ATTACHMENT A:

STANDARDIZED REGULATORY IMPACT ASSESSMENT

UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

Standardized Regulatory Impact Assessment (SRIA)

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Executive Summary

The proposed Underground Injection Control (UIC) Regulations represent a significant overhaul to the Division of Oil, Gas, and Geothermal Resources' (Division) rules governing injection of fluids for purposes of enhanced oil recovery (EOR) and produced water disposal. Using cost figures provided by oil and gas production companies, this analysis takes a conservative approach to estimate the possible cost that could be imposed by these regulations. The proposed regulations include specific, rigorous standards that have two primary purposes. The first is to ensure injected fluids remain in the intended zone. The second is to ensure that injection wells used in both fluid disposal and EOR have verified mechanical integrity. The proposed regulations include specific requirements to meet these goals, however, they also provide substantial flexibility for operators to provide alternative methods for meeting these standards.

The proposed regulations take a risk-based approach to clarify and expand UIC project data requirements to improve analyses of projects and ensure that subsurface characteristics of projects are more fully understood and potential risks accounted for. They also add rigor to mechanical integrity testing to reduce risks associated with well failures and fluid migration beyond the intended zone of injection. In addition, they establish incident response requirements and provide requirements for preventing and responding to surface expressions.

The additional data and risk mitigation requirements impose significant additional costs on oil and gas operators in the state. To ensure a conservative estimate that represents a full consideration of possible costs, this analysis, unless otherwise specified, assumes that operators would be required to comply with the specific requirements outlined in the regulations. It does not capture potentially less costly approaches to compliance that could be proposed by operators and approved by the Division on a case-by-case basis to meet the general requirements of the regulations. As a result, this Standard Regulatory Impact Assessment (SRIA), may reflect an overestimate of the economic impacts of these regulations. This analysis projects costs over the first five years of implementation of the regulations. Unless otherwise indicated, the cost estimates for each requirement are primarily based on the results of a survey of oil and gas operators distributed to industry trade groups and operators. The total direct costs imposed on operators are indicated in Table 1, and range from $157 million to $235 million in the first five years of this analysis (see the Estimating the Direct Costs section of this report for a more detailed discussion).

Table 1. Total Statewide Costs of Proposed Regulations

	Year 1	Year 2	Year 3	Year 4	Year 5
Total	$221,050,456	$234,492,683	$156,811,474	$157,233,474	$156,935,474

Most of the state's UIC wells are owned by large operators (12 operators own 94 percent of the state's injection wells). The proposed regulations will require operators to divert spending from other priorities such as profits and dividends, research, and project development to cover the additional costs imposed by new testing, project data requirements, and other elements of the regulations. Not only are the proposed regulations likely to reduce operators' profit margins in the short-term, they may delay investments in new production to some extent. Despite these new compliance costs, the Division expects the typical UIC operator to be able to absorb the costs in the long-term.

Large operators have shown profitability even when crude oil prices and natural gas prices are low, demonstrating resilience in this volatile marketplace. In 2018 alone, prices for California crude have oscillated from just over $30 per barrel to over $70 dollar per barrel. This kind of price swing represents changes in potential gross revenue in the tens of billions of dollars on a statewide basis. On the other hand, small operators, or operators that generated less than $10 million each in gross revenue in 2017, could experience financial difficulty in complying with the proposed UIC regulations particularly if oil prices decline significantly in the near term while the oil industry will also be adapting to new idle well requirements, which are the subject of a separate regulatory package. For those operators who would already be experiencing financial hardship resulting from low oil prices, additional regulatory costs may, in some cases, result in driving them out of the business. The combination of lower profit margins and the possible exit of some small operators from the industry, California could experience a slight reduction in oil and gas production. However, given that California's oil production has been on the decline since 1985 and experienced one of the largest year to year drops in oil production in 2017, it would be difficult to say with certainty what, if any, fraction of the decline in production would be attributable to compliance costs associated with this regulation.

Because oil and natural gas prices are largely based on variables dictated on the global market[1, 2], individual operators cannot pass the costs of compliance on to the refineries. According to the California Energy Commission, California refineries already import nearly 70 percent of crude oil from out-of-state sources. Refineries will continue to purchase oil from outside of the state if in-state production is not adequate, a trend that has been increasing since 1999 (see Direct Cost Impact sections of this report on Typical Businesses, Small Businesses, and Individuals). The public at-large will not experience higher prices for petroleum products because of regulations affecting oil and gas producers. However, if the stock prices of publicly traded oil and gas companies are negatively impacted by the proposed regulations, then these operators could experience difficulty raising capital and individuals may see lower dividends and lower capital gains.

To estimate the broader economic impacts induced by the direct costs on operators, the Department of Conservation (Department) used a computational general equilibrium model of the California economy provided by the US Bureau of Economic Analysis (BEA) and known as the Regional Input-Output Modeling System II (RIMS II, 2007/2015). This type of input-output model does not consider, estimate, or speculate on changes in behavior on regulated entities. As such, it does not consider innovations operators may undertake to reduce costs, changes in scheduling of maintenance and testing so they occur simultaneously when a rig is on a well, or changes in oil and gas production that may be associated with taking wells on and off-line as they undergo testing required by the regulations. This analysis takes

[1] "What Drives Crude Oil Prices?" U.S. Energy Information Agency. <https://www.eia.gov/finance/markets/crudeoil/>
[2] "Crude Oil: California Crude Oil Price Fluctuations Are Consistent with Broader Market Trends, U.S. Government Accountability Office. <https://www.gao.gov/products/GAO-07-315>

estimated costs for each requirement and applies multipliers developed by the BEA to estimate the broader economic impacts (see the Economic Impacts section of this report).

The direct spending resulting from the proposed regulations is anticipated to amplify the economic impacts in the state of California with an increase in gross output, employment, earnings, and value added (see Table 2). Most of the positive economic impacts will affect the service contractors that provide the required testing, re-abandonment, and remediation work described in the proposed regulations. However, some of these impacts will be offset by operators that could reduce in-house jobs or exit the industry altogether if they cannot meet the regulatory cost burdens.

Table 2. Total Statewide Indirect Economic Impacts from Regulatory Spending

Economic Impact	Year 1	Year 2	Year 3	Year 4	Year 5
Gross Output	$301,558,461	$400,243,859	$211,865,175	$212,496,059	$212,049,967
Earnings	$90,436,866	$93,670,873	$62,095,594	$61,959,207	$61,680,684
Jobs	1,343	1,433	906	908	906
Value Added (GSP)	$188,807,492	$200,138,941	$135,426,360	$135,683,030	$135,502,659

However, the resultant environmental and public health benefits and the reduced liability to both the operators and the state should also induce an economic impact. One of the intended benefits resulting from the proposed regulations is the protection of groundwater. The prevention of groundwater contamination is much less resource-intensive than remediation efforts once groundwater has been contaminated. A U.S. EPA study of costs associated with groundwater contamination remediation at Superfund and RCRA sites estimates that the costs could rise to over $5 million per site. Moreover, in 2011, a workplace incident involving an unexpected sinkhole caused by cyclic steaming operations resulted in the death of an employee, loss of production for operators in the area, and substantial litigation. The proposed regulations will address workplace safety and attempt to prevent workplace harm going forward. Furthermore, the proposed regulations should reduce the risk of significant incidents to the operator that would lead to a stop in production, like surface expressions or groundwater contamination, which is key to maintaining profit margins in the short- and long-term (see the Benefits section of this report).

