice with a compliance data allows for consistency in applying and complying with the regulations, as well as for accountability and enforcement purposes.

Response*: NOT ACCEPTED. The proposed regulations afford the Division flexibility in communicating with operators in order to ensure that RMPs satisfy the regulatory requirements and to allow for any deficiencies in an RMP to be cured as efficiently and effectively as possible.*

0015-15

§1726.3(a): The intent of API RP 1171 and other guiding standards in this arena is the RMPs should be developed at the mitigation and practice level rather than a field specific level. Application of the mitigations and the practices may be applied differently based on the relevance of risk and condition, i.e. field specific. Commenter requests the language be revised to accept a single plan.

Response*: NOT ACCEPTED. PRC section 3181 requires an RMP focused on each well, with site-specific information and well-by-well hazard analysis. With the number of wells involved in most projects, this means that a multi-field plan would likely be too unwieldly to effectively implement without losing the individual well focus required by statute. In addition, each location has unique hazards and characteristics that are better addressed through a field-specific approach. The requirement for a project-specific plan does not prevent operators from actively managing their protocols at a corporate level using consistent standards, provided that schedules and implementation procedures in the site-specific RMP are based on the requirements of a well-specific prevention and mitigation plan.*

0015-16

§1726.3(a): Commenter interprets the Division's request for authority to approve a plan to suggest the approved plan contains all necessary elements. Commenter requests the Division remove the language requiring review and approval. The operator should develop a plan that includes the requirements laid out and tested upon audit. If review and approval is included, it should only be to ensure that the RMP includes all of the sections required by this section.

***Response**: NOT ACCEPTED. Approval of the RMP by the Division is a statutory requirement of PRC section 3181. PRC section 3181 does not prescribe a specific procedure for approval, but the Division believes that a review consisting solely of a checklist for the materials listed in PRC section 3181 would be insufficient to meet the goals of SB 887 and of these proposed regulations. For example, PRC section 3181 requires the RMP to identify and plan for mitigation of threats and hazards in order to ensure internal and external mechanical integrity, not just to verify that the risk integrity loss has been evaluated, or integrity testing has been planned. Thus, it is insufficient for the Division to check off an RMP that has a plan for risk mitigation without evaluating whether or not it will successfully mitigate risk. The performance standards of the proposed regulations require a comprehensive analysis of the RMP and its ability to meet these standards.*

0013-3
§1726.3(b): Commenter suggests changing “effectively mitigated,” to “effectively controlled” so as to include the concepts of both prevention and mitigation.

***Response**: NOT ACCEPTED. Based on other comments received, the proposed section has been rewritten to require risks be “identified and prevented or effectively mitigated.” This change incorporates the concepts of both prevention and mitigation as suggested but does not use commenter’s recommended language.*

0015-17
§1726.3(b): The Division’s requirements should fully include the criteria and data needed to confirm that storage reservoirs and wells demonstrate integrity. Commenter requests the Division remove discretionary requirements, as any alterations to mitigation program funding is part of a rate case and deviations from the planned program executions could impose significant costs beyond CPUC authorized expenditures.

***Response**: NOT ACCEPTED. At the time an RMP is initially approved, the Division will ensure the plan covers existing site conditions and uses best practices with cost-effective technologies to accomplish its purposes. These purposes will include ongoing verification of reservoir and well integrity. As site conditions change and best practices evolve, RMPs must be adapted accordingly. Retention of discretionary authority to* *ensure that an approved RMP be tailored to the specific situation of each UGS project is necessary to best implement the Division's regulatory mission.*

0004-2, 0015-1

§1726.3(c): Prescribed prevention and mitigation protocols should be removed from this section to ensure that it is focused on risk assessment requirements. Consistent with API RP 1171, the appropriate prevention and mitigation protocols should be determined by the outcomes of the risk assessments, as outlined in the operator's RMP.

***Response**: NOT ACCEPTED. The proposed RMP requirements will ensure that minimum protocols for known hazards are included. Where an operator using QRA can demonstrate that no specific protocol is needed, no prevention or mitigation protocols will be required, but these items must, at minimum, be discussed in the RMP with the QRA findings supported by data and other evidentiary support.*

0005-8

§1726.3(c): In addition to the requirements for the methodology listed in the regulation, the methodology must include: 1) standards and protocols for identification of risks to workers as well as community health risks, taking into account the population density near UGS facilities; 2) Engineering, natural, *and human and organizational/safety culture* factors that affect the extent of and severity of threats, hazards, and risks; and 3) protocols for development plans to identify and use the least hazardous alternatives to toxic chemicals used onsite for normal and off-normal events.

***Response**: NOT ACCEPTED. The RMP requires operators to consider all risks associated with their well operations, beginning with an identification of hazards and a quantification of the associated risk for the most important potential accident scenarios. Thus, the risk of impact on the community and workers from exposure to harmful chemicals would be assessed as part of the mitigation of each identified scenario. The revised draft of these proposed regulations also includes the requirement to take human and organizational/ safety culture factors into account in section 1726.3(d)(12); engineering and natural hazards are listed for consideration in sections (d)(1) through (d)(16). A requirement to identify and use the least hazardous alternative for toxic chemicals is NOT required by the proposed regulations or by statute, but if an operator intends to use toxic chemicals in its UGS project operations, the hazards associated with the intended use of those chemicals are among the risks that must be prevented or mitigated under an RMP.*

0012-1

§1726.3(c)(1): On the subject of compliance with these new rules for existing facilities, we recognize that significant work is needed, possibly even enough to fill the seven years provided in the current draft, but compliance should be prioritized for high-risk wells and wells in high-risk areas.

***Response**: NOT ACCEPTED. The proposed regulations already include a requirement for prioritization of risk mitigation efforts based on potential severity and estimated likelihood of occurrence of each threat. Compliance requirements that would set priorities outside of this formulation would be contrary to the QRA method that is best suited to satisfy the statutory requirements and regulatory goals for the RMP.*

0008-1

§1726.3(c)(1): Commenter proposes a revision to the text in this section to clarify what commenter believes the Division's intended for the RMP to address, which should not be limited to the "most important potential accident scenarios", but inclusive of the "most important risk categories and failure scenarios", which is consistent with section 1726.3(c)(2).

0013-4

§1726.3(c)(1): There are no parameters or definitions provided for the "most important" potential accident scenarios. The regulations should specify the minimum requirements, such as the worst-case scenario release, and alternative release scenarios. Additionally, there should be a set of defined parameters used for these scenarios, such as wind speed, stability class, topography, offsite impacts, etc., to provide for relevant and constructive offsite consequence analyses. This would provide clear and consistent requirements for all operators.

0015-18

§1726.3(c)(1): Commenter suggests changing "most important potential accident scenarios" to "risk scenarios" as the consequence of evaluated event scenarios has the potential to range in consequence and frequency for given parameters (i.e. safety, environment). Commenter understands the intent of this clause would be for an operator to capture and evaluate the likelihood of relevant scenarios on a reoccurring basis to ensure proper mitigation and controls are in place and effective.

***Response to Comments 0008-1, 0013-4, 0015-18**: NOT ACCEPTED. The existing language, as proposed, is consistent with the QRA language that was provided by the National Labs and the recommendations of the CCST report. The Division is satisfied* *that this language is sufficiently clear and that it will better advance the regulatory goals identified in the ISOR.*

0008-2, 0011-1

§1726.3(c)(2): This section requires that an RMP include a Quantitative Risk Assessment (QRA) of the probability of threats and hazards and their consequences, using an appropriate methodology identified by the operator that includes components specified in the proposed regulations. To provide a better understanding of this revised RMP risk assessment methodology, commenters suggest that the Division conduct a workshop to address this topic *and* meet with each operator individually to provide feedback on the submitted RMPs to specifically identify deficiencies with respect to the new requirements. The workshop and one-on-one meetings should be scheduled soon after the new regulations are adopted (or, if possible, even before the final regulations are adopted) to provide operators with as much time as possible to develop the revised RMP.

Response*: ACCEPTED. Division staff are working to determine the appropriate schedule for a QRA workshop and will coordinate with operators to provide in-person analysis of their submitted RMPs. The Division intends that this not be a one-time consultation, but an ongoing collaboration between operator and Division staff to develop and maintain an RMP that meets the regulatory performance standards and is updated as needed to ensure effective prevention and mitigation of harm.*

0015-2

§1726.3(c)(2): The revised draft includes a new requirement for QRA of the probability of threats and hazards and their consequences. While commenter supports the concept of such quantitative assessment, this is still a developing area and the tools and data necessary to perform a QRA are not yet fully available. It is therefore premature to include QRA as a prescriptive requirement in regulation at this time. Instead, commenter recommends that this be an area operators continue to look into and incorporate as tools and methodologies are developed. The oil and gas industry and academia are actively pursuing research in this field – for example the California Energy Commission is currently funding research on Natural Gas Storage Infrastructure Safety and Integrity Risk Modeling. Elements of QRA may be employed; however, these methods are new and have yet to be tested. For many operators, risk assessment is typically performed using a combination of qualitative and semi-quantitative methods resulting in a relative rank evaluation. Commenter asks the Division to recognize this is a maturing process, even in the pipeline context, and remove “quantitative” risk assessment from regulation until proven a reliable and viable concept.

***Response**: NOT ACCEPTED. The language used in the QRA requirements section was provided by the National Labs and is consistent with the language recommended in the CCST report. The Division acknowledges that QRA may be in a nascent stage, and will work with operators to ensure that it is used meaningfully for effective risk assessment. The Division is confident that QRA will be a meaningful tool for RMP development, and the Division anticipates that the proposed regulations will provide an incentive for operators to assist in further development of QRA through implementation and lessons learned.*

0015-3

§1726.3(c)(2)(A): It is not clear how an estimate of uncertainties in numerical values is intended to be evaluated or how this would reasonably be estimated. Any method, qualitative or quantitative, includes uncertainties. Additionally, it is not clear how attempts to estimate numerical values would add value to the analysis. Commenter recommends removal of the language requiring estimates of uncertainties in numerical values.

***Response**: NOT ACCEPTED. QRA numerical values are not guesses; they are quantities derived from verifiable and evidence-based data that lead to reasonable determinations of probability and severity of impact. When completing a QRA, the operator will need to assign quantitative values to each identified threat and hazard. Those values will include a probability of occurrence, and a quantification of the severity of harm that could result from an occurrence. Elimination of all uncertainty is not an expected function of QRA. An operator who performs a QRA will provide the quantitative results as well as a discussion of any uncertainties that might affect the calculation, such as unique geology or lack of robust historical data. Some operators may need to retain a consultant with expertise in quantitative analysis to assist them in proper use of QRA analysis during the development of their RMP.*

0015-4

§1726.3(c)(2)(B): Commenter suggests striking this clause entirely as equipment failures, whether caused by external or internal triggers, and operational errors, are defined as threats in industry and PHMSA adopted guidance, i.e. API RP 1171. These items are not associated with threats and hazards rather these are individual threats.

***Response**: NOT ACCEPTED. Commenter is correct that an equipment failure or operational error is itself a threat that must be considered and mitigated. However, this subdivision is focused not on the threat itself, but on those externalities that might* *increase the probability of a threat occurring, or increase the impact of that threat. For example, the failure of a gauge or a collision with the wellhead are potential threats that must be assessed and mitigated. But the proposed section would also require consideration of how the failure of a gauge or a collision with the wellhead might increase the probability and potential impact of other, more serious threats, such as loss of well integrity leading to a leak. The requirement of this subdivision is to consider compounding factors in a chain of events, not just the threat itself.*

0013-5

§1726.3(c)(2)(B) and (c)(2)(C): The goal of hazard identification is to objectively and systematically identify and evaluate potential paths of failure and latent conditions which may lead to accident. Many industrial accidents are caused by seemingly benign and often overlooked hazards which cascade to catastrophic events or releases. In addition to principal equipment failures, therefore, hazard identification should systematically identify all potential paths of failure first, and then evaluate the severity of consequence(s) and likelihood of failure(s) to determine the relative role of each hazard for assigning the appropriate safeguard protections to control the hazard. Commenter recommends including a requirement for "identification of all potential paths of failure, including the series of events which may lead to the failure…" and "identification of the engineered or natural features that *may* affect the extent of consequences..."

***Response**: NOT ACCEPTED. The proposed section generally proceeds as commenter recommends – the hazard identification system identifies accident scenarios, and then evaluates the probability and consequence of those potential scenarios to assign appropriate safeguards to that scenario. However, the Division believes that it is impossible for the operator to consider "all potential paths of failure" and will not create a regulatory standard that cannot be achieved or enforced. Instead, as recommended by the National Labs and the CCST report, the requirements for QRA analysis focus on the most important potential accident scenarios including recognition of external events, such as equipment failures and engineered or natural features, that could affect the probability and/or magnitude of potential consequences.*

0015-5

§1726.3(c)(2)(C): Commenter recommends clarifying this section with the following edits: "Identification of the *controls (*engineered or natural*) that mitigate* ~~features that most affect the extent of~~ the consequences…" Commenter agrees that as part of the risk assessment you need to know which mitigations are currently in place and how those are addressing threats and hazards. As required in the subsequent section, these mitigations should be further evaluated to determine if they can be strengthened to reduce, manage, or monitor risk.

***Response**: NOT ACCEPTED. This language change is not appropriate given the structure of the proposed section. Proposed subdivision (c)(2)(C) is focused on the specific requirements of QRA. It does not deal with mitigation of hazards (required in proposed subdivision (c)(3)), but with the evaluation of the surrounding environment (natural and manmade) and how that environment might increase the extent of a potential hazard. For example, if a well is near a road, the volume and type of traffic on the road would affect the likelihood of an accident with a vehicle, and could affect the seriousness of the impact. The proximity of a natural oil seep or other natural hazard could increase the chance of contamination of the reservoir with foreign fluids, increasing the chance of integrity loss and potentially increasing the seriousness of a leak. Thus, the proposed section is appropriately focused on those items that impact the quantitative assessment of risk rather than mitigation, which is addressed in subdivision (c)(3). Where existing prevention and mitigation measures are in place, they would be included as part of the "engineered or natural" features affecting consequence, and/or could be considered after the initial risk assessment of the base condition as planned measures that have already been implemented.*

0015-19
§1726.3(c)(3): Commenter requests the language "…and cost effectiveness of the prevention protocols" be removed from this regulation because the Division does not have purview over funding of related work.

***Response**: NOT ACCEPTED. Proposed subdivision (c)(3) does not dictate how operators obtain or allocate funding. Proposed subdivision (c)(3) requires that an operator evaluate the cost-effectiveness of the possible risk prevention and mitigation protocols identified as part of the operator's RMP. Cost-effectiveness in this context refers to a comparison of the benefit provided by a protocol relative to the expense of the protocol. Understanding the cost-effectiveness of possible prevention and mitigation protocols is an important step for developing an effective RMP. Completion of that step is among the criteria that the Division will examine when evaluating whether an RMP meets the regulatory standard for approval.*

0015-20
§1726.3(c)(5): Commenter suggests the language of this section be revised to "applicable threats" rather than a focus on "each" threat.