Introduction

All state agencies that propose major regulations must complete a SRIA as described in Government Code section 11346.36 and California Code of Regulations title 1, sections 2000 through 2004. For the purposes of the SRIA, a major regulation is one that will result in either total costs or benefits of more than $50 million in any given year of the proposed regulations' implementation.

This SRIA, prepared by the Division, analyzes the potential economic impact of a proposed regulatory framework for the oversight of the Division's UIC program. The potential economic impact of the proposed regulations meets the criteria to be considered "major" because the estimated costs exceed the $50 million total annual impact threshold.

As described in more detail below, most of the cost inputs for this analysis were obtained directly from oil and gas operators. To estimate the broader economic impact, multipliers provided by the BEA were used to generate final demand change in gross output, employment, earnings, and value-added for every dollar of direct spending. In order to avoid underestimating potential economic impacts, a conservative cost estimate approach was taken. Where there was any question as to whether or not costs incurred by operators could be attributed to the proposed regulations, for the purposes of this assessment, the Division opted to attribute them to the regulations.

Background

The Division supervises the drilling, operation, maintenance, and plugging and abandonment of oil, gas, and geothermal wells in California. The Division carries out its regulatory authority under a dual legislative mandate to encourage the wise development of oil and gas resources while preventing damage to life, health, property, and natural resources, including underground and surface waters suitable for domestic or irrigation purposes (see Pub. Resources Code, Section 3106). Among the types of wells that the Division regulates are wells used to inject fluids associated with oil and gas production, either for purposes of enhancing oil or gas recovery, or to dispose of brine, and other fluids produced from oil and gas zones, along with the hydrocarbons during extraction. Injection wells have been an integral part of California's oil and gas operations for nearly 60 years. In recent decades, enhanced oil recovery (EOR) injection methods have become the predominant method for hydrocarbon extraction used in California. About 75 percent of California's oil production is the result of EOR injection. Injection wells also function as a disposal method for the large volumes of water that are drawn up along with the hydrocarbons.

In addition to implementing California statutory mandates such as those found in Public Resources Code section 3106, the Division's regulations also implement the federal Safe Drinking Water Act pursuant to a primacy delegation from the United States Environmental Protection Agency (U.S. EPA). Enacted in 1974, the federal Safe Drinking Water Act directed U.S. EPA to develop federal standards for the protection of the nation's public drinking water supply. Section 1425 of the Safe Drinking Water Act allows states to obtain primary enforcement responsibility (often referred to as "primacy") for regulating the underground injection of fluids associated with oil and gas production through their own program of state authorities. A program for regulation of underground injection activities is often referred to as "underground injection control," or UIC. To obtain primacy, a state must demonstrate to U.S. EPA's satisfaction that its UIC program meets certain minimum requirements set forth in the Safe

Drinking Water Act and represents an effective program to prevent injection that endangers underground sources of drinking water (see 42 U.S.C., section 300h–4, subdivision (a)).

Once the U.S. EPA approves a state UIC program, the state has primary responsibility for regulating underground injection within its jurisdiction. In such cases, the state and U.S. EPA enter into a memorandum of agreement, which may include other terms, conditions, or agreements relevant to the administration and enforcement of the UIC program (see 40 C.F.R., section 145.25, subdivision (a)). In primacy states, U.S. EPA retains oversight and secondary enforcement authority, as well as the authority to revise or withdraw state primacy (see 42 U.S.C., section 300h–2, subdivision (a) and 40 C.F.R., section 145.33.)

In 1981, pursuant to section 1425 of the Safe Drinking Water Act, the Division applied for primacy to implement the Class II portion of the UIC program for the state of California (UIC Program). "Class II" is the classification U.S. EPA's regulations apply to wells that inject fluid associated with oil and gas production (see 40 C.F.R., section 144.6). The U.S. EPA granted primacy for the UIC Program to the Division through a memorandum of agreement, dated September 29, 1982 (Primacy Agreement).[3] While not itself a regulation, the Primacy Agreement describes the terms of the Division's UIC program as understood and approved by the U.S. EPA. Class II injection operations regulated under the Division's UIC Program include waterflood, steamflood, cyclic steam, water disposal, and other approved methods that enhance oil recovery, and injection to dispose of produced water.

The Primacy Agreement commits the Division to several regulatory objectives, including two-part mechanical integrity testing for injection wells, evaluation of other wells within a specified "area of review" around injection wells prior to regulatory approval of injection projects, and protection of underground sources of drinking water (generally, groundwater aquifers with water containing less than 10,000 milligrams per liter total dissolved solids). While the Division's existing UIC program requirements include an approval process, inspection, enforcement, mechanical integrity testing, plug and abandonment oversight, and data management, some objectives outlined in the Primacy Agreement were never fully actualized in the regulatory framework of the Division's UIC program.

Instead, the Division's existing UIC regulations, which have remained largely unchanged since the primacy delegation thirty-five years ago, sometimes require considerable case-by-case interpretation to identify appropriate project-specific requirements. Over time, this has led to a general lack of transparency and inconsistent application of requirements, and in some cases, aging regulatory constructs that have not kept pace with changing oil production methods and advancements in the understanding of threats to health, safety, and the environment.

The Division began to address these issues within the UIC Program in earnest in 2009 when Division management initiated a review of then-current practices for approving injection projects, annual project reviews, and the evaluation of wells within the area of review. In addition to the internal review, the Division's UIC program came under scrutiny by both the Legislature and the U.S. EPA.

[3] As referenced in the Primacy Agreement, U.S. EPA's grant of primary authority to the Division to administer the Class II portion of the Underground Injection Control program in California became effective on March 14, 1983.

In the 2010 budget, the Division requested and received additional staff to support the UIC Program. As part of the Annual Budget Act, Senate Bill 855 (Chapter 718, Statutes of 2010) was passed by the Legislature. SB 855 required the Division to report annually on a variety of issues related to the UIC program, more specifically, project approval letters (PALs), permit violations, shut-in orders, UIC Program staffing, and any State or federal legislation, administrative, or rulemaking changes. The following year, the U.S. EPA took a harder look at the UIC Program by requesting a review and evaluation of the Division's UIC Program for compliance with the Primacy Agreement. In response, a comprehensive report was prepared and made available by a third party in June 2011 (Horsley Witten Report[4]). The report provided recommendations and objectives to improve the UIC program. In 2015, Senate Bill 83 (Chapter 24, Statutes of 2015) extended, and added to the reporting requirements outlined in SB 855.

In 2015, the Division developed a "Renewal Plan"[5] that reflected efforts to overhaul the UIC Program. The objectives of the regulatory overhaul were based on the Division's own evaluation of its UIC Program, concerns raised by the Horsley Witten Report and other analyses, and input from stakeholders and other regulatory agencies. In addition to emphasizing the protection of public health and the environment, the overhaul would help better ensure that the UIC Program satisfies the expectations outlined in the Primacy Agreement.

Statement of Need

The existing UIC regulations cover Class II wells broadly and have not been updated to reflect current field practices. Today's injection wells represent a unique and modernized set of techniques and standards that require specific regulations to avoid health and safety risks. The proposed regulations reflect the necessary updates and include specificity for:

- Project data requirements, including casing diagrams, injection fluid analyses, and monitoring system information;
- Evaluation of wells within the area of review;
- Filing, notification, operating and testing requirements;
- Mechanical integrity testing (MIT);
- Maximum allowable surface pressure and step-rate tests;
- Surface expression prevention and response;
- Surface expression containment;
- Universal operating restrictions and incident response; and
- Monitoring and evaluation of seismic activity.

The proposed regulations represent a precautionary, rigorous approach to bring the UIC regulations up-to-date and to prevent, as far as possible, damage to life, health, property, and natural resources.

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[4] Horsley Whitten Group, Final Report, *California Class II Underground Injection Control Program Review*, June 2011. <http://www.conservation.ca.gov/dog/Documents/DOGGR%20USEPA%20consultant%27s%20report%20on%20CA%20underground%20injection%20program.pdf>

[5] Department of Conservation, *Renewal Plan, Oct.* 2015. <http://www.conservation.ca.gov/dog/Pages/RenewalPlan.aspx>

Public Outreach and Input

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

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

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

As discussed herein, the Division also surveyed operators and industry groups for input on the direct cost estimations used for this SRIA.

Baseline

As previously stated, this regulatory package was developed as part of a series of activities designed to modernize the Division's administration of California's UIC program. This modernization started with external and internal reviews of the UIC program, and additional resources and oversight enacted by the California State Legislature. Additional staff was added and extensive training was implemented to improve the ways in which projects are reviewed, remediated, and monitored to move more projects towards full compliance.

As the Division has implemented improved review and enforcement procedures, new UIC projects have been subject to greater scrutiny and stricter adherence to the existing regulations. On October 7, 2015, the Division issued a notice to all operators informing them that the Division would be conducting a project-by-project review of every existing UIC project in the state for compliance with regulations, completion of testing requirements, and adherence to limitations specified in PALs. The notice indicated that the Division would work closely with the State Water Resources Control Board (Water Board) to evaluate and ensure that there is effective containment of injected fluids in each UIC project. The higher level of scrutiny means that the Division is collecting more detailed data on a project-specific basis that goes beyond the existing requirements.

The Division also receives comprehensive data on UIC projects through the aquifer exemption process, independent of the existing UIC regulations. Under the Safe Drinking Water Act, injection into an aquifer with water containing less than 10,000 milligrams per liter total dissolved solids is not permitted unless an aquifer exemption has been approved by the U.S. EPA. The aquifer exemption process requires substantial data gathering and analysis by the Division, which is necessary to conduct a thorough review of an aquifer's geological, chemical, engineering and current use information. The evaluation of the data determines if the aquifer meets state and federal criteria for exemption. As a result, UIC projects in an area covered by an approved aquifer exemption benefit from a comprehensive data set that already addresses some of the requirements of the proposed regulations. The submitted data include information such as:

- Detailed mapping of currently exempt areas and zones based on the presence of hydrocarbons;
- Depths, locations and current use of water wells;
- Geological, vertical and lateral confinement/containment features in the reservoir (e.g., faults, pinch-outs, shales);
- Engineering analyses of confinement/containment due to pressure and hydraulic gradients;
- Geochemical analyses of injection zones and fluids;
- Information about oil wells and water supply wells near the aquifer; and
- Other geologic and engineering information relevant to future projects in a digital format.

The baseline for this analysis assumes that injection project operators, without the enactment of the proposed regulations, would – at minimum – be in compliance with existing regulatory requirements, comply with conditions imposed by the Division issued as part of the project-by-project review, recently approved PALs, and perform such activities as may be required to ensure that injection fluids are confined to the intended zone of injection. Consistent with its statutory authority, the Division is already imposing project-specific approval conditions for some UIC projects requirements that are substantively similar to some of the proposed regulatory requirements. This functional overlap likely reduces the actual cost impact of the proposed regulations on operators with existing PALs. However, since the review and imposition of higher standards is being conducted on a project-by-project basis as needed until the proposed regulations are finalized, this economic analysis takes a conservative approach and assumes that operators have complied with existing orders and currently enacted regulations only.

The baseline used in this analysis is the existing regulatory requirements for UIC projects that will be expanded, clarified, or replaced by the proposed regulations. The relevant existing regulations are discussed in context in the Estimating Direct Costs section and describe where the proposed regulations may impose additional costs over and above the current regulations.

Estimating the Direct Costs

Methodology

To estimate the direct costs of compliance with the proposed regulations, the Division divided the proposed regulatory requirements into discrete actions that operators will need to undertake if the regulations are implemented as proposed. Most of the individual requirements were translated into an online survey (see Appendix A that was disseminated to operators via the oil and gas trade associations that are active in California – the Western States Petroleum Association (WSPA), the California Independent Petroleum Association (CIPA), and the Independent Oil Producers Association (IOPA) as well as the Conservation Committee of California Oil and Gas Producers (CCOGP).

Many of the requirements provide flexible, case-by-case compliance options allowing operators to propose alternative means of compliance. This analysis, unless indicated otherwise, conservatively assumes that operators will be required to comply with the costliest alternative even though operators would likely propose more cost-effective means to meet the requirement in many cases. In other instances, where the Division changed the regulations such that a requirement was materially altered, the Department relied on a combination of operator input and Division engineering staff expertise to estimate the cost. The process for developing the cost estimates is described in the discussion of each of the new regulatory components below.

Of the approximately 144 operators who have active UIC wells, 17 operators responded to the survey. Respondents included two operators with fewer than 10 wells, seven operators with 10-100 wells, four operators with 101-500 wells, and four operators with over 500 wells. Survey respondents are skewed towards larger UIC operators, with eight of the 17 operators, or 47 percent, owning more than 100 UIC wells. Among the population of UIC operators, the total percentage of operators with more than 100 UIC wells is approximately 13 percent, yet, these operators own more than 95 percent of the state's UIC wells. For this reason, Division experts treated survey respondents and their responses as representative of the statewide population of UIC operators.

As some of the proposed regulatory requirements are consistent with operators' current testing or data collection activities, the survey not only asked for cost estimates for the regulatory requirements, but also, to what extent, the operator already complied with the proposed requirements. Where a particular requirement provided options as to how an operator could comply, the survey also asked operators to estimate what method of compliance they would be likely to use. The various costs that were provided by operators were then averaged into either a weighted average or a full-cost average, where applicable. In cases where a specific cost estimate differed dramatically from the estimates provided by other operators, these outliers were removed from the average calculation. For example, one operator, who included sarcastic remarks in the comments' section of the survey, provided several cost estimates that were orders of magnitude larger than the other operators.

The costs of each of the various requirements as indicated by industry survey respondents or estimated by the Division engineering staff are broken down in Table 3.

Table 3. Regulatory Cost Drivers

Section of Proposed Regulation	Direct Cost Input	Existing Project or Well Cost	New Project or Well Cost
1724.7(a)(1)(B)	Map of Area of Review[a]	$5,711	$7,542
1724.7(a)(1)(B)(iii)	Map of underground disposal horizons, mining, and other subsurface industrial activities[a]	$2,461	$4,102
1724.7(a)(1)(C)	Compendium of information on wells in Area of Review[a]	$5,471	$9,300
1724.7(a)(1)(C)(iii) and 1724.7.1	Casing Diagrams[b]	$750	$750
1724.7(a)(2)(A)	Reservoir Characteristics[a]	$4,221	$14,350
1724.7(a)(2)(B)	Reservoir Fluid Data[a]	$4,838	$9,917
1724.7(a)(2)(C)	Structural Contour Map[a]	$6,933	$14,232
1724.7(a)(2)(E)	Two Geologic Cross Sections[a]	$6,990	$9,570
1724.7(a)(2)(F)	Electric Log[a]	$3,988	$7,974
1724.7(a)(3)(H); 1724.7.2; and 1724.10(d)	Fluid Analysis[a]	$2,392	$3,986
1724.7(c)	Electronic data submittal/data formatting[a]	$35,069	$35,069
1724.8(a)(2)	Re-abandon P&A wells that don't meet standard[a]	$52,125	$173,750
1724.10.3	Step-Rate Tests[b]	$23,321	$27,321
1724.10(e)	Chemical Disclosure[a]	$1,000	$1,000
1724.10(f)	Pressure Monitoring & Recording Device[b]	$2,100	$2,100
1724.10(h)	Tubing and Packer[b]	$39,500	$39,500
1724.10(m)	Cyclic Steam Record Retention[a]	$3,000	$3,000
1724.10.1	MIT Part One - Casing Pressure Test[b]	$10,871	$10,871
1724.10.2	MIT Part Two - Fluid Migration[b]	$5,579	$5,579
1724.11	Surface Expression Prevention[b]	$120,000	$420,000

Note: Existing costs may differ from new costs when costs for existing projects or wells represent the remaining average cost to bring the project or well into full compliance (i.e., a weighted average); whereas the costs for new projects or wells represent the full amount to bring the project or well into full compliance.