***Response**: NOT ACCEPTED. The language suggested by commenter is not consistent with the overall structure of the RMP. Operators must consider each threat that has been identified through the RMP QRA process. Commenter's language suggests that there may be threats that were identified but which do not need to be considered as part of the QRA. It is not the intention of the proposed regulations to require an exhaustive listing of every conceivable threat and hazard as part of an RMP, but the proposed regulations would require, as part of the RMP methodology, prioritization of each and every such risk that is identified..*

0013-6

§1726.3(c)(7): The regulations should establish timeframes for implementation of the prevention and mitigation protocols. Each operator should document their planned time line for addressing and controlling identified hazards in the RMP.

***Response**: NOT ACCEPTED. Each mitigation and prevention protocol will be implemented consistent with the RMP as determined by the QRA process as needed to be effective. Specific timeframes in the regulations would vitiate the responsive, risk-based process of the proposed regulations and could lead to unreasonable delay for protocols that need immediate implementation.*

0013-7

§1726.3(c)(9): "Changed conditions or new information" as parameters for providing updates is vague. The regulations should establish specific triggers or events which would require updates to the RMP, and the timeframe for providing the updates to be enforceable. For example, an RMP update should be required within six months of a significant change to the equipment.

***Response**: NOT ACCEPTED. The "changed conditions or new information "trigger is not vague but rather intentionally broad. Any and all changes in conditions or new information that become known to the operator should trigger a review and assessment of the RMP protocols. However, not every change will require update of the RMP and operators will need to use their judgement, provided that an update is performed at least once every three years. In addition, because an operator must obtain a permit from the Division when it intends to drill new wells or begin a new injection cycle, the Division will use the permit application process to ensure that RMP requirements have been updated as needed. District offices will continue to do regular reviews of projects, generally performed annually, but not less than once every three years.*

0010-2

§1726.3(d): Commenters recommend that the language of the RMP be standardized to require operators to 1) consider the threats and hazards, including provided examples, associated with each aspect of the underground gas storage project, and 2) develop preventative and mitigating measures to address those threats and hazards. Specific text edits recommended include requirements to consider risk and mitigation associated with well design and construction threats, well integrity threats, and threats and hazards associated with well operation and maintenance, monitoring, geologic uncertainty, natural features, well intervention, material balance, third-party damage, reservoir fluid compatibility, and groundwater quality. Commenters would also edit the text to specifically refer to prevention and mitigation “measures” rather than “protocols.”

***Response**: NOT ACCEPTED. The plan already requires the development of mitigating measures once hazards have been evaluated; it is not the goal of the regulations to list every potential risk that may affect each well. Operators must use their judgement as oil field managers to identify and evaluate risks appropriately given the challenges of each specific wellsite and the needs of their operation. The Division will work with operators to ensure that a comprehensive RMP is in place and is regularly updated, but the level of detail proposed by commenters is too prescriptive or otherwise duplicative.*

0002-3

§1726.3(d): Commenter suggests the addition: “if wells are not per 1726.5, then Risk Management Plan must include compliance schedule.”

0005-9

§1726.3(d)(1): Wells that are not in conformance pose a significant health and safety risk. All nonconforming wells should immediately be taken out of use and returned to use only once the operator has shown that conformance has been achieved. Leaving them operating as-is simply cannot be justified given the hazards they pose.

***Response to comments 0002-3, 0005-9**: NOT ACCEPTED. The regulations provide a phased timeframe for operators to bring all wells into compliance. Where a specific well may be a risk to life, health, property, natural resources, or the environment, the Division has the authority to require mitigation measures, shut-in, or plugging as needed. The RMP will be required to identify nonconforming wells and ensure that appropriate protocols are used to address risks associated with these wells; all project wells must be evaluated for hazards with QRA and identified prevention and mitigation measures as part of the RMP no matter their current condition or level of compliance with these standards.*

0013-8

§1726.3(d)(1): It is unreasonable to allow seven years for full compliance and only 10% of nonconforming wells be addressed in the initial year. Maintaining community and worker health and safety must be the priority and the timeframe for full compliance should be reduced and the percentage of nonconforming wells increased. We propose a three-year timeframe for full compliance with 25 percent of nonconforming wells being addressed in the first year, 50 percent in the second year, and the remaining 25 percent in the third year.

***Response**: NOT ACCEPTED. Seven years provides operators with a reasonable time to bring all wells into compliance on a phased basis. Allowing for flexibility prioritization over seven years strikes a necessary balance between promptly achieving full compliance and accounting for the complexity of the needed upgrades and the availability of support equipment, without sacrificing the reliability of the energy system.*

0011-2

§1726.3(d)(1): Commenters are concerned that a seven-year time frame for bringing nonconforming wells into compliance is at odds with the risk-based approach, at least in part because it significantly reduces the ability to address project and well-specific characteristics and manage compliance costs. Unlike the Aliso Canyon well, which was more than 60 years old, commenters operate some of the newest gas storage wells in the state, in some cases wells are less than ten years old. Engaging in extensive well work on such new wells is far riskier in terms of methane release (which is certain during well work) and catastrophic failure than is doing nothing to these wells until corrosion and wall thickness testing indicates a higher level of risk. In addition, requiring these operators to begin to convert nonconforming wells immediately would consume well-work labor and equipment resources for the purpose of modifying the newest, purpose-designed gas storage wells, which are less likely to fail. Those resources would not be available to immediately work on older wells at other facilities, which present a higher level of risk. If the Division adopts a seven-year compliance timeframe, along with a schedule to begin converting wells immediately, commenters recommend that the Division provide operators with some flexibility to schedule work within the seven-year period. Applying the strict percentage requirements proposed, a project with a limited number of wells could be required to meet an accelerated conversion schedule in order to fully comply. To address this issue, commenters recommend that operators of such facilities be allowed the full several years to achieve compliance, with the ability to propose a reasonable schedule for gradually converting wells during that period rather than meeting an annual prescriptive target.

***Response**: ACCEPTED. The language has been modified to allow for 10% of non-conforming wells to be addressed the first year. Subsequently, the total percentage of non-conforming wells which have been addressed must increase by 15% each year.*

0007-1

§1726.3(d)(1): The regulations include the idea that there is a well life expectancy. What about a facility that operates with wells that are over fifty years old? Sixty years? Seventy? Going by this, most of the wells at the Aliso Canyon site should have been retired years ago?

***Response**: NOT ACCEPTED. The proposed regulations require the operator to consider the life expectancy of "Individual mechanical well barrier elements" in recognition of the fact that all mechanical parts have an expected useful life. These well barrier elements can be replaced and/or upgraded as needed; the goal of this requirement is to ensure that the life expectancy of the parts is taken into account when evaluating the risk associated with well design and construction. Thus, an operator who knows that specific well parts are likely to reach the end of their useful life in three years should identify that failure as a risk and then mitigate it, perhaps by increasing inspections of those parts as the three-year period is reached, or proactively replacing parts based on manufacturer's recommendations. A "well" is a hole in the ground that is filled with mechanical elements; after fifty, sixty, or seventy years, much of that equipment will need to be replaced, but the proposed regulations do not suggest that there is a known "well life expectancy" that would justify a blanket retirement requirement.*

0015-21

§1726.3(d)(1): Commenter recommends the requirement "…including specification of the life expectancy of individual mechanical well barrier elements" be removed and replaced with an application of condition-based assessments of integrity validation. Life expectancy can be interpreted as being solely based on age of an asset component rather than condition, thus commenter recommends this be reflected more explicitly.

***Response**: NOT ACCEPTED. The inclusion of information related to life expectancy does not suggest it should be the only factor considered. Reliance on any single factor would be a flawed approach; condition-based assessments should be applied throughout the life of the well. All information that is available and which would contribute to a more accurate assessment of the likelihood of failure and resulting integrity loss should be considered, including life expectancy.*

0002-2

§1726.3(d)(2): Under general design and safety, there must be an absolutely ironclad discussion of the benefits of subsurface shutoff valves.

***Response**: NOT ACCEPTED. The proposed regulations include a requirement for consideration of safety valves based on a list of factors including proximity to sensitive areas. A discussion of the merits of subsurface shutoff valves is more appropriate for a scientific paper, and does not belong in regulatory text.*

0003-2

§1726.3(d)(2): The regulations should specify where surface and sub-surface valves should be installed. For instance, Aliso Canyon should have safety shut off valves at the bottom of every active well or the facility should be shut down.

***Response**: NOT ACCEPTED. A prescriptive requirement for safety valves at specific locations in all wells would ignore site-specific needs and would be less cost-effective. The proposed regulations specify twelve factors which must be considered in an RMP regarding the need for installation of safety valves of various types. The need and appropriate location for safety valves will be determined by the operator based on site-specific characteristics and hazards as assessed under the Division-approved RMP.*

0005-11

§1726.3(d)(2): The criteria listed in this section may be better suited for determining whether a well should exist at all within a certain proximity to populations, or whether a health-based setback in which no gas wells may operate is more appropriate to protect health and safety. This is in line with the CCST's UGS recommendations.

***Response:** NOT ACCEPTED. The criteria in the proposed section are used for determining whether or not the use of a subsurface safety valve is appropriate. The proposed regulations require a RMP for each UGS facility that includes evaluation of threats and hazards associated with operation of the UGS project and identification prevention and mitigation protocols that effectively address those threats and hazards. Consideration of proximity to people is inherent to the RMP process.*

0007-3

§1726.3(d)(2)(A): As for a determination of distance from wells to other buildings, this distance needs to be defined and schools need to be added to this definition. The state needs to work with municipalities and counties to ensure that building permits take this distance into consideration.

Response: *NOT ACCEPTED. The proposed section is focused on the required risk assessment and mitigation protocols of the RMP and does not set any specific standards for distance from other buildings or uses. Instead, the RMP must consider the actual distance to these uses and incorporate the risk of harm to and from these uses into their RMP. The requirement includes "other buildings intended for human occupancy" and "recreational areas, or playgrounds," which would clearly include schools. Like many state agencies, the Department of Conservation routinely coordinates with municipalities, counties, and other local entities to provide information that aids in local land use decisions.*

0015-22
§1726.3(d)(2)(F): Commenter recommends the Division reference where "environmentally or culturally sensitive areas" are defined in other existing regulations/code.

Response: *NOT ACCEPTED. Proximity to environmentally or culturally sensitive areas is one among a holistic suite of criteria for operators to consider when evaluating the need or safety valves as part of the RMP process. Operators should consider uses surrounding each well and identify any areas that could fit into those terms based on common sense. Inclusion of references to specific definitions provided for similar language used in other statutes or regulations would not add clarity.*

0003-3, 0009-2, 0013-9
§1726.3(d)(2)(L): Deletion of active faults is not recommended; the "seismicity" hazard, which remains in the modified text, does not incorporate the fault-displacement hazard posed by the shearing of high-pressure gas storage wells that cross an active, or in some definitions capable fault (capable of generating a damaging earthquake) during an earthquake on the fault. The "seismicity" hazard refers to the threat to well integrity posed by shaking from any nearby earthquake and all of the underground gas storage fields in seismically active California are at risk to that hazard. Aliso Canyon, and probably Honor Rancho, are unique gas storage field settings where all of the wells at the fields cross faults, the Santa Susanna and Honor Rancho faults respectively, that have large total displacements and high late-Quaternary slip rates. The potential threat caused by shearing along these geologically young faults and the uniqueness of the settings will be diminished by deleting "active faults" from the new regulations.

Response: *NOT ACCEPTED. The Division could find no evidence supporting the contention that seismicity is limited to the shaking threat as described by commenter. Instead, seismicity is broadly construed to mean any and all threats associated with earthquake, which would include slip and displacement. Inclusion of active faults was potentially construed by some to eliminate from consideration non-active faults, a definitional distinction that could have eliminated some important risks from consideration. In addition, this subdivision is focused on the issues that must be considered when determining the need for surface and subsurface safety valves, which requires broad consideration of seismic risk rather than focused fault analysis. Later subdivision (d)(11) includes both seismicity and faults as those natural and geologic hazards that must be considered broadly as part of the risk assessment and mitigation for well design and construction, because the presence of faults will affect the geologic conditions regardless of shaking, slip, or displacement. Thus, the consideration of harms of concern to commenters is already included in the regulatory requirements.*

0005-12

§1726.3(d)(3)-(7): The regulations should require and clarify "ongoing" to mean continuous monitoring and/or provide the minimum frequency verification should occur. Additionally, the RMPs should contain requirements for community and worker exposures, including, but not limited to: real-time, continuous air monitoring within facilities, at the fence line, and in nearby communities; rapid deployment of a "network of continuous, reliable, and sensitive indoor and outdoor sensors for high priority chemicals, capable of detecting emissions at levels below thresholds for minimum risk levels;" and, "real-time atmospheric dispersion modeling to provide information about the dispersion and fate of a large release of stored natural gas to the environment."

Response*: NOT ACCEPTED. The requirements for demonstration of well integrity and pressure evaluation of the proposed section are part of the RMP, which requires the operator to use risk assessments based on specific site hazards and well characteristics to determine the appropriate frequency of monitoring and verification. Where "ongoing" is used in reference to monitoring of casing pressures and integrity demonstration, the requirement is not for continuous monitoring, but for regular monitoring based on risk assessment; thus, the frequency will be determined by risk analysis, not regulatory prescription. Section 1726.7 of the proposed regulations includes monitoring requirements applicable to annuli, tubing, pressure within the storage reservoir, gas migration, and unintended gas releases. Monitoring and analyses proposed by commenter, such as atmospheric modeling, are beyond the scope of the proposed regulations.*

0015-6

§1726.3(d)(12): This section requires an assessment of human factors in operators and maintenance procedures which, similar to QRA, is a nascent field still under development in the oil and gas industry, and should not yet be prescribed in regulations. Currently some operators are working towards adapting API RP 1173, Pipeline Safety Management Systems, which brings in human factors; this could be used as a reference, rather than requiring an assessment for which methodologies and tools are still being developed. Commenter agrees that these factors should be included once they are further developed but it is premature to include these specifics at this time and should be considered for future regulation.

Response*: NOT ACCEPTED. The inclusion of requirements for consideration of human factors was recommended by multiple commenters and supported by the National Labs and CCST report. The Division acknowledges that, like QRA, analysis of human factors may be in a nascent stage, and will work with operators to ensure that the process of human factor evaluation does not become an impractical burden. But it must also ensure that human factor risks with high probabilities of occurrence and/or significant consequences are recognized and prevented or mitigated. With that in mind, the Division expects that the proposed regulations will provide incentive for operators to assist in the development of human factor analysis through implementation and lessons learned, and is confident that sufficient understanding of human risks exists to provide value for hazard analysis, prevention, and mitigation, even while the method continues to evolve.*

0013-10

§1726.3(d)(13): Commenter suggests the regulations state the required goals of an effective training program should at a minimum include specific safety and health hazards, emergency operations including shutdown, and safe work practices applicable to the employee’s job tasks. The training program should be implemented consistent with the RMP.

Response*: NOT ACCEPTED. As a required prevention and mitigation protocol under the RMP, the training program will be integrated as part of the overall prevention and mitigation plan. However, the Division’s expertise is not in the development of effective training programs, and will rely on the operators and their experts to create training programs based on their knowledge and experience. Where the Division believes that a proposed training program will not serve the overall goals of RMP implementation to ensure that threats and hazards are effectively mitigated and prevented, it will work with the operator to make improvements such that regulatory goals are achieved, but* *prescriptive requirements for training programs are not appropriate at this stage of regulatory development.*

0010-3

§1726.3(e): Commenters object to the proposed rule in this section which would grant the Division broad authority to waive the preceding risk mitigation requirements. The Division should provide detailed guidelines, including examples, of when variances to the risk mitigation protocols would be appropriate or inappropriate. The proposed broad language invites abuse and threatens to undermine the purpose of the RMPs.