[a] Per project cost.

[b] Per injection well cost.

Some of the requirements have a per project cost while others have a per well cost. Additionally, existing costs may differ from new costs when costs for existing projects or wells represent the remaining average cost to bring the project or well into full compliance (i.e., a weighted average); whereas the costs for new projects or wells represent the full amount to bring the project or well into full compliance.

Proposed regulatory requirements and costs vary based on the type of well and how a particular well is constructed. Where appropriate, costs are only applied to a subset of wells or projects or wells impacted by the new requirements.

Population of Wells Subject to Proposed Regulations

According to Division records, there are a total of 765 active projects and over 56,000 wells coded as UIC wells. UIC well types include cyclic steam, steam flood, waterflood, pressure maintenance, waste disposal, air injection, and gas injection wells. However, for the purposes of estimating the costs, the Division is only counting active injection wells that have a record of injection within the past six years. This reduced the population of UIC wells to 37,563, as of December 5, 2017.[6] Wells that are inactive for over 24 months are considered idle and will be subject to idle well regulations rather than UIC well regulations. However, the Department opted to include a larger subset of wells in order to account for the possibility that increasing oil prices, and recently proposed revisions to existing regulations governing the testing and management of idle wells, may result in some idle wells being returned to production or new wells being drilled.

The analysis estimates the costs of compliance over the first five years of the proposed regulations' effective date. To this end, the Department had to estimate the number of new projects per year over that timeframe. Since the year 2000, an average of 18 new projects per year were issued PALs by the Division. For purposes of estimating the costs, the number of projects increase by 18 projects per year. Division records indicate that over the last 17 years there has been an average net increase of 716 new UIC wells per year. The change in number of wells is applied to those costs that need to be calculated on a per well basis for Years 2 through 5 of implementation.

To ensure a conservative estimate that represents a full consideration of possible costs, this analysis, unless otherwise specified, estimates costs assuming operators comply with the specific, default requirements stated in the proposed regulations. It does not capture potentially less costly approaches to compliance that could be proposed by operators and approved by the Division on a case-by-case basis to meet the general requirements of the proposed regulations. As a result, this analysis likely reflects an overestimate of the economic impacts of these proposed regulations.

[6] This well count represents a snapshot of wells taken on December 5, 2017, and changes on a daily basis.

Direct Cost Inputs

1. Definitions and Approval of Underground Injection Control Project

The first two sections of the proposed regulations consist of definitions and a description of the permitting process. Both of these sections are clarifying in nature and do not impose additional costs on operators. The first additional costs imposed by the proposed regulations are in new data requirements that will be standard for all UIC projects.

2. Project Data Requirements

Proposed section 1724.7 specifies the information operators of injection projects must provide the Division to facilitate the Division's review of proposed and existing injection projects. Division staff anticipates that operators will come into compliance with all project data requirements over the first two years of implementation of the regulation as project files are reviewed and data to complete the files are requested. In the cost tables below, this results in a spike in costs the second year because the first year includes half of all existing projects and the second year includes both new projects and the remainder of existing projects.

a. Engineering Study

Proposed section 1724.7, subdivision (a)(1) requires an engineering study to demonstrate that injection fluid will be confined to the approved injection zone, and that the project will not cause damage to life, health, property, or natural resources. The costs of this engineering study are broken down into the delineated components described below.

i. Map of Wells in Area of Review

The first cost inducing element of the engineering study, proposed subdivision (a)(1)(B) requires a map of wells, including water wells, and other features within the area of review. Operators are also required to include a compendium of information about the wells and features on the map. The majority of operators (83 percent) indicated that they already had the information they needed to fully or partially comply with this requirement. As a result, the average weighted cost provided by respondents on a per project basis was $5,311. The average cost for new projects is higher, at $7,542 because operators are unlikely to already have the data necessary to comply. The total statewide direct costs for project data requirements are depicted in Table 4. The cost estimate assumes that half of operators will update or create their maps within the first year of the regulations, and the remainder will do so upon review of project files by the Division. As a result, half of the total direct cost is attributed to the first year with the remainder taking place in the second year. Subsequent revisions to these maps for existing projects will have very minor costs. The costs in Years 3 through 5 include the costs for creating maps for newly proposed projects.

ii. Map of Underground Disposal Horizons

Approximately 44 percent of the responding operators indicated that they already had the data necessary to meet the requirement in proposed subdivision (a)(1)(B)(iii). The subdivision requires that the map of the area of review include any underground disposal horizons, mining, and other subsurface industrial activities not associated with oil and gas production within the area of review, to the extent such information is publicly available or otherwise known to the operator. Operators indicated that for existing projects the average weighted cost would be $2,461 and for new projects it would be $4,102. As with other requirements, this analysis assumes that half of the existing projects would come into compliance the first year and the remaining projects would come into compliance the second year. For Years 2 through 5, it is assumed that 18 new projects will be permitted annually. While this is part of the map of the area of review, because it is a unique requirement, this cost is separated from the map of area of review costs and has its own row in Table 4.

iii. Compendium of Information of Wells in Area of Review

Proposed subdivision (a)(1)(C)(i) requires operators to provide specified information about all the wells in the area of review. Most of the operators (89 percent) indicated that they already had the information required in this section. On average, operators estimated that it would cost them $5,471 to acquire and compile this information on their projects. For new projects, the cost is estimated to be $9,300 because new data will need to be created. Just as with the maps, this analysis assumes that half of the existing projects will come into compliance in the first year, with the remainder coming into compliance in the second year. Year 2 includes costs for 18 new projects. For Years 3 through 5, the costs shown in Table 4 only apply to new projects. Updating the information in existing projects after initial compliance is achieved will yield very little cost.

iv. Casing Diagrams

Proposed subdivision (a)(1)(C)(iii) requires operators to provide a casing diagram that meets the requirements of proposed section 1724.7.1. Subsequent to the creation and distribution of the survey and receipt of the survey results, the Division revised the casing diagram requirements to provide more flexibility and clarity. As a result, Division engineering staff determined that the average cost provided by operators ($2,061), was far too high. Whereas the discussion draft required that well casing diagrams be submitted as both a graphical diagram *and* a flat file dataset, the proposed regulations in section 1724.7.1, subdivision (e) state that “In lieu of graphical casing diagrams, operators may satisfy the requirements of section 1724.7(a)(1)(C)(iii), by submitting a flat file data set containing all of the information described in this section.” Therefore, this analysis assumes that only operators who already have graphical casing diagrams will submit them. The remaining operators will take the less costly compliance option. As a result, Division engineering staff recommended using an estimate of $750, which coincides with the median value indicated in the operators’ responses. Just over one quarter of wells (27 percent) were estimated by operators to not have casing diagrams. Just as with the prior estimates, this assumes that half of the remaining casing diagrams or the data to meet the requirement will be created and submitted in each of the first two years. In Table 4, Years 2 through 5 add 716 wells per year. Years 3 through 5 include only newly drilled wells or wells brought back online that do not currently have casing diagrams.