***Response**: NOT ACCEPTED. The proposed regulations are structured to include specific performance criteria and then provide an example of how that criteria may be met. At no time is the Division empowered to "waive" requirements. Instead, any configuration or protocol the operator may propose, which the Division agrees meets the performance standard, is acceptable under the regulations. The goal of this structure is to ensure that minimum protection standards are met, while allowing for new technologies and creative problem-solving by operators. The allowance for these variances does not undermine the RMP, because any variance must be approved as part of the plan and would therefore be incorporated into its risk mitigation protocols. As required by statute, variance is not authorized without written pre-approval from the Division.*

0005-13

§1726.3(f): Commenter is glad the RMPs will be posted on the Division's website. Commenter would encourage the Division to post draft RMPs including their protocols, methodologies, and guidance for public comment prior to approval as well. Risk assessment results, should also be made publicly available on the Division's website.

***Response:** NOT ACCEPTED. The Division wants operators to continually review and update these plans in real-time based on changing site conditions and new information. The goal is to ensure that the RMP focuses on iterative risk assessment, prevention, and mitigation with ongoing adaptation, lessons learned, and technology developed; a public comment process would vitiate this needed flexibility to change and improve. As required by statute, approved RMPs and any supporting information, not specifically determined to be confidential, will be posted on the Division website once approved.*

1726.3.1 EMERGENCY RESPONSE PLAN

0005-19

§1726.3.1(a): Local communities who live within 1 mile of a facility should be provided an opportunity to provide input on Emergency Response Plans (ERPs), in addition to local responders. The operators must also be required to provide these same institutions and residents with access to the plans as well as contact information in case of emergencies, either in written form, online, or both.

Response*: NOT ACCEPTED. ERPs are prepared and implemented by subject matter experts and operator staff who are trained in and knowledgeable about emergency response. This includes local emergency response entities, who have specific expertise in developing good response plans. As required under SB 887, documents and data submitted to the Division pursuant to these proposed regulations, and not determined to be confidential, will be made available to the public via the Division's website.. Local emergency response entities such as police and fire are the appropriate public contacts in the case of any emergency.*

0015-23

§1726.3.1(a): Commenter suggests that submitting the plan is sufficient. Requiring explicit approval from the Division could hinder plan development, updates, and availability, and cause unnecessary delays in implementation and updates to the plan.

Response*: NOT ACCEPTED. The ERP is a required component of the RMP, not a standalone document. Thus, the Division interprets the requirement in PRC section 3181 for approval of the RMP by the Division to include the ERP. Operators should work with the Division to assesses any risks associated with delayed approval and implement interim prevention and mitigation measures as needed.*

0015-25

§1726.3.1(a) and (d): Commenter recommends that providing local first responders with a reasonable opportunity to review, rather than a prescriptive, mandatory time frame, is sufficient.

Response*: NOT ACCEPTED. A timeframe for local review is provided to ensure plans can be completed within a reasonable timeframe. Without a timeframe for local participation, this period could become unreasonably extended. Where a local agency fails to respond within 30 days, the operator is free to move forward with the plan. An operator who believes there is substantial risk associated with a delay for consultation* *on the ERP should contact the Division for approval of interim measures as needed to mitigate any potential harm caused by the review period.*

0008-3, 0015-24

§1726.3.1(a), (c)6), and (c)(8): Commenters recommend the replacement of the term “drills” with “exercises”, which is a consistent term applied with the FEMA Incident Command System. “Exercise” is defined as something performed or practiced in order to develop, improve, or display a specific power or skill and includes but is not limited to drills.

Response*: NOT ACCEPTED. Although the Division is supportive of a broad range of training, including any exercises that will contribute to risk reduction and effective emergency response, the minimum requirement for the ERP is actual drills – in person and onsite. These drills give staff the opportunity to practice emergency response in the actual environment where an emergency may arise, and to identify needed improvements in the response plan. Without these drills, the only time operator personnel may engage with emergency protocols is in an actual emergency, when it may be too late to learn that an important element of the response plan has been omitted. Exercises, which could be limited to classroom or paper activities, are not sufficient to meet this requirement. Operators are encouraged to include a broader suite of activities in their plans if they will lead to more effective emergency response, provided that drills are included.*

0015-26

§1726.3(b)(1): Commenter recommends that the ERP be required to be “consistent with API RP 1171” as well as meeting all the specified requirements in the regulations.

Response*: NOT ACCEPTED. The proposed regulations were developed based on API RP 1171, but are not solely based on those recommendations. Commenter does not appear to identify any specific benefit gained by inclusion of this language, and the Division is generally reluctant to link its regulations to an evolving standard that could change regulatory requirements without Division participation.*

0008-14

§1726.3(b)(1): Commenter suggests deleting this proposed section related to “collisions involving well heads” and replacing with “accidental impacts by moving objects (e.g. farm equipment, cards, trucks, etc.)” to be consistent with API RP 1171.

***Response**: NOT ACCEPTED. Accidental impacts are only one category of risk and would be considered part of the larger category of "collisions." "Collisions" is a broader category that would also include planned or intentional impacts which must also be considered a risk to the wellhead.*

0005-21

§1726.3.1(c)(3): Operators must be required to prepare, implement, and train each employee at the facility in the emergency response protocols, and run at least *annual* safety drills with all employees (not merely provide a schedule for safety drills). Additionally, it should be a requirement that safety drills be witnessed by the Division and Fire Department staff or other first responders.

***Response**: NOT ACCEPTED. The revised requirements for the RMP now include the need for an effective training program with clearly stated goals, which must specify the type and frequency of training to be provided; this would include safety and emergency response training. As part of the RMP, the ERP continues to require a schedule for carrying out drills that address the readiness of personnel and their interaction with equipment, including contractors. Thus, requirements go significantly beyond "a schedule for safety drills." Consistent with the underlying schema of the RMP and the proposed regulations, the actual type and frequency of drills that will be needed must be based on risk assessment. For example, a small operation may be so successful at emergency response that a drill once every two years is sufficient, while a larger operation with higher staff turnover may need a drill once every quarter. A prescriptive requirement for an annual drill could put an operation at risk where more frequent drills are needed based on operational realities. In addition, under the regulations, operators must allow local first responders to initiate drills and may invite them to participate in operator scheduled drills. As evaluating effective emergency response requires technical expertise outside of the Division's scope, a requirement for a Division witness at these drills is not appropriate.*

0008-15

§1726.3.1(b)(4): "Wellhead" should be added in front of "equipment failures" to be consistent with API RP 1171.

***Response**: NOT ACCEPTED. The Division is concerned with all equipment failures and their potential impact on the well, not just wellhead equipment.*

0008-4

§1726.3.1(b)(6) and (c)(5): Commenter seeks to clarify the use of the term “leak” which may be broadly interpreted to be inclusive of non-reportable leaks or fugitive emissions which commenter believes the requirements of this section are not intended to address. Commenter recommends revising “leaks and well failures” to state “reportable releases including leaks and well failures”, and adding “well failures or reportable leaks” to the requirement for prepositioning of equipment, which would provide for consistency with the regulations of CARB, the California Governor’s Office of Emergency Services, and Certified Unified Program Agency, and is necessary to ensure compliance and to avoid enforcement ambiguity.

Response*: NOT ACCEPTED. The proposed section is not focused on reporting requirements, but on those incidents which must be accounted for in the ERP, and is therefore intended to be inclusive of non-reportable leaks and fugitive emissions. Any and every leak and emission must be treated as an emergency, regardless of whether or not the leak is reportable and regardless of how quickly or easily it may be repaired. While the requirements of other agencies are focused on reporting of leaks that are likely to require emergency coordination of multiple agencies based on volume and risk level, the ERP is focused on the required operator response to all leaks and well failures that may occur at their facility. With a clear distinction between reportable releases (limited by regulation and statute) and those releases which must be considered in the ERP (all), there is no enforcement ambiguity.*

0005-20

§1726.3.1(b)(9): It is important that the ERPs include clear outreach and enhanced public information protocols for both leaks that cannot be controlled within 48 hours and emergencies that require a faster response or shelter-in-place orders.

Response*: NOT ACCEPTED. The Division encourages operators to consult with local emergency response entities who have the expertise to ensure these plans are detailed and include responses to all potential scenarios based on specific site-characteristics and known hazards. The public information protocol required by statute will be enhanced by cooperation with these local experts, who will also take the lead in determining the appropriate public notice in case of an emergency affecting area residents. More specific requirements are not needed in the regulatory text to effectuate these activities.*

0015-27

§1726.3.1(c)(6): Drills initiated by others could lead to dangerous conditions for personnel depending on ongoing operations. Commenter strongly recommends against this proposed provision.

***Response**: NOT ACCEPTED. The Division is unclear if commenter was concerned only about surprise drills or about all drills initiated by others. A requirement for surprise drills was removed in this first revision, so that requirement is no longer applicable. However, the Division believes there is no inherent danger in drills initiated by others, provided they are coordinated with the operator, who must provide an opportunity for these drills. This coordination should remove any concerns an operator may have about dangerous conditions, as emergency response personnel can be safely incorporated into the drill and should be trained in the onsite emergency procedures prior to any actual emergency.*

0003-4, 0007-5, 0013-11

§1726.3.1(c)(14): The requirement that a gas company notify the public of a large, uncontrollable gas leak in 48 hours is too long. Commenters suggest requiring the operators to notify the public of an uncontrollable gas leak within one or two hours of discovering the leak or as soon as onsite personnel can safely make release notifications. .

***Response**: NOT ACCEPTED. The language in the proposed section comes from PRC section 3181 and is included here as a required element of the ERP. It is a recognition of the fact that it takes time to evaluate a leak and determine the potential harm and appropriate response. The Division must be notified immediately so that it can assist in this evaluation and ensure appropriate corrective and mitigating actions are taken; other local and state agencies must also be notified. Where the Division, the operator, local emergency response entities, or another state agency determines that the public is at risk, public notification will be made as soon as it can be done responsibly. Statute and the proposed regulations require a notification after 48 hours if the leak cannot be controlled, this does not prevent the response team from releasing information to the public more quickly if needed to protect public health and safety.*

0010-4

§1726.3.1(c)(14): The terms “large” and “uncontrollable” are vague and undefined. If a community may potentially be impacted by a leak, it should be notified as soon as possible, regardless of the size of the leak or the ability of the operator or others to bring the leak under control. The timing for communicating the leak should not be predetermined but rather be based on the potential threats to the impacted community, e.g. the timeframe for communicating a leak of hazardous or toxic material may be different than a leak of materials that do not have environmental or public health threats. Commenters recommend the removal of language including “large, uncontrollable” and “if the leak cannot be controlled within 48 hours of discovery by the operator.”

Response*: NOT ACCEPTED. The language in the proposed section comes from PRC section 3181 and is included here as a statutorily required part of the RMP. It is a recognition of the fact that it takes time to evaluate a leak and determine the potential harm and appropriate response. The Division must be notified immediately so that it can assist in this evaluation and ensure appropriate corrective and mitigating actions are taken; other local and state agencies must also be notified. Where the Division, the operator, local emergency response entities, or another state agency determines that the public is at risk, notification will be made as soon as it can be done responsibly. The proposed regulations require a notification after 48 hours if the leak cannot be controlled, this does not prevent the response team from releasing information to the public more quickly if needed to protect public health and safety.*

0012-2
§1726.3.1(c)(14): On the subject of public notice of large, uncontrollable leaks, we understand that the reference to a 48-hour window in the proposed rule works in concert with other laws and regulations in California that would require a much more rapid public notification. We trust that the Division is working with its counterpart agencies to ensure prompt communication with public in the event of a serious incident.

Response*: ACKNOWLEDGED. The Division is actively working with its sister agencies to improve leak response and hazard management, including working with CARB to implement the recommendations of the CCST report. The Division is confident that the requirement for operators to consult with local emergency response entities on their ERPs will also improve incident response.*

0010-5
§1726.3.1(c)(15): The Division should require operators to estimate the timeframes for deploying necessary personnel and equipment. This analysis may reveal important gaps in the availability of local personnel and equipment, and is also important information to communicate to any nearby residents and first responders.

Response*: NOT ACCEPTED. Operators will do this as a part of their ERP development when making determinations regarding the appropriate prepositioning of equipment and* *personnel as required by the proposed regulations. These timeframes may change depending on circumstances such as time of day, traffic, or weather. Operators will also learn about the effect of these variables during their emergency response drills and will be able to adjust based on actual conditions rather than relying solely on preliminary estimates. The operators are responsible for the effectiveness of implementing their ERP; a more specific requirement is not needed.*

0008-5
§1726.3.1(d): Changes in key individual personnel should not trigger the need to review and update the ERP, as emergency response roles are typically staffed according to the position with the requisite expertise. Rather, changes in process should trigger a review and update to ERP.

Response*: NOT ACCEPTED. At the time of a change in key personnel, the operator must review the ERP to determine if the change necessitates update. If the operator determines that no update is needed, then no update is required, and the operator must simply retain evidence to support that decision, such as a documentation of the training and experience of the new staff member. With that in mind however, it is highly unlikely that changes in key personnel will not require at least an update to the drill schedule such that new staff can be incorporated into the facility's process. For example, someone with extensive expertise in emergency response at facilities in Texas may not be familiar with some of the challenges posed by California topography and regulation, and is unfamiliar to onsite staff who may not respond in the same way to new leadership. In addition, "key personnel" may include onsite staff whose primary role is operations and NOT emergency response, but who still play a key role in emergency situations due to their operational role at the facility.*

0010-6
§1726.3.1(d): Key personnel changes are not the only change that should trigger a review of the ERP. Changes in the way a gas storage project is operated or monitored could also necessitate a change. Moreover, the LA County Fire Department has indicated that the accepted standard for updating ERPs is annually.

0013-12
§1726.13(d): Health and Safety Code, Chapter 6.95, Article 1, Section 25508.1, requires updates within 30 days to a facility business plan for specific changes, including a "substantial change," defined therein as any change in a facility that would inhibit immediate response during an emergency by either site personnel or emergency response personnel, or that could inhibit the handler's ability to comply with Section

25507, change the operational knowledge of the facility, or impede implementation of the business plan. As an example, if there are changes to the facility primary or secondary emergency contacts, the business plan must be updated in the statewide information management system within 30 days. Additionally, Section 25508 requires an annual electronic submittal and certification of the business plan, which includes ERPs and procedures. Therefore the ERP must be reviewed on an annual basis to certify its accuracy to ensure personnel can respond safely and appropriately to unplanned or uncontrolled emergencies.

0012-4

§1726.3.1(d): Commenters commend the Division for making significant advances in the ERP section of the proposed regulation, including adding a requirement for ERPs to be updated regularly. However, the three-year cycle that the Division has proposed is far too long. Annual updates of ERPs are common practice throughout Los Angeles County, and rightly so given the rate of change in operational practices, civilian population and infrastructure, on-site and off-site company personnel, and communication methodologies. The Division should require annual updates, which should include revisions to the plan incorporating among other things, lessons learned from drills and exercises. Less frequent reviews will likely lead to stale plans and inappropriate emergency response that could potentially cause significant risk to the public and the environment.

Response to comments 0010-6, 0013-12, 0012-4*: NOT ACCEPTED. The ERP is a required protocol of the RMP and must be reviewed whenever the RMP is reviewed. The proposed regulations require the RMP to be reviewed and updated "no less than once every three years and in response to changed conditions or new information." Thus, the ERP must be reviewed when there are key personnel changes, and when a changed condition or new information would affect emergency scenarios and/or planned response. Annual review is not appropriate for fields in non-urban areas where conditions do not change frequently enough to justify the commenter-suggested review frequency. Where an operator and local emergency response officials in an urban area believe that more frequent review of the ERP is required to effectively mitigate risk, the RMP and ERP can implement a alternative review period.*

0010-7

§1726.3.1(e): It is critical that the Division be notified as soon as possible when a potential emergency is discovered. It is also critical that this information be shared with the public as soon as possible, especially any members of the public that may be impacted by that emergency. Commenters recommend the addition of language to this section requiring notification to the Division as soon as possible, but no later than 24 hours following the discovery of an emergency and requiring the Division to post a notice of emergency on its website with facility emergency 24-hour contacts, including phone numbers and e-mail addresses for lead personnel.

***Response**: NOT ACCEPTED. The proposed regulations already require the Division to be notified immediately in the case of a leak so that the Division can participate in the appropriate emergency response. In the case of other emergencies, Division participation may not be needed. For example, a vehicle fire would be covered under the ERP and would be considered an "emergency" but there is no value to notice to the Division unless there is a collision with or damage to a well. An employee injury would similarly be an "emergency" for which there is no benefit to Division notice or participation. The plan requires, as dictated by statute, a protocol for public notice of a large uncontrollable leak which would likely include the posting of some information on the Division website, but 24 hours is too short a timeframe. Local emergency response entities may still determine that public notice is needed for health and safety more quickly, but in most cases an operator will need time to assess and respond to the emergency. Posting contact information for lead personnel on the internet would inhibit the regulatory goal of effective emergency response; personnel need to remain focused on emergency response and cannot be tasked with responding to public phone calls and concerns. In any incident, local emergency response entities will determine appropriate public notice and will provide contact information for informational personnel who are prepared to field public inquiries. An "emergency" is a broad category that requires significantly varied response; a strict requirement for Division involvement and public notice for every incident is not needed.*

1726.4 UNDERGROUND GAS STORAGE (UGS) PROJECT DATA REQUIREMENTS

0002-4
§1726.4: Deleted section 1724.9(c) addresses preparing and submitting a "list of proposed surface and subsurface safety devices, test, and precautions taken to ensure safety of the project." If there are to be such devices according to requirements, then such a list relating to safety is critical to the commitment to include these devices. It is not redundant.

***Response**: NOT ACCEPTED. Section 1724.9 is an existing code section that is being deleted in its entirety and replaced by a new Article 4 with sixteen code sections. This new article expands significantly upon the limited requirements of section 1724.9. A* *requirement for a list of devices, tests, and precautions that will be used to ensure the safety of the project is included under proposed section 1726.4(a)(2).*

0004-4, 0015-10

§1726.4: The data requirements in this section should only be applicable to new underground gas storage projects, as several of the data requirements would be impractical or impossible to obtain for existing storage projects. If this section is applied to existing projects and wells, then commenters suggest text modifications for clarification.

Response*: NOT ACCEPTED. The purpose of SB 887 was to ensure that all UGS projects, existing and new, are subjected to the heightened level of risk management, construction standards, and testing requirements of the proposed regulations. Where it may be difficult for operators to provide a specific data type, the proposed regulations allow an application for variance to the Division for data that will otherwise meet the performance standards. Language such as "proposed" has been removed to clarify that requirements apply to all projects and all wells within all projects, both new and existing.*

0005-22

§1726.4: Where well stimulation or enhanced oil recovery has occurred, or will occur, at a gas storage project or a well in the AOR, there should be extra requirements for monitoring to detect loss of integrity. These should, at a minimum, reflect the API Handbook's list of monitoring practices associated with well stimulation.

Response*: NOT ACCEPTED. Monitoring for integrity loss is already required, including a real-time monitoring system and regular integrity testing. Hazards associated with operational activities must be assessed and mitigated as part of the RMP. Where a well in the AOR will be performing well stimulation or enhanced oil recovery activities not associated with gas storage operations, it will be subject to the regulations of the existing well stimulation regulatory program.*

0005-23

§1726.4: The Division must publicly provide information on all well stimulation activities that have occurred and are occurring at gas storage facilities, including hydraulic fracturing. Well stimulation poses excessive risks to well integrity, geologic integrity, and water, and the public is entitled to full disclosure of these dangers.

Response*: NOT ACCEPTED. The Legislature specifically exempted gas storage well stimulation activities from the notice and public disclosure requirements of SB 4.*

However, under existing regulatory section 1777.4, UGS operators must already report all well treatments, including acid and pressure treatments, to the Division within 60 days of completion. The information provided is maintained in the database of well information which is available via the Division's website, unless the information has been specifically determined to be confidential. Thus, a requirement for additional disclosure in the proposed regulations is not needed.

0012-5
§1726.4(a)(X): Commenter suggests the following addition: Proposed methods for demonstration of external and internal mechanical integrity of any existing wells to be converted to underground gas storage.

Response*: NOT ACCEPTED. Proposed methods for demonstration of integrity of all wells, converted or otherwise, are included as part of the RMP. An additional requirement under the data section would be duplicative and would suggest that the proposed methods are a fixed data point, when they are instead a plan that must be continuously evaluated and updated for effectiveness in the prevention and mitigation of risk.*

0010-8
§1726.4(a)(4)(A): Commenters support the proposed revision that the injection pressure not exceed the fracture pressure of the reservoir or confining strata but recommend that a safety factor, like that of Kansas, be incorporated (See K.A.R. §82-3-1003(b)(6)). Text should be modified to limit injection pressure to a maximum of 75% of the fracture pressure as determined by a step rate test, with a specific prohibition against operating pressures in excess of the calculated fracture pressure even for short periods of time.

Response*: NOT ACCEPTED. The calculation of maximum operating pressures is done on a well-by-well basis, approved by the Division, and incorporated into the protocols of the RMP. The Division uses multiple measures to calculate this pressure, including historical data and step rate tests, and approves the maximum operating pressure for each well based on the real conditions on the ground. Thus, the risk associated with excessive pressure is already accounted for in the approval process. In addition, underground gas storage operators have a greater incentive to protect a reservoir from fracturing than in most oil extraction operations. This is because any "fracturing" or expansion of the reservoir could lead to new channels of fluid migration, violating the reservoir containment performance standards that form the core of the proposed regulations, greatly increasing the risk of liability for operators, and potentially leading to* *loss of product. Thus, a specific requirement designed to avoid dangers associated with fracturing of the reservoir is unnecessary in UGS operations.*

0008-16

§1726.4(a)(5)(C): Commenter recommends clarifying "reservoir fluids" to "natural reservoir fluids," where "natural reservoir fluids" would encompass such fluids as oil, gas, and water, and would clarify the exclusion of drilling fluids injected into the reservoir, which are regulated by section 1722.6.

***Response**: NOT ACCEPTED. This proposed section is focused on the requirements for a comprehensive geologic characterization of the project as part of an engineering and geological study. As such, it must include any information that may be required to ensure that any and all fluids, which are present in or may be injected into the reservoir, will not have an adverse effect on the project or the protected categories of life, health, property, natural resources, and the environment. This includes kill fluids, drilling fluids, cleaning fluids, accidentally introduced fluids, fluids already present in the reservoir, and any other fluid that could potentially migrate or become entrapped in the reservoir and surrounding formation. Thus, limiting of required fluids for consideration to only natural reservoir fluids is not consistent with the purpose of this requirement. In contrast, section 1722.6 sets standards for operational procedures and the properties, use, and testing of drilling fluid; it does not require information needed to evaluate how drilling fluid interacts with the geology of the reservoir and cannot be considered an appropriate substitute for the requirements of this proposed section.*

0010-9

§1726.4(a)(5)(C): It is important that maps prepared in support of geologic characterization show all relevant features that may interfere with or enhance containment of stored gas, so that the Division and the public have access to complete and accurate information when assessing the adequacy of the geologic system. Commenters recommend detailed additions to this section including maps of faults and other lateral containment features including at the base and top of the caprock, and the base of the lowermost USDW, four structural dip and strike cross sections extending across the AOR, four stratigraphic cross sections through at least four gas storage wells, porosity and permeability of the caprock and confining zones, and geomechanical properties of the storage reservoir and caprock.

***Response**: NOT ACCEPTED. The term "caprock" is no longer used in these proposed regulations and has been replaced with "confining strata," which expands the maps requirement to include all the areas of concern to commenters. Faults and lateral* *containment features are already included; additional data subdivisions recommended by commenters are already included or are not needed for the Division's regulatory purposes.*

0012-6

§1726.4(a)(5)(C): Commenters recommend that the geologic characterization be required to include "…identification of groundwater, flow zones, lost circulation zones, or other commercial hydrocarbon-producing zones…"

Response*: NOT ACCEPTED. The purpose of the geologic characterization requirements is to ensure that the geology of the reservoir has been evaluated for potential pathways of fluid migration and entrapment of migrated fluid. Identification of groundwater is already required under subdivision (a)(5)(C)(iv), flow zones and lost circulation zones are engineering concerns that do not relate to reservoir integrity, and other commercial hydrocarbon-producing zones will already be known to the Division or otherwise identified as part of the requirement to identify subsurface activities in the AOR. Commenter's recommended requirements are not needed in the proposed section.*

0012-7

§1726.4(a)(5)(C)(iii): Commenters recommend that the geologic cross sections be required to provide "…sufficient geological information to accurately characterize vertical and lateral structural and stratigraphic relationships within the project and immediately adjacent areas."

Response*: NOT ACCEPTED. The comprehensive geologic characterization that is required under subdivision (a)(5)(C) includes a requirement for the lithology of the storage zone or zones and sealing mechanism as well as all formations encountered. This broad requirement applies to all subdivisions of (a)(5)(C), including (iii). Thus, commenters' requirement is already incorporated into the performance standard for the geologic characterization; a duplicate requirement in this subdivision is unnecessary.*

0012-8

1726.4(a)(5)(C)(v): Commenters recommend including isoGOR and isoBAR on this list and requiring that three-dimensional modeling include seismic modeling.

Response*: NOT ACCEPTED. The Division does not believe that either an isoGOR or an isoBAR are useful for its regulatory needs. An isoGOR, which shows gas-oil ratios in a field, may be useful for many purposes, but is unlikely to inform a geologic* *characterization focused on migration pathways. Similarly, an isoBAR, which is a map that shows points of similar pressure in a field, is not useful when that field pressure will be affected and changed by ongoing operations. Thus, although an operator may use both of these tools for evaluating economic viability, they do not appear to provide any information consistent with the regulatory purposes of this subdivision. Also, in many cases, seismic modeling is unavailable, and/or is otherwise proprietary to the operator. Although the Division could require the operator to provide raw data used to build seismic models, it does not have the resources to produce these models itself, making this requirement unnecessary to meet Division regulatory goals.*

0005-25

§1726.4(a)(5)(D): Mere reporting of "water quality" under this section is inadequate. Operators should be required to submit a detailed numerical groundwater model to ensure water quality is adequately protected.

Response*: NOT ACCEPTED. The proposed regulation already would require the operator to demonstrate that the UGS project will not cause damage to life, health, property, natural resources and the environment, and proposed subdivision (a)(5)(C)(iv) requires data regarding groundwater quality in the gas storage zone. If the Division is unsatisfied with the water quality information provided by the operator, it will request additional data.*

0010-10

§1726.4(a)(5)(D): To protect actual and potential sources of drinking water, gas storage should not be allowed in zones that meet the federal definition of an Underground Source of Drinking Water (USDW). Commenters recommend the addition of "including but not limited to TDS," to the requirement for reservoir fluid data on water quality and to include language specifically prohibiting storage in zones containing USDWs.

Response*: NOT ACCEPTED. The Division requires the operator to show that the UGS project will not cause damage to life, health, property, natural resources, and the environment. Contamination of USDW would violate federal law and would be damage to a natural resource and the environment under state law, making a specific prohibition in the proposed regulations unnecessary. If the Division is unsatisfied with the water quality information provided by the operator, it will request additional data.*

0010-11

§1726.4(a)(5)(E): Special steps must be taken to ensure that all wells in a gas storage field have been identified. Given California's long history of oil and gas production, locating existing wells – in particular plugged and abandoned wells – may be challenging and require the use of multiple detection methods. Failure to identify orphaned or improperly constructed or abandoned wells can result in leakage. For example, improperly abandoned wells at the Montebello UGS facility in Los Angeles leaked natural gas to the surface, resulting in the facility eventually having to be decommissioned, but not before homes had to be abandoned and torn down in attempts to repair the leaking wells. Commenters recommend the addition of language to require operators to "develop, submit and implement a plan to identify all wells within and adjacent to the" AOR. The plan must include four stages of investigation: Historical Record Review, Site Reconnaissance, Aerial and Satellite Imagery Review, and Geophysical and Air Emissions Surveys.

***Response**: NOT ACCEPTED. Requiring operators to develop a plan to meet the requirements of commenters' proposed additions is too prescriptive and unnecessary to achieve the Division's regulatory goal of producing a map that shows the location and status of all wells within and adjacent to the AOR. Allowing the operator to decide how to produce the map ensures that operators are meeting a minimum regulatory standard without imposing a prescriptive plan.*

0003-5
§1726.4(a)(5)(F): Why did you delete some requirements for casing diagrams, i.e., "gas migration?"

***Response**: NOT ACCEPTED. Some of the language from the proposed section was deleted for being duplicative, while other language has been moved. Thus, no requirements have actually been deleted. This subdivision was re-written in recognition of the fact that it confused the performance standard for well construction and integrity ("not a conduit for gas migration…") with the requirement for a graphical representation of actual well configuration. The requirement that the data submitted demonstrate that stored gas will be confined to the approved zone and not cause damage, appears in subdivision (a), and applies to all the data which must be submitted including the graphical casing diagrams or flat file data sets. The language related to plugged and abandoned wells was moved to new proposed subdivision 1726.4.2(a)(2).*

0008-17, 0015-28
§1726.4(a)(5)(I): Commenters observes that the term "unit boundaries" is undefined and ambiguous and interprets the intention of this statement to refer to the project's boundaries. The text should be revised to refer to "it's boundaries" or the "underground gas storage project boundaries."

***Response**: ACCEPTED. The text has been revised to refer to the "underground gas storage project boundaries."*

0005-27

§1726.4(a)(5)(J): It is essential that this section require operators to provide maps of all "injection wells and zones, mining and other subsurface industrial activities not associated with oil and gas production or gas storage operations within the" AOR regardless of whether it is "publicly available." These are essential safety considerations and must not be omitted merely because the information is not currently in the public domain.