Table 4. Total Statewide Costs for Project Data Requirements: Engineering Study

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	$2,184,458	$2,320,208	$135,751	$135,751	$135,751
Map of underground disposal horizons, mining, and other subsurface industrial activities	$941,333	$1,015,169	$73,836	$73,836	$73,836
Compendium of information on wells in Area of Review	$2,092,658	$4,352,715	$167,400	$167,400	$167,400
Casing Diagrams	$3,803,254	$4,340,254	$537,000	$537,000	$537,000
Total	**$9,021,701**	**$12,028,346**	**$913,987**	**$913,987**	**$913,987**

b. Geologic Study

Proposed section 1724.7, subdivision (a)(2), requires a geologic study for each injection zone. The geologic study must include:

i. Reservoir Characteristics of Each Injection Zone

The first cost imposed by the geologic study is the submittal of reservoir characteristics information. This section is largely a reorganization of current regulations. Under the proposed regulations, the reservoir characteristics' requirement would be moved from the engineering study to the geologic study (existing subdivision (a)(2) to proposed subdivision (a)(2)(A)). Proposed subdivision (a)(2)(A) would also add language clarifying the scope of the geologic characterization in order to improve data quality and consistency. Specifically, the new language reads, the "scope of the geologic characterization shall encompass the reservoir rock, caprock and sealing mechanisms, the injection zone including the vertical interval above and below the approved injection zone, and the areas where potential migration of fluid or entrapment of migrated fluid could occur."

Nearly all of the responding operators (94 percent) indicated that this would not impose any additional cost on them. As a result, the average weighted cost ended up being relatively low at $4,221. For new projects, where operators would not necessarily have the data to comply with this requirement, the survey responses indicated that producing the reservoir characteristics would cost, on average, $14,350. One respondent who indicated that it would cost them $800,000 was not used to calculate the average because it was not remotely consistent with estimates provided by other operators. The total statewide cost of this requirement is shown in Table 5. As with the other requirements, the cost of implementation was divided over the first two years and only new projects were included in Years 3 through 5.

ii. Reservoir Fluid Data

Another provision that was moved and expanded upon is the requirement for reservoir fluid data. In the proposed regulations, this section would be moved from the engineering study to the geologic study (existing subdivision (a)(3) to proposed subdivision (a)(2)(B)). Proposed subdivision (a)(2)(B) would also add non-hydrocarbon components in associated gas to the parameters for reservoir fluid data and specify how water quality analysis would be conducted. This additional information is relevant to protecting public health and safety because certain non-hydrocarbon components such as hydrogen sulfide can be very dangerous when inhaled. Eighty-three percent of responding operators indicated that they would already be able to fully or partially comply with the expanded requirements on fluid analysis with most operators indicating that the changes to the regulations would result in no additional cost. As a result, the average weighted cost indicated by the responding operators was $4,838 per project. For new projects this cost increases to $9,917 per project as operators would have to collect new information to meet the requirement rather than relying on data they already acquired in the exploration and production process for existing projects. The total statewide costs are shown in Table 5.

iii. Structural Contour Map

The requirement for a structural contour map, like the previous requirement, would be retained as part of the geologic study and renumbered as proposed subdivision (a)(2)(C). New language would also be added to specify that faults and lateral containment features that are important in the evaluation of zonal isolation be identified. The new language is intended to clarify the scope of the requirement and to result in better quality, more consistent data for injection projects. Ninety-four percent of respondents indicated that they could already partially or fully comply with the expanded requirement with 8 of the 17 respondents indicating that it would impose no additional cost. The remainder, on average (again, excluding the dramatic outlier), indicated that the expanded requirement would cost them $6,933 per UIC project. Creating contour maps for new projects would cost approximately $14,232 for each new project. The Division estimates that those existing projects that do not already have an adequate contour map, will come into compliance over the first two years after the regulations are enacted as the Division evaluates project files. The total statewide costs are shown in Table 5.

iv. Isopach Map

The creation of isopach maps required in subdivision (a)(2)(D) does not impose any additional costs over what is required in current regulations. It simply changes the terminology from “isopachous” to “isopach.”

v. Geologic Cross Sections

Current regulations require at least one geologic cross section be part of the geologic study. The proposed regulations renumber the requirement to proposed subdivision (a)(2)(E). The requirement would also be modified and expanded to require at least two cross sections in the area of review with each cross section including at least three wells, including one injection well. This is an augmentation of the existing regulations. Current UIC regulations only require a single cross section and that the cross section be through at least one injection well. Cross sections are used to verify the geologic interpretation of the field, and requiring at least two cross sections and including additional wells in each cross section would enable greater confidence in the geologic interpretation of the field and injection zone. The increase in both the number of cross sections and number of wells included in each cross section is intended to result in better quality and more reliable project data resulting in more informed project evaluations. Ninety-four percent of operators indicated that they could already partially or fully comply with a version of this requirement that would require at least one geologic cross section in the area of review through at least three wells, including one injection well.[7] Nine of the 17 respondents indicated that it would have no additional cost for them. The average weighted cost per project to meet this requirement (again, excluding the operator who consistently provided exceptionally high estimates), ended up being $2,205. And because operators indicated that the full cost of one geologic cross section is $4,785 per project, the Division estimates that the full cost for each existing project to comply with this requirement is $6,990 per project. The Division estimates that all projects will become compliant within the first two years of implementation while the Division reviews project files as part of their ongoing project-by-project review. Operators indicated that meeting this proposed requirement for new projects would cost approximately $9,570 for each of the estimated 18 new projects in Years 2 through 5. The total statewide cost estimate for all 765 projects and the 18 new annual projects is shown in Table 5.

vi. Electric Log

Like the cross-sections requirement, the representative electric log is currently required as part of the geologic study, but renumbered as proposed subdivision (a)(2)(F). The requirement would also be modified by including USDWs (if any) among the features that must be identified in the log. Adding this feature to the log requirement is necessary to yield more useful project data and enable the Division to fulfill its statutory responsibility to protect USDWs from endangerment. Eighty-nine percent of responding operators indicated that they could fully or partially meet this expansion of the cross-section requirement and nine of the seventeen responding operators indicated that it would present no additional cost for them. Based on survey responses, the average weighted cost of this requirement was $3,988 per project. For new projects, this amended requirement would cost operators approximately $7,974. As with other project data requirements, the Division anticipates that operators will come into compliance within the first two years of the regulations taking effect as project data files are reviewed for compliance. The statewide estimate cost can be found in Table 5.

c. Injection Plan

Proposed section 1724.7, subdivision (a)(3)(A) through (H), requires an injection plan that, for the most part, would not impose additional costs on operators because they simply involve statements from the operator about their plans for the proposed project. The injection plan, method of injection, identification of wells, identification of the source of injection fluids, a map showing injection facilities, a monitoring system, and proposed cathodic protection measures are all things that would help the Division better understand a project. However, they are either part of existing regulations or would be necessary for an operator to already know when they conceived of a potential project that they anticipate will be economical or to meet PAL requirements.