***Response**: NOT ACCEPTED. Where industrial activities do not fall under the jurisdiction of the Division, the proposed regulations cannot require disclosure of proprietary information, and it is unlikely that such specific information would be necessary. As this requirement is limited to maps of locations and does not require additional detail regarding the operations themselves, it is likely that the majority of information needed will be in the public domain via local permitting or state regulatory agencies.*

0008-18

§1726.4(a)(6)(A): Commenter suggests revising "maximum anticipated daily rate" with "maximum anticipated <u>average</u> daily rate," as it's not always possible to determine a maximum anticipated daily rate without detailed well test data.

***Response**: NOT ACCEPTED. The Division is not interested in an estimated average for a maximum daily rate, which would be the result of commenter's proposed change. Instead, the goal is to set a maximum anticipated rate that will be the upper boundary of activity on a daily basis as part of the "gas storage injection and withdrawal plan." For example, if during some months the planned daily rate of injection is X, while in other months the planned daily rate is X+Y, with an emergency or high-need rate of X+Y+Z, then the plan should include the maximum anticipated daily rate of injection at X+Y+Z, because that is the maximum that is ever anticipated under the plan. An average is not consistent with the regulatory purpose of the proposed section.*

0012-9

§1726.4(a)(6)(A): Commenters recommend requiring withdrawal pressures and maximum anticipated daily rate of withdrawal as part of the gas storage injection and withdrawal plan.

***Response**: NOT ACCEPTED. The purpose of this requirement is to ensure that activities under pressure are conducted safely based on reservoir capacity and well integrity risk. Because withdrawal does not add pressure to the reservoir but relieves it, there is no regulatory need to set maximum pressures and rates for withdrawal.*

0008-19
§1726.4(a)(6)(E): Commenter suggests revising "analysis" to "a representative gas sample analysis," which accounts for variation in supply throughout the year.

***Response**: NOT ACCEPTED. An annual requirement to submit an analysis of gas injected is by necessity an analysis of a representative sample, as it would be impossible to test every molecule of gas injected during every injection cycle. The injection and withdrawal plan required under the proposed section requires an initial analysis of gas to be injected, with an updated analysis annually or anytime the gas mixture to be injected is changed. Specification that the sample be representative is not needed.*

0005-24, 0010-14
§1726.4(d): This proposed provision gives the Division extremely broad discretion to waive any and all of the preceding requirements of this section simply on the basis of "infeasibility" – a term that is not defined or limited in any way. The data and information required are both critical to ensure well safety and feasible to provide. There should be no reason to accept less, as is permitted by this section. If it is necessary to provide an alternative form of data reporting, this subdivision should establish a process of public notice and comment on the proposed alternative form, or alternatively, the project should not be approved.

***Response:** NOT ACCEPTED. The purpose of the data requirements in the proposed section is to provide a complete file for evidence-based decision making; the specific data types or requirements are less important than the ability to gain a comprehensive picture of the conditions and challenges surrounding the wells and the project. As such, where an operator can demonstrate that an alternative piece of data provides the same information or otherwise informs the scientific analysis, the Division has the flexibility to accept that alternative data; a full waiver of the requirement is never acceptable. As this is a scientific evaluation of data quality equivalence, it is not an appropriate subject for public comment.*

0012-10

§1726.4(f): Commenters recommend the addition of language indicating that records will be subject to confidential treatment "…per the California Public Records Act of relevant federal law…"

Response: *NOT ACCEPTED. There are multiple sources of law which cover confidential treatment of records including the Public Records Act, trade secret protections, HIPAA, and others. Because there are many confidentiality provisions that are subject to change, the Division cannot limit its confidentiality analysis to statutes or requirements currently in existence or otherwise specified. Records will be subject to confidential treatment in all cases where there is a legal requirement to provide such protection.*

0008-6, 0011-3, 0015-11

§1726.4(g): Given the potential scope of this requirement, in addition to the other regulatory requirements, (such as submitting the revised RMP to the Division and compliance with PHMSA), which will require significant effort during this same time period, commenters request that the deadline for submission of revised and updated project data be aligned with the submission requirement for the RMP at six months (180 days).

Response: *ACCEPTED. The language has been revised to allow 180 days for compliance with the data requirements of the proposed section.*

1726.4.1 CASING DIAGRAMS

0010-15

§1726.4.1: Commenters support the proposed requirements for casing diagrams and recommend that the following also be included: date idled.

Response*: NOT ACCEPTED. The addition of "date idled" would not be appropriate for inclusion on a casing diagram as it is not a permanent condition.*

0012-11

§1726.4.1(a)(1)(J): Commenters recommend the addition of "open-hole completions" and features that may compromise "the ability to fully access the wellbore to total depth."

***Response**: NOT ACCEPTED. Open hole completions are not permitted in UGS wells due to minimum casing and integrity requirements. The Division does not have a need to access the wellbore to total depth; there may be instances where junk is stuck in the hole and the full depth cannot be accessed, which must be managed, but the Division is unaware of any specific risk or concern that would justify the need for this requirement.*

0012-12
§1726.4.1(a)(3): Commenters recommend that "bottomhole" locations also be required.

***Response**: ACCEPTED. The language has been changed to include "bottomhole" locations as well.*

0015-29
§1726.4.1(b): Commenter believes the section reference to 1724.6 is in error and instead should actually be 1726.4.

***Response**: ACCEPTED. The reference has been corrected. Thank you for catching the error.*

1726.4.2 EVALUATION OF WELLS WITHIN THE AREA OF REVIEW

0012-13
§1726.4.2(a)(2): Commenters recommend that plugged and abandoned wells be required to have "competent" cement in all described locations.

***Response**: NOT ACCEPTED. A requirement for cement to be used for a specific purpose inherently requires that the cement be sufficient to meet that purpose. Thus, a specific modifier that requires cement to be "competent" assumes that without such modifier non-competent cement is acceptable, which it is not. Supporting this interpretation, a review of existing statute and regulation affecting Division activities provides not a single example of a specific standard for cement quality. Instead, cementing standards are performance based, and the cement used must be sufficient to meet the performance standard, which requires that the cement "ensure that wells within the area of review will not be a potential conduit for fluid migration." Where cement is not competent to meet this standard, it will not be accepted, but "competency" in itself is not the standard and should not be included here.*

0010-16

§1726.4.2(a)(2): Commenters object to the proposed requirements as being insufficient to ensure that plugged and abandoned wells will not act as potential conduits for fluids to migrate outside of the approved gas storage zone. The proposed regulations also fail to include steps that must be taken in case of plugged and abandoned wells don't meet the requirements. Commenters recommend that the final sentence of this subdivision be struck and replaced with language outlining detailed requirements for plugging and abandonment. It is critical that these requirements be updated.

Response*: NOT ACCEPTED. Gas storage wells remain subject to the plugging and abandonment requirements of regulatory sections 1723-1723.9 which include detailed instructions for cement plugs by zone depending on well configuration as recommended by commenters. Where wells do not meet the requirements, the operator must demonstrate that the well will not serve as a fluid migration conduit, or the Division is empowered to require re-entry and re-abandonment.*

0005-28

§1726.4.2(a)(3): The Division should specify the exact conditions under which it would approve an "alternative demonstration that the well will not be a potential conduit for fluid migration outside the approved gas storage zone."

Response: *NOT ACCEPTED. An alternative demonstration will be required if a plugged and abandoned well is not cemented to the proposed specifications. The standard is one of performance – the demonstration must indicate that the well will not be a potential conduit. This could be demonstrated by showing an alternative cementing configuration which is sufficient to prevent fluid migration or other conditions which make fluid migration impossible, such as the geologic conditions surrounding the well. As the Division is willing to accept any demonstration which meets the performance standard, exact conditions cannot be delineated.*

0015-30

§1726.4.2(a)(3): Commenter recommends including an example of an alternative demonstration that would be acceptable such as "…for example through a RMP for plugged and abandoned wells…"

Response: *NOT ACCEPTED. The Division is unwilling to include any specific example that might lead an operator to believe their demonstration will automatically be accepted. Instead, an operator must demonstrate that a plugged and abandoned well will not be a conduit for fluid migration using whatever means actually achieve that* *standard. An RMP for plugging and abandoned wells would only be sufficient if the provisions of that RMP prevent fluid migration. Unlike the RMP mitigation protocols, minimization of risk is not sufficient in the context of plugged and abandoned wells.*

0008-20

§1726.4.2(a)(3): Commenter believes the Division intends to allow for both the singular and plural form of "basis(es)" in this section.

Response: *ACCEPTED IN PART. The Division has modified the language of the proposed section to change "bases" to "basis". Thus, the "basis" of the Division's decision must be documented. The term "basis" is singular, but encompasses the collective whole of evidence used to support the Division's finding, which may include multiple data items and analyses. Commenter's concern about singular and plural term use should be resolved by this change.*

1726.4.3 RECORDS MANAGEMENT

0010-17

§1726.4.3: Commenters support proposed requirements for operators to develop a Records Management Plan but object to the Division's proposal to strike the language that the plan should be reviewed and approved by the Division. As noted in the Initial Statement of Reasons, appropriately managing records is crucial to the safe operation and rigorous oversight of underground gas storage projects. As such, the Division should retain its authority to ensure that each operator's Records Management Plan is adequate and that any revisions are made as necessary.

Response: *NOT ACCEPTED. The proposed regulation has been revised and the express requirement for review and approval of the records management plan has been removed, but the proposed regulation still results in records management requirements enforceable by the Division. Under the proposed regulation, an operator must establish and submit to the Division a records management plan that accomplishes various minimum requirements. The Division will then hold the operator responsible for meeting the minimum regulatory requirements in the manner described by the plan. This does not negate the operator's responsibility to manage the records management plan as it may impact operations, but provides the Division with the ability to ensure that the operator meets a minimum regulatory standard without imposing a prescriptive plan.*

1726.5 WELL CONSTRUCTION REQUIREMENTS

0005-30

§1726.5: The Division should require that operators immediately cease all injection, and conduct a thorough investigation of the integrity of all gas storage wells in the state. Any wells with a single barrier and no safety valve must immediately be pressure isolated from the underground storage aquifer and undergo inspection using best available technology to search for evidence of corrosion, cracking, or other loss of integrity. If any such evidence is found, the well must be taken out of operation immediately, and reworked to add cement casing. If the well does not have a subsurface functioning safety valve, it must immediately be plugged to the base.

***Response**: NOT ACCEPTED. While the Division does have the authority to impose remedial requirements as needed to prevent damage to life, health, property, and natural resources, that does not extend to banning all injection at all locations. Under the proposed regulations, operators will be required to thoroughly test and inspect each gas storage well, to conform to rigorous new construction requirements for gas storage wells, and prepare a detailed risk management plan for each underground gas storage facility. Existing wells that are not in compliance with the new construction standards will be corrected over time based on level of risk, in accordance with a work plan approved by the Division as part of the operator's RMP. Availability of equipment and personnel make a single deadline requirement for all wells to meet the new well construction standards unreasonable and impracticable to implement.*

0005-33

§1726.5: All wellheads should also include a pressure observation valve on the tubing, the packer, and each annulus of the well.

***Response**: NOT ACCEPTED. This would be an acceptable well configuration but is not a required well configuration. Operators must determine the appropriate well configuration to meet the performance standards based on their risk assessments and site-specific hazard evaluation.*

0005-32

§1726.5: All wells should be required to have a functioning and installed leak and fire detection system, integrated with a warning system.

***Response**: NOT ACCEPTED. Where risk assessment for a specific well determines that an installed leak and fire detection system with an integrated warning system is* *appropriate to ensure well integrity, the operator may obtain Division approval to use it as part of its RMP protocols. The Division has provided performance standards for well configuration that may be met by any method which provides for two mechanical barriers and regular integrity verification.*

0011-4

§1726.5(a): As drafted, this section might be construed as applying to plugged and abandoned wells that penetrate gas storage reservoirs. Standards applicable to these wells are set forth in section 1726.4.2. Accordingly, commenters recommend that this section be revised to explicitly clarify that it does not apply to wells that have been properly plugged and abandoned under 1726.4.2(a)(2) and (3).

***Response**: ACCEPTED. Language has been added to the section to explicitly clarify that wells which have been plugged and abandoned in accordance with PRC section 3208, are not subject to the well construction requirements as outlined in the proposed section.*

0014-1, 0015-31

§1726.5(b)(1): There are two references to section 1726.6(a)(1) regarding pressure testing of the primary and secondary mechanical barriers. Commenters believe the reference should instead be to 1726.6(a)(3), which discusses pressure testing. 1726.6(a)(1) refers to noise/temperature logging.

***Response**: ACCEPTED. The reference has been corrected. Thank you for catching the error.*

0005-31

§1726.5(b)(1)-(7): Storage well leaks and disasters occur under unexpected conditions; wells should be constructed not only to withstand expected conditions but also unexpected conditions. Subdivision (b)(5) recognizes the importance of design to withstand excessive loads for case connections, but this design capacity needs to be extended to all aspects of the storage well. In subdivisions (b)(1), (2), (4), and (7), the regulations should require that storage well components be designed to withstand *greater than expected* conditions.

0010-18

§1726.5(b)(4): Commenters request that an appropriate safety factor be incorporated into well material selection and design to ensure that wells will maintain integrity in the event of an upset, accident, or other malfunction, and as such recommend the following addition: “plus an appropriate safety factor.”

Response to comments 0005-31, 0010-18*: NOT ACCEPTED. Pressure testing and casing wall thickness inspections are already conducted at 115% of maximum allowable operating/injection pressure, providing for a safety factor that must be incorporated into the design to ensure successful testing of well integrity. Industry standards generally require a well to be built to sustain integrity based on reservoir pressure, rather than operating pressure, which is always lesser. Thus, the design process inherently includes a safety factor which does not need to be specified in the regulations.*

0005-34
§1726.5(b)(2): Commenter suggests that the regulations specify minimum requirements for overlapping casing strings, such as 200-feet of overlap. As they stand now, they are vague.

Response*: NOT ACCEPTED. Cementing requirements are outlined in existing regulations section 1722.4 and do not need to be duplicated in the proposed regulations.*

0011-6
§1726.5(b)(6): For clarification, commenters recommend that this section be revised to require cementing of the well by providing isolation from communication with ~~of~~ fluids from other zones of interest~~ is prevented~~.”

Response*: ACCEPTED. The language of the proposed section has been revised as recommended.*

0008-8
§1726.5(b)(7) and (c): Commenter cautions that the requirements of section (b)(7) as it applies to existing wells may require perforating the production casing, thereby having the potential to compromise the secondary barrier. Commenter interprets that this is not the intent of this section, and believes it would be appropriate to address such instances with the subsequent provisions in subdivision (c). Commenter requests the Division clarify in such instances what the operator would be required to provide in order to demonstrate that such an alternative method of well design and construction meets the performance standard in subdivision (a). Alternatively, commenter proposes that cementing operations requirements in the second sentence of (b)(7) be applicable to new wells only.

***Response**: NOT ACCEPTED. Commenter is correct that operators who believe the default well configuration may cause a hazard in the context of an individual well, should use section (c) to request approval of an alternative well design. This is particularly encouraged where design evolution and technology development indicate that there may be more effective configurations. However, if the Division were to provide a list of those data and analyses which must be provided, potential viable configurations might be eliminated, removing any opportunity for the creative design and innovation that could actually lead to better protections. Thus, the alternative demonstration section is broadly written to ensure that operators can use any and all available technology and data to meet the performance standard in subdivision (a). Operators proposing an alternative configuration should focus on data and analyses that support their finding that it will be effective at meeting this performance standard, rather than relying on the Division to identify those items that could provide such evidentiary support.*

0010-19
§1726.5(b)(7)(B): The Division's existing cementing rules at 1722.4 are inadequate to protect groundwater that meets the federal definition of a USDW. Commenters recommend that this subdivision be revised to require that intermediate casing be cemented to the surface, unless set for a reason other than to isolate protected groundwater, in which case it should be fully cemented to surface unless doing so would result in lost circulation. If not cemented to the surface, the casing should be cemented to fill the annular space from the casing shoe to at least 600 feet above fluid-bearing formations, lost circulation zones, oil and gas zones, anomalous pressure intervals, or other drilling hazards. Multi-stage cementing must be required if this is technically infeasible.

***Response**: NOT ACCEPTED. The cementing requirements in existing regulation apply across Division programs and are targeted for update within the next few years. In the meantime, any concerns regarding the ability of wells to maintain integrity will be managed as part of the RMP. In addition, commenters' proposed requirements are excessive without clear regulatory benefit; 600 feet of cement far exceeds any similar requirement in the known regulations and the Division is unaware of any scientific data which would support such a large change in cementing standards. Operators will determine the appropriate cementing based on site-specific risk assessment for each well as part of the RMP. Provided that the Division approves their plan, no additional cementing requirements are needed. Multi-stage cementing may be appropriate if indicated by risk assessment, but it is not required.*

0010-20

§1726.5(b)(11): Only advanced cement evaluation logs should be accepted to demonstrate cement integrity and any cement evaluation log used by the Division should be representative of current well conditions. Commenters recommend revisions requiring cement evaluation submissions to be no more than two years old.

Response*: NOT ACCEPTED. The bond log or evaluation required by the proposed section is generated when the cement is placed in the well, regardless of how long ago that cementing may have taken place. Thus, a requirement that the evaluation be less than two years old is not appropriate. Evaluation of cement bond quality after emplacement is covered by integrity testing requirements.*

0010-21

§1726.5(b)(13): Ensuring that wellhead components meet appropriate design and operation parameters is crucial to achieving and maintaining mechanical integrity. As such, commenters recommend that the Division adopt standards for wellhead components for gas storage wells, such as those adopted by Kansas (See K.A.R. § 82-3-1003(f)) that include a requirement for components made of steel having sufficient pressure rating to exceed maximum injection pressure with ratings stamped on valves and fittings. It should also require master valves to be fully opening and sized to the diameter of the tubing, with each flow line equipped with a manually operated positive shutoff valves.

Response*: NOT ACCEPTED. All emplaced equipment must be tested to ensure it meets minimum integrity standards, but the Division does not believe that the prescriptive requirements proposed by commenters are necessary. Risk assessment under the RMP will determine the appropriate well configuration based on performance standards which require zonal isolation and mitigation of hazards. Commenters' specific requirements for the master valves may be appropriate in some situations but not others. Shut-off valves would usually be found on the Christmas tree, not the flow lines, and automatic valves with manual bypass are often used.*

0005-35

§1726.5(c): There should be no reason why these specifications cannot be met. The criteria in subdivision (b) are essential to ensure well safety and integrity. Deviation from the specifications should be allowed only upon the provision of detailed evidence that an alternative design will be as effective or better, and any approval of alternatives should be fully transparent with ample public notice and opportunity for comment.

***Response**: NOT ACCEPTED. There are many reasons why well configuration may vary from the default examples described by the regulations. Well design and construction must adapt to geologic variation and site-specific characteristics; there may be times when a double-casing is more appropriate than tubing and packer. The Division must be flexible if it is to ensure that local conditions are accurately accounted for and such flexibility will provide for better protection than a one-size-fits all standard. Evaluation of the scientific data and determination of the appropriate configuration are a scientific and engineering decision not appropriate for public comment; the process would create unreasonable delay without clear regulatory benefit.*

1726.6 MECHANICAL INTEGRITY TESTING

0005-38
§1726.6: The regulations should require that all mechanical testing reports that are submitted to the Division be made publicly available.

***Response**: NOT ACCEPTED. As required under SB 887, documents and data submitted to the Division pursuant to these proposed regulations, and not determined to be confidential, will be made available to the public via the Division's website. The Division's well database is currently being upgraded and modernized. With these requirements and procedures already in place, an additional requirement for data release in the proposed regulations is not needed.*

0010-22
§1726.6(a): Even wells that do not intersect the intended reservoir(s) or caprock can act as conduits for gas to migrate into groundwater or the atmosphere if gas migrates beyond the vertical and/or lateral confining zone(s) and encounters shallower wells lacking mechanical integrity. As such, mechanical integrity testing should not be limited to only gas storage wells or other wells that penetrate the gas storage reservoir, but rather should be performed on all wells in the gas storage project.

***Response**: NOT ACCEPTED. A well which does not intersect the storage reservoir can only become a conduit if the confining strata fail or a well in the zone has compromised integrity. All wells that intersect the storage zone will be regularly tested ensuring that migration to shallower wells, which do not cross the storage zone, does not take place. Where confining strata have been compromised, the entire project may need to be re-evaluated and remediation action taken, which can be ordered at the Division's discretion if needed to protect life, health, property, the environment, or natural* *resources. The Division sees no regulatory purpose to the testing of wells which do not penetrate the storage zone.*

0008-10, 0011-7, 0015-32

§1726.6(a)(2): Commenters believe there is a typographical error in this subdivision. The proposed language indicates a requirement to employ such methods as “magnetic flux <u>and</u> ultrasonic technologies,” when the intent was to require the employment or such methods as “magnetic flux <u>or</u> ultrasonic technologies.”

***Response**: ACCEPTED. This language has been revised as recommended by Commenters.*

0011-8

§1726.6(a)(2): If the selected logging process under this section involves magnetic flux technology, it may not be possible to “include a repeat section of no less than 200 feet” that can provide comparable results to the original logging run within a reasonable timeframe. This is due to the residual magnetism on the casing immediately after the initial logging pass, which may cause an inaccurate second log. Commenters recommend inserting as “if practicable” qualifier in this requirement.

***Response**: NOT ACCEPTED. The issue with residual magnetism on the casing can be managed by providing sufficient time for the magnetic field to disperse before the second pass; the regulation does not require that the test be performed immediately or that the results be exactly the same. Reasonable results based on the limits of the technology will generally be acceptable to the Division, but the repeat section requirement remains applicable.*

0010-23

§1726.6(a)(2): If casing inspection reveals that significant corrosion may be occurring, the Division should require such wells to undergo more frequent and enhanced corrosion monitoring, in addition to actions to remediate corrosion. The Division’s proposal to allow a less frequent corrosion inspection schedule lacks sufficient detail or guidance on acceptable methods for determining a corrosion rate and assessing any changes in the rate over time that may necessitate a change in the inspection frequency. Commenters suggest adding language to require a thickness inspection “as part of any well rework where the tubing is removed” and to require a corrosion monitoring program when significant corrosion is possibly occurring. The corrosion monitoring program must include “monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis."

***Response**: NOT ACCEPTED. The gas transported within a gas storage project is already treated, pipeline quality gas with known lower corrosion rates; making a prescriptive requirement for more frequent testing excessively burdensome with limited regulatory value. As required by the RMP, corrosion mitigation measures must be identified as part of the corrosion risk assessment and response. The Division does not specify standards for a less frequent casing thickness inspection schedule because it will accept any method that meets the performance standard and wishes to leave open which technologies and methods may be used to make that demonstration. Monitoring using a real-time data system will be required for all operators by 2020, and the Division always has the discretion to require additional testing or mitigation measures as needed to prevent harm to life, health, property, natural resources, or the environment.*

0004-3, 0008-8, 0015-7
§1726.6(a)(2) and (3): Commenters encourage the Division to require that mechanical integrity testing (MIT) selection and frequency be based on risk assessment and the RMP, on a well- and facility-specific basis. Commenters appreciate the revisions to the minimum frequency of pressure testing from a standard default timeframe to a well-by-well risk basis, and urge the same changes to the frequency of casing wall thickness inspections. The final regulation should require operators to determine the appropriate frequency for integrity testing for each well based on risk assessment rather than defining a default timeframe. Commenters MIT protocols are aligned with the guidance in API RP 1171 that was adopted by PHMSA in their Interim Final Rule. API RP 1171 outlines a risk-based methodology, which involves data collection, documentation and review, hazard and threat identification, risk assessment, preventative and mitigative measures, and periodic review and reassessment.

***Response**: NOT ACCEPTED. PRC section 3180 requires the Division to create a schedule for ongoing mechanical integrity testing; basing the testing requirement solely on risk is inconsistent with this statutory requirement. The language revisions in this draft indicate that the Division expects and encourages operators to propose a testing frequency for approval based on risk, however, until such approval has been obtained the default requirement of 24 months remains applicable.*

0005-36
§1726.6(a)(2) and (3): Mechanical integrity testing should occur annually: the two-year intervals allowed in this section are simply too long. Annual testing is reasonable and

essential to protect public health and welfare. Furthermore, corrosion testing should not be allowed to slip to longer intervals, regardless of observed corrosion rates. Allowing a longer interval upon a finding of little corrosion will provide a perverse incentive to operators to underreport corrosion.

***Response**: NOT ACCEPTED. The two-year mechanical integrity testing schedule was developed in consultation with the National Labs, based on known averages of corrosion rates in gas storage wellbores, and is consistent with industry best practices. This schedule will be the most rigorous in the nation when the proposed regulations become effective. In addition, although the regulations provide a default schedule for MIT, operators are required to determine the appropriate testing schedule consistent with the risk-based approach that forms the core of these proposed regulations. The risk analyses may indicate that the default schedule is inappropriate in cases where there is little or no corrosion, or where there is corrosion in excess of expectations. Where an operator has not demonstrated the appropriate frequency using risk analysis supported by scientific evidence, the default will apply.*

0010-24
§1726.6(a)(3): Part I internal mechanical integrity should be demonstrated by requiring owners or operators to continuously monitor injection pressure, rate, and injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume. Commenters recommend the replacement of this section with a requirement for continuous monitoring as required under 1726.7(d).

***Response**: NOT ACCEPTED. Commenters' recommendation would remove the requirement for pressure testing every 24 months which is not acceptable to the Division; SB 887 also requires a schedule for ongoing mechanical integrity testing, making commenters' recommendation inconsistent with statutory requirements. The two-year pressure testing is necessary to ensure that the casing can withstand full pressures plus a safety factor, which will not be reached during regular operations. Continuous monitoring is a separate requirement that works in concert with regular mechanical integrity testing to ensure all potential hazards are detected.*

0011-9
§1726.6(a)(3): Commenters have significant concerns that periodic testing at elevated pressures as required by this provision is unprecedented in facilities of this type and could have detrimental consequences on casing joint integrity, downhole equipment seals, and the casing/cement bond. Commenters suggest that after the initial

hydrostatic test has been performed, the timing of subsequent pressure testing could be tied to corrosion logs and the results of the updated RMP.

***Response**: NOT ACCEPTED. Commenters' suggestion for an initial test with subsequent testing based on corrosion logs and the results of risk assessment appears generally consistent with the requirements of the proposed section provided the Division approves the proposed testing frequency. The operator will need to provide the Division with data (such as corrosion logs and the results of quantified risk assessments) that support the scientific adequacy of the frequency proposed. Where an operator has new information that would justify a change in the approved frequency, it can seek additional approval from the Division to update its RMP testing schedule. Revision to the regulatory requirements is not needed.*

0011-10, 0014-2

§1726.6(a)(3): Commenters draw attention to an invalid reference that was not updated to account for section changes since the last draft. The reference in this section should be corrected to 1726.3~~(c)~~(d)(3), which discusses schedule for verification and demonstration of mechanical integrity.

***Response**: ACCEPTED. The reference has been corrected. Thank you for catching the error.*

0010-25

§1726.6(b): The Division's proposed revision that some or all of the MIT requirements for a reworked gas storage well may be waived based on the nature of the work performed is vague. Commenters request that the Division provide additional clarification as to the purpose and intent of this provision. Maintaining mechanical integrity is critical to protecting human health and safety and the environment and mechanical integrity tests should not be waived without adequate justification.

***Response**: CLARIFICATION AS REQUESTED. This provision was revised in response to comments received which suggested that "rework" is a broad category likely to include activities where the performance of the full suite of integrity testing creates more risk than benefit, or is otherwise unwarranted by the circumstances. The default of this provision is that all mechanical integrity testing must be performed after every rework; where an operator can demonstrate to the Division, using scientific data, that such testing will not enhance well containment assurance or may otherwise lead to a greater risk of integrity loss, a waiver may be considered appropriate.*

0005-37

§1726.6(d): This section requires notice so that Division staff "may have an opportunity to witness testing." This is insufficient; the regulations should require that Division staff be present and witness, at a minimum, all annual pressure tests.

0010-26

§1726.6(b): Commenters recommend that the Division commit to witnessing a minimum of 25% of all mechanical integrity tests and provide language ensuring that operators shall not be subject to penalty due to the Division's inability to witness this minimum if the operator has complied with all other subdivisions of this regulation.

***Response to comments 0005-37 and 0010-26**: NOT ACCEPTED. There are more than 450 gas storage wells in the state of California and the Division does not have the resources to be present at and witness all testing or even all pressure testing. It also cannot commit itself to a numerical goal (25%) that it may be unable to meet based on current or future resource allocations. The Division will witness those mechanical integrity tests it feels are necessary to ensure that regulatory goals are being met. With that in mind, however, the Division has expanded its UGS enforcement and program staff in the last few years; along with a requirement for 48-hour notice prior to testing this should facilitate an increased number of witnessing events under the proposed regulations.*

0010-27

§1726.6(e): Commenters recommend that the Division specify what actions must be taken in case of a failed mechanical integrity test by adding a requirement to isolate the leak or leaks and demonstrate that the well does not pose a threat to protected water resources or public safety. Commenters recommend the additional requirement: Within 30 days the operator shall repair and retest the well to demonstrate integrity, or plug the well.

***Response**: NOT ACCEPTED. There can be many reasons for a failed mechanical integrity test, which may or may not include an actual leak. When a well fails a test, the operator is required to notify the Division, and injection and withdrawal must cease until the well has been remediated to the Division's satisfaction. As the reasons for a failed test are broad, the universe of potential remediation actions is even broader; it would be impossible to list all of the possible circumstances and potential responses in regulatory text. In addition, thirty days is insufficient time to respond to many integrity failures, which may involve ordering of parts and/or contracting for a rig. The Division has at all times the discretion to require the operator to perform additional testing, add additional* *remedial measures, shut-in the well, or require it to be plugged, and this discretion will be exercised on a case-by-case basis depending on the circumstances of the test failure.*

1726.6.1 PRESSURE TESTING PARAMETERS

0011-11

§1726.6.1(a)(5): Any requirement to pressure test gas storage wells to 115 percent of the maximum allowable injection pressure using liquid would result in much higher pressures at the bottom of the wells. Commenters' wells can be as deep as 3,000 to 9,000 feet, and the hydrostatic pressure at the bottom of the well resulting from this type of test would be potentially more than 200 percent in some cases. A test of this nature could be unsafe and potentially damage a well. A pressure test using gas instead would not be as likely to damage a well, but could result in releases of significant amounts of natural gas as each test is completed, which would be contrary to the state's goals in limiting methane emissions. Commenters recommend that this section be modified to require pressure tests at an initial pressure "calculated at the depth of the packer, at least as high as 115% of the maximum allowable injection pressure encountered at that depth."