[7] The cost survey was distributed with the Discussion Draft Version 2 (June 2017) that expanded the current requirement to the following: "At least one geologic cross section in the area of review through at least three wells, including one injection well."

The portion of the injection plan that would impose additional costs for some projects is proposed subdivision (a)(3)(F) requiring injection fluid analysis, which is covered included in the cost estimates for fluid analysis below.

i. Monitoring System

As part of the injection plan, the requirement for a monitoring system under existing subdivision (c)(3) would be retained and renumbered as proposed subdivision (a)(3)(F). The proposed subdivision would also add a requirement for operators to consult with the Water Board or the appropriate Regional Water Quality Control Board (Regional Water Board), collectively referred to as Water Boards, in the event the Division or the Water Boards require groundwater monitoring in relation to the project. The Water Boards have their own mandate to protect groundwater resources from degradation, and they review underground injection projects pursuant to a memorandum of agreement with the Division. If the Water Boards conclude that groundwater monitoring is necessary, then the Division defers to the Water Boards' judgment and expertise and expects the operator to consult with the Water Boards regarding the specific parameters of a groundwater monitoring program. The proposed regulations would codify this existing practice and anticipate continuing to incorporate any groundwater monitoring programs as conditions of project approvals. In many cases this could involve a requirement for monitoring. As such, under existing practice, monitoring could be required and this provision does not impose additional costs on operators.

ii. Cathodic Protection Measures

Proposed subdivision (a)(3)(G), "a list of proposed cathodic protection measures," is consistent with existing requirements. It has been renumbered from existing subdivision(c)(5), so it does not impose an additional cost.

d. Data Supporting Determination of Maximum Allowable Surface Pressure

Data from step rate tests are used to determine the fracture gradient of the injection zone and the appropriate Maximum Allowable Surface Pressure (MASP) for an injection project. An appropriate MASP helps ensure that injection pressures will not damage confining layers of the underground formation and be the cause of fluid leaving the approved injection zone. Ensuring that fluid remains in the approved injection zone is a key performance standard of the Division's regulatory program for underground injection operations. The migration of fluid of varying quality between different underground formations can be detrimental to both protected groundwater resources and hydrocarbon resources.

The Division's current regulations, at section 1724.10, subdivision (i), already provide that a step rate test "shall be conducted prior to sustained liquid injection" unless the Division determines that surface injection pressure for a particular well will be maintained considerably below the estimated "pressure required to fracture the zone of injection or the proposed injection pressure, whichever occurs first." Historically, however, the Division has inconsistently applied the requirement for step rate test data, and sufficient data is lacking for many existing injection projects. As a result, the Division has concerns that the MASPs for many existing injection projects are not based on relevant field data and may not be reflective of the actual fracture gradient of the injection zone. This is reflected in the survey responses in which 58 percent of the responding operators indicated that they would have the necessary data to meet this requirement. Proposed section 1724.7, subdivision (a)(4) would explicitly confirm that step rate test data supporting the requirements determining the MASP in section 1724.10.3 or similar data to inform the fracture gradient, is required for each injection well in the underground injection project.

The proposed regulations would establish a default requirement that step rate tests be performed on all injection wells that are part of a project, using step rate test procedures specified in proposed section 1724.10.3. This default approach of performing step rate tests on all injection wells in a project using the test parameters of proposed section 1724.10.3 will not be necessary for most projects. Depending on project specific factors such as the location of injection wells and relative homogeneity of the injection zone, representative step rate test data from select wells within the project will be sufficient to establish a conservative estimated baseline fracture gradient for the entire project. Accordingly, the proposed subdivision would allow operators to submit a detailed plan in the event they wish to deviate from the specified test procedures and/or perform step rate tests on less than all injection wells in the project. The alternative plan, which would be subject to the Division's approval, would reduce compliance costs in circumstances where operators can demonstrate that equally reliable data can be generated using other means.

Using this flexibility, Division staff estimates that, on average, each project will likely have to conduct a step rate test or other equivalent test on approximately 3 wells per project. The average costs for a step rate test provided by operators (excluding two outliers that were dramatically different than all other estimates) was $27,321 per well. Division staff estimates that approximately 364 of the 765 active projects may need to re-establish or verify the fracture gradient because they may have previously relied on modeling, estimates from nearby projects, or the Division permitted the project using a standard value fracture gradient value that did not rely on site specific analysis. The figures in Table 5 show half of the 364 projects undergoing three step rate tests over each of the first two years and all 18 new projects having three step rate tests going forward.

e. Other Project Data Requirements

The proposed regulations would reflect a new numbering for existing section 1724.7, including the requirement for operators to provide copies of notice letters sent to offset operators. An offset operator is any known operator of an oil or gas well in the immediate area surrounding the proposed project or well. Other than new numbering, the text of this requirement would be unchanged and would not impose any additional costs.

Additional regulations revise the existing provision that explains the Division's authority to require additional data as may be necessary. The revisions do not change substantive requirements, but would more accurately describe the Division's authority. Specifically, the new language would explain that the Division may require additional data for any injection project that "are pertinent and necessary for proper evaluation of the underground injection project," not just "large, unusual, or hazardous" projects. The amendments promote transparency and accurate expectations regarding potential data needs, but do not impose additional costs on operators of underground injection projects because it merely describes the Division's existing authorities. The listed items that could be requested as part of an information request are examples that do not necessarily reflect additional cost drivers or requirements.

Proposed subdivisions (b) and (c) would provide administrative amendments regarding when and how the Division must be provided data. For example, proposed subdivision (b) would require operators to provide any new and relevant data when adding a new well to the injection project. These provisions are intended to improve the quality and completeness of data the Division uses to evaluate injection projects, and to promote administrative efficiency in the Division's data gathering and management practices. These provisions do not impose any additional costs and the Division is already working with operators on this transition and has begun requiring data to be submitted in specific formats under their existing authority.

Operators responding to the survey indicated that the requirement to provide all data in a digital format specified by the Division would be costly. Only 24 percent of responding operators indicated that they had all of the information necessary to meet all of the project data requirements in a format that could meet Division standards. On average, operators estimated that it would cost them approximately $35,069 per project to convert their data into a format acceptable to the Division. This analysis assumes that operators will develop new data management practices to create data to meet Division requirements. While in the longer term developing consistent industry-wide data format requirements will likely save operators money, in the near term they will incur significant costs. As with the other requirements, the costs imposed to update data are likely to be spread over the first two years of implementation of the regulations as projects are reviewed by the Division.

Proposed subdivision (d) would add a requirement for data to be submitted under a cover letter bearing the names and signatures of the individuals responsible for preparing the data submission. The cited code sections in the Business and Professions Code and the resulting regulations are current law and this requirement is a reminder to operators and oil and gas service providers. The relevant code sections are generally enforced by the Board for Professional Engineers, Land Surveyors, and Geologists. Current statutes and regulations require certain data to be prepared and certified by a licensed professional. The Division often receives data without indication of the professional who prepared and certified the data, even though the data appears to require preparation by a licensed professional.

Finally, proposed subdivision (e) adds language intended to preserve, within specified parameters, the Division's existing discretion to make case-by-case determinations regarding the acceptance of alternative data. While the data requirements of proposed section 1724.7 are intended to be appropriate for the vast majority of injection projects, the Division finds it necessary and appropriate to retain limited flexibility when evaluating the sufficiency of data submissions. This does not impose any additional costs on operators.

Table 5. Total Statewide Costs for Project Data Requirements: Geologic Study, Fluid Analysis, and Step-Rate Tests

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Reservoir Characteristics	$1,614,533	$1,872,833	$258,300	$258,300	$258,300
Reservoir Fluid Data	$1,850,535	$2,029,041	$178,506	$178,506	$178,506
Structural Contour Map	$2,651,873	$2,908,049	$256,176	$256,176	$256,176
Geologic Cross Sections	$2,673,511	$2,845,756	$172,245	$172,245	$172,245
Electric Log	$1,525,410	$1,668,942	$143,532	$143,532	$143,532
Fluid Analysis	$934,870	$1,006,618	$697,550	$697,550	$697,550
Step-Rate Tests	$14,917,266	$16,392,600	$1,475,334	$1,475,334	$1,475,334
Electronic data submittal/formatting	$13,413,893	$13,413,893	$0	$0	$0
Total	**$39,581,890**	**$42,137,730**	**$3,181,643**	**$3,181,643**	**$3,181,643**

3. Casing Diagrams

Proposed section 1724.7.1 would specify the information that must be included in casing diagrams required under proposed section 1724.7. Ensuring that injection fluid will be confined to the approved injection zone is a key performance standard by which the Division evaluates injection projects. When an injection well or injection project is being proposed, other wells within the area of review that penetrate the injection zone could potentially serve as conduits for fluid migration, and must therefore be evaluated for integrity and other conditions. Casing diagrams can give the Division critical information to evaluate the wells within the area of review for a project.

Although casing diagrams are an existing data requirement for injection projects, the Division's existing regulations do not specifically identify much of the information that the Division finds necessary to properly evaluate the wells within the area of review. As a result, the casing diagrams submitted in connection with many injection projects are not consistent with industry standards. The Division therefore has ongoing concerns about wells within the area of review for many injection projects.[8] The costs associated with this section are covered in the previous section on Project Data Requirements and included in Table 4.

4. Fluid Analysis

Existing regulations require that operators provide the "source and analysis of the injection liquid." The proposed regulations expand and add specificity to this requirement by detailing the testing requirements, including tests for additives, total dissolved solids, temperature, and other constituents of the fluid being injected, as specified in proposed section 1724.7.2. The testing shall be made and filed with the Division whenever the source of injection fluid is changed or an additional source is introduced, and as requested by the Division. Proposed section 17247.2 requires that sampling take place after any additives are introduced, and requires that the analysis be conducted by a laboratory certified by the State Water Resources Control Board.

Despite the expanded and more explicit requirements, 89 percent of the respondents indicated that they already had the data necessary to partially or fully comply with the requirements. The average weighted cost of the fluid analysis was $2,392 per existing project and $3,986 for new projects. The cost of fluid analysis is explicitly imposed in three places within the regulations. First, an operator is required to analyze the reservoir fluid (proposed section 1724.7, subdivision (a)(2)(B)) as part of the original project approval; second, in proposed section 1724.7, subdivision (a)(3)(H), the operator must identify the source of the fluid and provide an analysis; and third, the operator must provide an analysis whenever the source of the injected fluid is changed (proposed section 1724.10, subdivision (d)). According to Division staff, aside from commercial disposal wells, operators do not change source water frequently. The staff estimates that commercial water disposal wells change water source every year whereas a more typical project would change water source not more than once every five years.

As a result, this analysis assumes that all projects will need to provide a fluid analysis of their projects when the Division proceeds with the project by project review over the first two years following the regulations taking effect. Therefore, the cost of $2,392 is applied to half of existing projects in Year 1 and half of existing projects in Year 2. The $2,392 cost is an average cost that includes estimates of $0 from operators who believe their sampling data will meet the proposed requirements. For commercial water disposal wells, the cost of a new analysis ($3,986) is applied every year. Finally, because Division staff estimates that, for existing projects, the cost of a new analysis should be applied once every five years, one fifth of all wells are assumed to be subject to a cost of $3,986 every year. The table also includes the assumption of 18 new projects per year. Total statewide costs for this requirement are shown in Table 5.

5. Evaluation of Wells within the Area of Review

Part of ensuring that underground injection projects do not cause damage to natural resources (including both USDWs and hydrocarbon resources) is evaluating potential mechanisms that could lead fluid to migrate outside of the approved injection zone. Fluid migration between different geologic

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

zones can be a problem when low quality or contaminated fluid enters higher quality groundwater (including USDWs), or when unwanted fluid enters hydrocarbon reservoirs. In order to protect USDWs and other zones from injection fluid, the Division evaluates whether other wells within the area of review for the injection project have the potential to act as vertical conduits for fluid migration. This potential may arise depending on the condition of the wells within the area of review, and can be of particular concern for idle or poorly abandoned wells that lack the internal fluid pressure that could otherwise help repel the entry of external fluid.

Proposed section 1724.8 would make explicit the performance standard that injection projects not cause or contribute to the migration of fluid outside the approved injection zone. Proposed subdivision (a)(1) would also explain how certain wells within the area of review will be evaluated, and would indicate that some wells may require additional testing or logging in order to provide the requisite assurances that such wells will not act as conduits for fluid migration. This cost is included in the estimate for the project data requirements in proposed section 1724.7, subdivision (a)(1)(C), which requires operators to provide a compendium of information about wells in the area of review.

Additionally, proposed subdivision (a)(2), would make clear that plugged and abandoned wells within the area of review must be in a specified condition – namely, have cement across all perforations and extending at least 100 feet above certain points identified in the proposed regulations. Wells that are not abandoned in the specified condition will need to be addressed, either through physical work to meet the standard, or through ongoing monitoring to detect potential fluid migration. The Division will not approve injection that has the potential to result in fluid migration outside of the approved zone, and operators will be required to take any steps that may be necessary to provide assurances of fluid confinement. This requirement is consistent with current practice by the Division and current abandonment standards. The requirement to re-abandon or remediate wells within the area of review is commonplace as a condition of approval. Additionally, existing abandonment requirements in existing regulations section 1723.1 already requires that when wells are plugged and abandoned, they must have cement from at least 100 feet below the bottom of each oil or gas zone, to at least 100 feet above the top of each oil or gas zone as well have cement across all perforations and extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest. Nonetheless, Division engineers anticipate that as the regulations are implemented many projects will be found to be out of compliance due to past inconsistent application of standards. As projects undergo more thorough review consistent with the proposed regulations, abandonments and remedial well workovers may increase. As a result, the Division staff conservatively estimates that existing projects may have up to three wells re-abandoned or remediated and new projects may have up to 10 wells re-abandoned or remediated. The cost estimate for this requirement, based on operator estimates is $69,500 per well. At three wells per project, that totals $208,500 for existing projects. At ten wells per project, that totals $695,000 for new projects. However, because these additional costs are largely attributable to existing requirements this analysis will only attribute 25 percent of the estimated costs to implementation of the proposed regulations. Finally, proposed subdivision (a)(3) would allow the Division to approve injection operations based on an alternative demonstration that fluid will be confined to the approved injection zone notwithstanding the presence of abandoned wells that fail to meet the specifications set forth in proposed subdivision (a)(2). This allowance for an alternative demonstration may be appropriate in instances where operators can demonstrate fluid confinement despite the presence of abandoned wells that do not meet the specifications. For example, if a plugged and abandoned well has only 90 feet of cement above the specified locations, there may nevertheless be project or site-specific grounds for finding that the well will not act as a conduit. Operators, however, would carry the burden of making the demonstration, and the Division would also be required to make written findings explaining the basis for its concurrence with the demonstration. This flexibility does not impose any additional cost on operators. On the contrary, it allows operators to propose less costly alternatives to the default regulatory requirements.