***Response**: NOT ACCEPTED. The Division recognizes that operators will be required to perform block testing to meet these requirements. Operators should test each block to 115% of the maximum allowable injection pressure.*

0008-21

§1726.6.1(b): Commenter recommends the addition of language "if the pressure test is unsuccessful per Section 1726.6.1(a)(6)" to initiate the provisions of Section 1726.6.1(b).

***Response**: NOT ACCEPTED. The intent of subdivision (b) is to allow for modification of the testing parameters by the Division without a requirement for an unsuccessful pressure test first. This could be at the request of an operator, who knows of circumstances that would justify a modification of the parameters, or could be triggered by the Division based on its knowledge and analysis. In either case, an unsuccessful pressure test is not an appropriate threshold requirement as it would unreasonably limit the circumstances when such modifications could be approved.*

1726.7 MONITORING REQUIREMENTS

0001-2
§1726.7: What is being done to monitor venting? How much is really ‘unplanned’ venting? Shouldn’t any venting have scrubbers to remove the nuisance and toxic components?

***Response**: NOT ACCEPTED. Venting procedures are regulated by air quality management districts, and are outside the scope of the proposed regulations.*

0005-40
§1726.7: Continuous monitoring requirements should include continuous monitoring of ambient air to detect dangerous levels of air pollutants above ground, including but not limited to, criteria pollutants, methane, VOCs including BTEX (benzene, toluene, ethylbenzene and xylenes), metals, hydrogen sulfide, and polycyclic aromatic hydrocarbons. It is also essential that monitoring occur within the facility, at the fence line, and in nearby communities, and that that the public have access to all monitoring data.

***Response**: NOT ACCEPTED. These issues are within the scope of the California Air Resources Board’s recently completed Oil and Gas Regulation rulemaking.*

0005-41
§1726.7: Monitoring of groundwater in nearby aquifers should be also required in order to verify that isolation is achieved. The groundwater monitoring criteria developed for well stimulation projects should be examined for applicability to injection projects. The United States Geologic Survey (USGS), in a paper commissioned by the State Water Resources Control Board, asserts that the impacts of well stimulation on groundwater may be indistinguishable from enhanced recovery (i.e. Class II wells), as the same contamination pathways, and similar chemicals may be present. Monitoring groundwater for impacts from underground injection wells would be consistent with the State’s current program of monitoring groundwater for impacts from well stimulation. One transferable aspect of the well stimulation monitoring program is the regional groundwater monitoring programs being developed for oil fields where stimulation occurs. These plans should also be developed for any fields where underground injection occurs. Well by well monitoring should also be considered, especially in cases where injection wells penetrate, or are adjacent to, aquifers with beneficial uses.

***Response**: NOT ACCEPTED. Although groundwater monitoring is a possible tool for responding to indication of a lack of fluid confinement, the additional benefits of adding groundwater monitoring as a categorical requirement for all UGS facilities are not clear.*

0005-39

§1726.7(a), (d), and (f): Commenter strongly supports the Division's requirement for continuous monitoring of conditions at gas storage wells. A phase-in time of January 1, 2020 is far too long, however. It is feasible for operators to equip their facilities sooner than early 2020. There is simply too great a risk of a repeat of the Aliso Canyon disaster. Operators should be required to employ a continuous, real-time monitoring system with integrated warning systems (CEMS) in order to monitor for the presence of annular gas and fire and leak detection on all wells.

***Response**: NOT ACCEPTED. Many operators use continuous monitoring systems and are already in compliance with the proposed regulatory requirement. As the proposed regulations are unlikely to become effective until late 2018 or early 2019, a timeframe of approximately one year is a reasonable compliance period for those not yet in compliance. All operators are required to perform daily leak surveys which will temporarily provide sufficient leak detection until the real-time monitoring systems can be installed.*

0015-34

§1726.7(d)(3): Commenter recommends that the alarm set point should be set by the operator at a reasonable maximum pressure, rather than an arbitrary threshold of 100 psi.

***Response**: ACCEPTED IN PART. The default alarm set point under the proposed section remains at 100 psi. However, the language has been edited to reflect that an operator who has gone through the process at 1726.7(d)(3)(C) and identified a new alarm set point which has been approved by the Division, will be allowed to use that approved new alarm set point going forward. Although this does not provide an operator-set threshold as proposed by commenter, it provides a procedure whereby a site-appropriate set point can be developed and approved.*

0010-28

§1726.7(e): Commenters request clarification on why the requirement to run gas detection logs annually was struck from this subdivision.

***Response**: CLARIFICATION AS REQUESTED. The Division received multiple comments regarding the requirements of this* subdivision *indicating that there was confusion as to when they would be triggered and conflicting perspectives on what the correct requirement should be. One commenter submitted language which constituted a* *complete process – beginning with a baseline and in coordination with the required casing integrity assessment every 24 months, ongoing risk analysis, multi-year comparisons, and other indicators would be used to determine the need for a detection log, and/or the appropriate frequency for ongoing subsequent testing. As the Division felt this schema was consistent with the performance standard/risk assessment approach used throughout these proposed regulations and resolved much of the confusion indicated by the comments, it was incorporated into this first revision of the proposed regulations.*

0011-12
§1726.7(e): Commenters understand the value of an initial log to detect gas indications behind casing, but question the need for repeated subsequent logs unless results from the testing and monitoring already requires in 1726.6 and 1726.7 suggest a leak of storage gas. Commenters recommend edits to this requirement deleting any reference to subsequent or comparison logs unless "future evidence" suggests that storage gas may have accumulated behind the casing. Changes to the indicated gas behind the casing would be noted and reported to the Division.

***Response**: NOT ACCEPTED. Commenters' interpretation of the language of the proposed section is not consistent with the requirement as written. The proposed section requires a program for submission to the Division for review and approval. That program must include a plan for the baseline detection log and subsequent logs. Where the program indicates that subsequent logs are needed, they must be submitted to the Division and compared with previous logs. Some number of or trigger for subsequent logs must be included in the program to ensure that baseline conditions have not changed and gas migration behind the casing is detected and remediated if necessary.*

1726.8 INSPECTION, TESTING & MAINTENANCE of WELLHEADS & VALVES

0005-42
§1726.8(a): Safety valve testing should be conducted in the presence of Division staff to ensure proper testing protocols are followed. Furthermore, if safety valves are found to be faulty or inoperable, the repair time should be less than 90 days, and then only if there is an operational back up valve. If there is not an operational back up valve, all activity at the gas storage project should cease immediately, and the well temporarily plugged, until full repair is complete. Only if the well has been plugged should Division allow the operator to propose an alternative time frame for addressing an inoperable safety valve.

***Response**: NOT ACCEPTED. The Division does not have the staff to witness all safety testing as commenter would require, but will witness sufficient and targeted tests as needed to ensure the goals of the regulations are being met. When a faulty valve is identified, repairs usually require rig mobilization, which can take significant time depending on cost, availability, and site accessibility. It is unlikely to be practically feasible for operators to repair all inoperable valves within a shorter timeframe than 90 days. Where the absence of a valve presents a hazard, operators will be required to perform a risk assessment and implement appropriate mitigation measures, up to and including shut-in if needed.*

0015-35
§1726.8(a): API RP 14B applies to surface *safety* valves. Commenter recommends clarifying that here for alignment.

***Response**: ACCEPTED. The word "safety" has been added for clarity.*

1726.9 WELL LEAK REPORTING

0007-6
§1726.9: When reporting any incidents such as leaks and spills, operators should not make any determination of the effects on health and safety, as they lack any standing of medical expertise. In addition, when local public health officials request information, such as a list of chemicals used on its site, the operator should be required to supply such information.

***Response**: NOT ACCEPTED. The regulations do not require the operator to quantify the actual or likely effects on health and safety in reporting a leak, but the operator must be prepared to report the potential severity of the leak and a reasonable estimate of the likely harm that will result so that the urgency of response can be determined. The proposed regulations would be additional to other existing reporting requirements applicable to leaks and spills.*

0010-29
§1726.9: The Division indicates in the ISOR that it relied on CARB proposed regulation to determine what constitutes a "reportable leak" under PRC section 3183, subdivision (a). However, in addition to the Division's proposed requirements, CARB also requires that, "within 24 hours of receiving an alarm signaled by a downwind air monitoring sensor(s) that detects a reading that is greater than four (4) times the downwind

sensor(s) baseline, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the emissions measurement." Cal. Code Regs., tit. 17, §§ 95673(a)(9). The Division should also include this in its regulation of what constitutes a reportable leak.

0008-11

§1726.9(a)(1)-(3): Commenter proposes aligning the definition of a leak, where these sections currently duplicate CARB's definition, by replacing with a direct reference to CARB which will maintain and preserve consistency of definitions between the two regulations, which is necessary to ensure compliance and to avoid enforcement ambiguity.

0013-13

§1726.9(a)(2): There should be additional continuous monitoring procedures to ensure levels do not rise above 50,000 ppm, once it is detected above 10,000 ppm. Commenter, therefore, recommends additional language requiring this continuous monitoring, consistent with section 1726.7.

0005-43

§1726.9(b): If a gas storage well has a reportable leak, in addition to the requirement that the operator immediately inform the Division, the Division should be required to post reported leaks on its website within at least 3 days of receiving the report. The Division should be required to maintain a database of reported leaks, with information on any steps or measure taken to remediate or otherwise address them. Additionally, we support the comments of Drs. Oldenburg and Budnitz (submitted Oct. 5, 2017) that the leakage be quantified and measured in flow units rather than concentration units.

Response to 0005-43, 0008-11, 0010-29, 0013-13*: NOT ACCEPTED. The limited purpose of proposed section 1726.9 is to implement the specific requirements of PRC section 3183 and 3184. PRC section 3183, subdivision (c), requires that for a "reportable leak" that is not controlled within 48 hours, the Division must post information about the leak on its Internet website and provide regular updates to the public until the leak is stopped. Public Resources Code section 3184 further requires that within 72 hours of being notified of a "reportable leak," the Division shall make a determination as to whether the leak poses a significant present or potential hazard to public health and safety, property, or to the environment such that a relief well is necessary. If the State Oil and Gas Superivosr makes that determination, the operator shall immediately begin preparation for, and, as soon as practicable at the determination of the Supervisor, commence the drilling of, a relief well.*

Public Resources Code section 3183, subdivision (a), requires the Division, in consultation with CARB, to adopt regulations defining a "reportable leak" and establish the timeframe for reporting such leaks to the Division. Proposed section 1726.9 responds to these statutory mandates. Commenters suggestions are beyond the scope of proposed section 1726.9 and they relate to issues that are addressed elsewhere in the Division's and CARB's regulations.

The requirement to report to the Division all surface and cellar gas releases, of any size from a gas storage well already appears in proposed section 1726.7(c) as part of the monitoring protocols. Daily inspections for leaks in the area around gas storage wellheads are addressed in proposed section 1726.7(f) and in equivalent requirements recently promulgated by CARB. Where a pressure change, alarm, or other data indicate a problem that falls under the jurisdiction of the Division, written reports and formal action may not be appropriate or cost-effective in all circumstances, such as a small leak easily controlled or a readily explained pressure change. However, all written reports of incidents would be included in the appropriate well or project files, which are made available on the Division's public website in accordance with PRC section 3187.

PRC section 3183 prescribes requirements for the Division to post information about reportable leaks on its public website.

0013-14
§1726.9(b): Language should be added to clarify that in the case of a reportable leak, the operator must immediately inform the Division and local authorities as required by law. This should be consistent with H&SC, Chapter 6.95, Article 1.

***Response**: NOT ACCEPTED. A requirement to inform the Division is already included. Where an operator may be required by law to notify other authorities, it is the duty of the operator to identify and comply with those legal requirements. Such compliance is not conditioned on duplication of other agency regulatory requirements in the Division's regulations, making a cross-reference unnecessary.*

1726.10 REQUIREMENTS FOR DECOMMISSIONING

0005-44
§1726.10: Decommissioning plans should be made available for public review and comment.

Response*: NOT ACCEPTED. The Decommissioning Plan will be focused on the safe shut down of well operations including plugging and abandonment of wells, and will be posted on the website for public information once it has been approved. Aspects of a Decommissioning Plan may necessitate a public comment process, but committing to a public notice and comment period for the creation of the plan may create unnecessary delay for the processing of a plan that will already be complicated by the number of regulatory agencies involved.*

0013-15

§1726.10: The regulations should require timeframes for submitting and approving a decommissioning plan to ensure accountability, consistency, and compliance. Additionally, there should be a requirement to have a qualified engineer approval/stamp and signoff on the Decommissioning Plan to provide for additional reliability and oversight.

Response*: NOT ACCEPTED. The Decommissioning Plan is a complex document highly dependent on the site-specific hazards and characteristics associated with a UGS project. The timeframes for an effective review of a small project plan that involves less than ten wells (6 of 14 projects in CA), would be significantly different than review of a project with more than thirty wells (3 of 14 in CA). Urban versus rural location and potential for environmental contamination would also be compounding factors in developing the Decommissioning Plan. Because of these complexities, the Division cannot set regulatory requirements based on what is appropriate for one size project without creating excessive or insufficient regulation for other project sizes. Thus, the plan timeframes will be determined on a project-by-project basis in coordination with the CPUC and its decommissioning process. A qualified engineer signoff is not appropriate; very few of the processes involved in decommissions are engineering-specific, and the Division has experienced engineers, geologists, project managers, and administrators who will work with operators to ensure a complete and legal plan rather than one based on the judgment of a single engineer.*

0015-12

§1726.10: Commenter appreciates the need to consult with the CPUC when submitting a Decommissioning Plan and that both agencies will need to be involved. However, commenter notes that the Division has not specified a process or timeline for its review and approval of the plan, which is essential to ensuring reliability and should be clearly defined and added as a required component. Commenter proposes that the Division should review and provide approval or note any deficiencies in the plan within 180 days of submittal.

***Response**: NOT ACCEPTED. Size, location, and associated hazards will complicate the details of a Decommissioning Plan, making it impossible for the Division to commit to a specific timeframe for review and approval. Because decommissioning of a field must also be approved and managed in cooperation with the CPUC, the decommissioning process will not just be a plan submission and approval, but a collaborative process between operator, CPUC, Division, and CalEPA staff to ensure that the plan provides for and actually achieves the protections required by statute.*

0015-13
§1726.10: Commenter notes that the requirements of these revised regulations would only be applicable until the Division approves a Decommissioning Plan, thereby acknowledging that a project is no longer an underground storage project as defined under the jurisdiction of this regulation.

***Response**: NOT ACCEPTED. The project will remain subject to all UGS regulations, both existing and proposed, until such time as the approved Decommissioning Plan, and all the work required thereunder, is certified as complete by the Division. This is necessary because the hazards to life, health, property, natural resources, and the environment do not disappear just because a Decommissioning Plan is in place. The Division will continue to monitor the project even after the decommissioning has been completed and approved and may, at any time, require re-entering and re-abandonment where appropriate. Where ongoing operations and/or actions approved under the Decommissioning Plan are inconsistent with regulatory requirements, the Decommissioning Plan will provide for approved variance as needed.*

0010-30
§1726.10(a): Properly closing gas storage sites is critical to protecting public health and safety and the environment. Commenters recommend revisions and additions, consistent with the best practices used in other states and jurisdictions (see e.g. K.A.R. 82-3-1011(f) and 40 CFR § 146.93). Specific revisions include the requirement for "a detailed schedule…in writing at least 120 days before site closure." The plan should address the anticipated date of abandonment and decommissioning; anticipated field pressure at abandonment; plugging of all wells; identification of facilities to be abandoned; names of person who will be responsible for surface facilities; surface restoration including closure of surface impoundments; removal of any unused equipment, materials, and debris; and disposal of all wastes. Operators should be required to submit a site closure report within 90 days of closure, which the Division must retain for 10 years. The closure report must include documentation of well

plugging and a survey plat showing the location of wells. Operators must record a notation on the deed that provides information to future purchasers regarding the use of the land for UGS, the name of the State agency holding the survey plat, and the volume of gas remaining in the storage reservoir.

***Response**: NOT ACCEPTED. The detailed and prescriptive requirements suggested by commenters are not needed in the regulations. The Division's oversight will be focused on the plugging and abandonment of the wells and site restoration at the wellhead; the shut-down and disposal of facilities and equipment as well as post-decommissioning field maintenance is the responsibility of the CPUC. Well location is already known and contained within Division files, which are maintained in perpetuity. Commenters' proposed timeframes are unrealistic; a decommissioning is likely to take two years or more and will require risk assessment and adaptation of the plan as each well is evaluated and then plugged and abandoned. Where a* Decommissioning Plan *may be submitted without information needed by the Division, it will not be approved until all aspects of the plan have been addressed so as to ensure the ongoing protection of life, health, property, natural resources, and the environment both during decommissioning and after project closure.*

MULTI-SECTION COMMENTS

0005-5

§1726.2 and 1726.3(a): Critically, it is unclear what requirements and criteria the Division will use to determine whether to issue a PAL. The proposed regulations should make clear that all documents and data are required, including RMPs, to be submitted *and approved* prior to the Division issuing a PAL. Further, since the decision to issue a PAL is discretionary, what are the conditions under which the Division will or may *not* issue a PAL? The requirement that operators obtain a PAL should be accompanied by a process for public notice and opportunity for comment. We also note that because the Division's decision to issue a PAL is a discretionary action of the agency, any such approval would be subject to CEQA.

***Response**: NOT ACCEPTED. The process of generating a PAL for a new UGS project will begin while the project is still undergoing its initial review and authorization with the CPUC. Local land use entities are also involved in the permitting of new projects, and go through their own review, comment, and impact evaluation process based on local permitting requirements. Thus, the CEQA process for the proposed project will be managed by CPUC or the local permitting agency as the lead agency, and will identify risks to the environment as well as mitigation requirements for the entire project, based* *on the proposed scope of the project including the proposed number and location of wells, and the volume of operational activities. The Division will participate as a responsible agency in the evaluation of the geology of the site and its appropriateness for UGS based on the data submissions.*

Using the CEQA results and their own analysis, the operator will develop the RMP and submit it along with supporting data to the Division during this initial process. The PAL will be issued once the location has been approved by the permitting agencies and a complete RMP is approved with provisions for mechanical integrity testing, monitoring, and hazard prevention and mitigation activities as required by these proposed regulations and the CEQA report. The PAL will condition ongoing approval of the project on compliance with all laws and regulations, with updates required as conditions or project operations change. Any significant change in project scope would again require CPUC and local agency involvement.

Given the level of public notice and comment required during the initial project approval process, the Division sees no value in a duplicate process for the subsequent PAL.

0005-7
1726.3(b): The regulations require that the RMP “shall demonstrate to the Division’s satisfaction that store gas will be confined to the approved reservoir and that risks of damage to life, health, property, the environment, or natural resources are identified an effectively mitigated.” “To the Division’s satisfaction” is too vague. The regulations should specify specific standards and targets required to demonstrate these factors.

0008-13
§1726.3(b), 1726.5(c), 1726.7(c): Commenter recommends revising "shall demonstrate to the Division's satisfaction..." and replacing with "shall demonstrate to the Division…". As with other regulations, operators will be responsible for complying with the final version of proposed regulations. These proposed regulations set forth with detail the expectations and contents required for such plans. Further, the Division can already impose consequences on operators for failing to comply with the regulations or require additional data, risk assessment, or modification of mitigation protocols. In this case, the use of the word "satisfaction" is not only redundant, but introduces a temporal step that is outside of the operator's control and can lead to delays and costly last minute revisions.

Response to comments 0005-7 and 0008-12*: NOT ACCEPTED. The phrase “Division satisfaction” is used when an operator will propose a method or demonstrate a finding* *using an alternative to the default requirement. This regulatory structure is a compromise between strict prescriptive requirements and no requirement at all, striking a balance between flexibility for operators based on risk and the need to hold operators accountable to protect public health and safety. The text revisions proposed by commenter would suggest that so long as the operator has made a demonstration, the Division must accept it, which is not the regulatory intent. As the Division is responsible for ensuring that operators comply with the regulations, Division staff must be satisfied that the demonstration is adequate to show that the performance standards have been met.*

0002-1, 0007-4

§1726.3(d)(2)(L) and §1726.5(a): Given that there are hidden faults that often go unnoticed, when faults in close proximity to gas storage facilities become identified and mapped out, the nearby sites need to be immediately evaluated as to the risk during a major eruption. When seismic studies demonstrate a danger due to earthquakes, a storage site should be considered for decommissioning. The danger from wells collapsing during a strong enough shaking could lead to a massive loss of the gas, as well as explosions and fires that will strain local firefighting services that will already be strained. Previous warnings and concerns have been ignored by operators and the Division. As earthquake experts have determined that Southern California is due for a strong earthquake in the near future, shouldn't this danger be acknowledged by the Department of Conservation? The probability of earthquake as a natural cause of risk must be included, and section 1726.5(a) should state "earthquake" as a potential root instigator of a single failure.

Response: *NOT ACCEPTED. Operators must evaluate the risk associated with seismicity as a required element of the RMP. Where faults may be in close proximity to, and/or cross the storage field, the operator must identify the potential harms which could occur during a seismic event including shaking and shear; potential harm to wells as a result of shaking from more distant seismic activity must also be considered. The harm must be prevented and mitigated to the extent technologically feasible and the ERP must prepare for different types and intensities of seismic event. The Division does not have the authority to require decommissioning of a project solely based on seismic risk, but will require prevention and mitigation measures necessary to manage that risk. Concerns associated with seismic activity are not unique to gas storage facilities and many agencies, including the California Geologic Service (a part of the Department of Conservation), are seeking systemic solutions to this pervasive issue.*

0005-10, 0007-2

§1726.3(d)(2) and §1726.5(b)(1)(A): Surface or subsurface safety valves, with both automatic *and* remote-actuated valves, and an incorporated warning system, should be required for *all* gas storage wells, not merely depending on the well's distance from populated areas. Well leaks and accidents can harm people, structures, and the environment many miles away. The methane leak in SS25 at Aliso Canyon resulted in thousands of people several miles away being relocated from their homes, and contributed significantly to the state's greenhouse emissions. In Kansas, gas leaked from a well through faulty casing and traveled nine miles underground to downtown Hutchinson, where a resulting explosion destroyed two businesses and killed two people. Leaks and fires contribute to air pollution which affects thousands of people. Therefore, these safety valves should not be required only based on certain criteria (which inexplicably exclude proximity to homes and sensitive receptors); they should be required for all wells. In addition, the SSSVs must be able to be operated onsite and remotely, and must automatically close when there is either a significant loss of pressure, or if the maximum operating pressure is exceeded.

Response*: NOT ACCEPTED. It is the intent of the proposed regulations to set performance standards using hazard analysis and QRA, rather than specific prescriptive requirements for well design and construction. As such, section 1726.3(d)(2) requires operators to determine if surface, subsurface, or remote-actuated safety values are appropriate considering a list of factors including proximity to homes, occupied buildings, and sensitive areas, as well as current and predicted surrounding development, and the availability of alternative protection measures. Where an alternative hazard reduction strategy or technology may provide equal or greater protection than a safety valve, the Division would encourage the use of the alternative. A prescriptive requirement for valves in all wells, regardless of appropriateness or need, would vitiate the risk-based, performance-focused approach that is the goal of these proposed regulations. The standard, as designated by statute, is the requirement for no single point of failure, which requires two mechanical barriers but does not dictate otherwise how a well must be configured. For "critical wells" as defined under section 1720, surface fail-close, well shut-in or shut-down devices, and subsurface tubing safety valves are already required under 1724.3.*

0005-29

§1726.4 and 1726.4.3: Public disclosure of well records is essential to provide California residents with full access to information that impacts public health and welfare. Commenter recommends amending section 1726.4.3 to ensure that all well records are also publicly accessible. Furthermore, submitted data under section 1726.4

should be made available on the Division’s website. In fact, SB 887 requires it. The Division should not continue to ignore this requirement.

Response: *NOT ACCEPTED. Where statutory language is clear, such as the SB 887 requirement to make all submitted data available on the Division’s website, additional language in regulations is not needed to effectuate that requirement. As required under SB 887, documents and data submitted to the Division pursuant to these proposed regulations, and not determined to be confidential, will be made available to the public via the Division's website. At no time has the Division ignored this requirement. In fact, non-confidential records submitted were already posted to the website as part of Division standard operating procedures prior to SB 887. Where the Division does not have a regulatory need for specific well records, it cannot require them or require their release to the public.*

0005-26, 0010-12
§1726.4(a)(5)(F) and 1726.4.2(a)(1): Casing diagrams and evaluation should be required for all wells within the gas storage facility boundary, regardless of depth. Even wells that do not intersect the intended reservoir(s) or caprock can act as conduits for gas to migrate into groundwater or the atmosphere if gas migrates beyond the vertical and/or lateral confining zone(s) and encounters shallower wells lacking mechanical integrity. Operators should also be required to evaluate the potential to allow fluid migration outside of the approved zone of storage for all wells within the AOR that are in zones *above* the well, as well as those in the same zone or deeper.

Response*: NOT ACCEPTED. The requirements for casing diagrams and evaluation apply to all wells that are in the AOR and that are in the same or deeper zone as the gas storage reservoir. A shallow well that does not intersect the zone cannot be a conduit for migration unless the zone has already been compromised. By ensuring that all wells which penetrate the zone maintain their integrity via the regulatory requirements, concerns about secondary migration from shallower sources are mitigated. Thus, the Division has no regulatory need for casing diagrams or evaluation of fluid migration potential for wells that do not penetrate the storage zone.*

0010-13
§1726.4(a)(5)(H) and 1726.4.2(a)(1): The proposed requirements in these sections are not sufficient to ensure that all wells in a gas storage project will be assessed, and if necessary, remediated. Submitted data should also include a complete inventory and integrity analysis of existing wells. This should include all wells—whether active, plugged, abandoned, idled, or dry holes—that penetrate the gas reservoir or the AOR.

The assessment must evaluate each existing well and should include a well record review, field inspection and testing, and corrective action including reworking and plugging/re-plugging.

***Response**: NOT ACCEPTED. The data and evaluation requirements of these sections include identification of all wells associated with the project; each well must be evaluated for containment assurance and necessary mechanical integrity testing and logging must be performed. But the proposed section does not stand alone. The RMP section also requires that the construction and design of all wells conform to the requirements of these proposed regulations and provides a schedule for bringing nonconforming wells into compliance; the mechanical integrity section outlines the default testing requirements and risk-based alternatives. The requirement to demonstrate the integrity of all wells, along with the well construction standards, monitoring requirements, and risk assessments conducted under the RMP, will be sufficient to ensure that all wells are evaluated, with corrective action as needed.*

0008-7, 0011-5
§1726.4.2(a)(1) and 1726.5(a): Commenters acknowledge the prudence of implementing processes to prevent wells within the AOR and/or otherwise penetrate the gas storage zone from becoming a potential conduit for fluid migration outside the approved gas storage zone. However, commenters recommend revisions to these sections to provide that owners and operators of UGS projects are not responsible for third-party wells that are not associated with or part of the project, even though they may penetrate project storage reservoir. Rather, the relevant third-party owner or operator should be required to comply with any applicable well construction standards.

***Response:** NOT ACCEPTED. Where a third-party well penetrates the storage reservoir, the integrity of that well must be assured. The operator should work with the owner of the third-party well to ensure the required construction standards are met, even if the cost must be covered by the gas storage operator. Although it may be difficult to secure the cooperation of third-parties and additional cost may be incurred, in order to ensure that the integrity of the storage reservoir is maintained, the minimum construction standard for every well must be assured, regardless of ownership. Based on Division records, the scenario commenters describe—that of a UGS reservoir penetrated by a third-party well—currently does not exist in California, and appears to be entirely hypothetical.*

0014-3

§1726.5(b)(1)(A) and 1726.6(a)(3): This section discusses pressure testing of the primary mechanical barrier and refers to section 1726.6(a) that describes pressuring testing of the production casing and the casing-tubing annulus, but not internal pressure testing of the tubing – the primary barrier in a tubing-packer completion. Commenter suggests that 1726.6(a)(3) be revised to require the following for tubing-packer completions: a) an initial pressure test of the production casing prior to installation of tubing; b) an initial pressure test (internal pressure) of the tubing during or following installation of tubing; c) an initial pressure test of the casing-tubing annulus after installation of tubing and packer; and d) allow subsequent pressure testing to be satisfied by either internal pressure testing of the tubing (primary barrier) or pressure testing of the casing-tubing annulus (secondary barrier).

***Response:** NOT ACCEPTED. The Division determined that pressure testing of the tubing was unnecessarily duplicative when testing of the casing-tubing annulus would show defects caused by leaks in the tubing and when effective pressure testing with a safety margin at depth would require block testing that necessitates removal of the tubing and packer. Where a well configuration is approved that does not use tubing and packer, the primary mechanical barrier must be subject to pressure testing as required in subdivision (a)(3), but the additional testing recommended by commenter is not needed.*

0015-33

§1726.7(c) and 1726.9(b): Commenter recommends aligning the reporting requirements with the CARB reporting requirements in Sections 95673(a)(8) & (9) by requiring an operator to report unintended surface or cellar gas releases and reportable leaks to the Division within 24 hours, rather than “immediately.”

***Response**: NOT ACCEPTED. Leaks must be reported to the Division immediately so that it can monitor, inform, and coordinate response actions.*

0012-14

§1726.7(d)(3)(E) and 1726.9(b): Commenters add a requirement that, upon discovery of pressure build-up due to storage gas migration or on discovery of a reportable leak, “operators must immediately shut in the well unless doing so presents additional safety issues.”

***Response**: NOT ACCEPTED. Where the Division determines that it is justified due to a potential risk or known hazard, it has the statutory authority to order a shut-in at any* *time; a specific provision is not needed in the regulations to make this possible. In addition, many "serious" problems can be addressed without the need to shut-in a well, with appropriate mitigation measures used to reduce and prevent harm while addressing the discovered problem. Whenever such risks or hazards have been identified, the Division works with the operator to develop an immediate response plan including prevention and mitigation protocols, which may include shut-in, but such a requirement is not needed as a default.*