Table 6. Total Statewide Costs for Evaluation of Wells within the Area of Review

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Re-Abandon P&A'd Wells within Area of Review	$79,751,250	$83,504,250	$3,753,000	$3,753,000	$3,753,000
Total	**$79,751,250**	**$83,504,250**	**$3,753,000**	**$3,753,000**	**$3,753,000**

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

Proposed section 1724.10 contains various additional requirements that apply to underground injection projects. The proposed amendments to this section would set a more uniform threshold of minimum safety, testing and operational requirements for injection projects. Improving these requirements through regulations rather than relying on case-by-case application in Project Approval Letters responds to the Division's 2015 UIC Program Assessment Report, which found that some Project Approval Letters issued in the past are incomplete, inconsistent, and lacking in clarity as to what operations were approved and under what conditions the project is required to operate.[9]

The proposed amendments to subdivisions (a), (c), and (g) are minor changes to improve clarity and consistency in the regulatory text. The changes are not substantive but are necessary to improve structure and interpretation of the regulations. These changes do not impose additional costs to operators or other businesses.

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

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[9] DOC, *SB 855 Report*, Oct. 8, 2015, on p.16. <ftp://ftp.consrv.ca.gov/pub/oil/Publications/SB%20855%20Report%2010-08-2015.pdf>

does not impose additional costs on operators because there is not charge on operators for submitting an NOI by the Division.

The proposed amendment to subdivision (d) would require that operators file an injection fluid analysis (in accordance with proposed section 1724.7.2) whenever the source of injection fluid is changed or an additional source is introduced, and as requested by the Division. Under the existing regulations, the fluid analysis is only required whenever the source of fluid is changed. The proposed amendment would make clear that the requirement also applies when an additional source is introduced to the injection stream. Without this change, the regulations are ambiguous and potentially allows the addition of new fluid sources to be unaccounted for in a fluid analysis. The Division believes it is important for both regulatory and public transparency purposes to have injection fluid analyses that accurately reflect the chemical composition of current injection fluid. Such data will improve the Division's knowledge of injection projects and facilitate better risk management decisions with respect to injection projects. The costs associated with this proposed amendment to the regulations are considered and included in the section on fluid analysis above.

a. Chemical Disclosure for Injectors near Water Supply Well

Proposed subdivision (e) would add an annual reporting requirement regarding water treatment and fluid additives for any project that includes an injection well located within one mile (by wellhead) and 500 feet (by injection/screened interval) of a water supply well. While the Division's regulation of underground injection projects is focused on ensuring injection fluid remains confined to the appropriate, approved injection zone regardless of its constituents, the proposed subdivision would serve to collect information that could be used to help verify whether or not injection fluid is contaminating water supply wells. Obtaining information about chemical additives in injection fluid would help the Division and other regulators respond in the event that contamination is reported in water supply wells (including agricultural supply wells) located near injection wells. This information would help determine whether the injection fluid is a potential source of contamination. Similar information is required of operators who seek permits (as part of their waste discharge requirements) from the Regional Water Board if they intend to reuse produced water for irrigation purposes. In addition, certain nongovernmental organizations have expressed a strong interest in greater transparency and disclosure regarding the chemicals being injected.

The requirement in subdivision (e) will apply to a relatively small subset of projects with injection wells within 500 feet of perforations for a beneficial use water well. Costs associated with these requirements will generally correspond to document retention and data submittal. All prudent injection project operators already have a water treatment process flow diagram depicting treatment processes for their injection projects. The safety data sheets are attendant to the chemicals used at the project site and would have to be retained and organized. The aggregate weight or volume of each additive would have to be tracked and compiled for transmittal to the Division. The operator would also know the intended purpose of each reportable additive and would need to document it along with the other data elements and submit the information in a digital format specified by the Division on an annual basis. The data submittal format and method is under development as part of the WellSTAR data management project. The Division estimates that these requirements would cost operators approximately $1,000 per year per applicable project due to staff time and data entry. Because few projects have water supply wells not owned by the operator in this close proximity to injectors, the Division estimates that this cost would be applied to approximately 10 percent of projects or about 77 projects per year and two additional projects every year as new projects are permitted. The total cost of this requirement is shown in Table 8.

b. Pressure Monitoring and Recording Devices

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

The requirement was added to the draft regulations after the survey was distributed to operators. In order to establish this estimate, Department of Conservation staff made inquiries to vendors, conducted internet searches, and discussed costs with engineers within the Division. As a result of this research, it is estimated that it will cost operators approximately $1,200 for each pressure monitoring and recording device and an additional $900 to install the device for all wells not already connected to a SCADA system or equipped with pressure recording devices. Based on observations in the field, Division staff estimates that most smaller operators do not have pressure monitoring and recording devices on their injections wells, while most larger operators do.

As shown in Table 7, Division staff estimates that five percent of wells owned by operators with fewer than 10 wells currently have pressure monitoring and recording devices installed and that 25 percent of operators with 10-100 injector wells already comply with this requirement. Sixty percent of operators with 100-500 wells are estimated to already have these required devices. There are 10 operators with greater than 500 UIC wells that account for over 90 percent of UIC wells. Most of these wells are cyclic steam wells and Division staff estimates that approximately 85 percent of the wells owned by these large operators are already connected to a SCADA system or have another type of pressure monitoring and recording device. As a result, the Division estimates that 6,703 wells will need to be equipped with devices costing $2,100 to procure and install. As with the other requirements above, this analysis assumes that the costs of purchasing and installing these devices will be spread across the first two years of implementation of the proposed regulations.

Table 7. Estimate of Wells that Need Pressure Monitoring and Recording Devices

Range of Injectors Owned by Operator	Count of Operators	Count of Wells	Estimated Percentage of Existing Installations	Count of Wells that Need New Device
0-10	102	241	5%	229
10-100	22	637	25%	478
100-500	9	1,973	60%	789
>500	10	34,712	85%	5,207
Total	**143**	**37,563**	**-**	**6,703**

Additionally, as mentioned above, the Division estimates that 716 new UIC wells will be added every year. To estimate which wells would be impacted by this new regulatory requirement, the new wells were assigned proportionally to operators in the same operator cohorts described above (1-10, 10-100, 100-500, and 500+ wells) and made the same estimates about what percentage of each cohort's wells would already be equipped with pressure monitoring and recording devices. As such, it is estimated that in Years 2 through 5 an additional 128 wells over what would have occurred in the absence of these regulations will be equipped with the pressure monitoring and recording devices. The costs associated with this requirement are in Table 8.

c. Requirement for Tubing and Packer

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

The amendment would also add language making clear that injection wells equipped with tubing and packer may not inject through the casing-tubing annulus unless specifically authorized to do so by the Division. When fluid is injected through the tubing only, the tubing serves as an additional barrier between the injection fluid and the underground formation penetrated by the well. When injection is allowed to occur through the casing-tubing annulus, the purpose of the tubing to serve as a secondary barrier is eliminated. This clarifying language is therefore necessary to ensure that such injection practices do not defeat the intended purpose of tubing and packer completions. Most operators of wells equipped with tubing and packer already restrict injection to the tubing, so this requirement will not impact them. However, the Division is aware of a few projects where water flood wells are designed to inject fluid into more than one location in the intended formation, so the well casing is perforated in two places, one higher in the well, and one lower in the well. As a result, in order to function as intended, injection of water needs to flow through both the tubing and casing annulus. The regulations allow the Division to evaluate these types of well designs and approve injection outside the tubing. In the case of these water flood wells, it is likely the Division will approve injection within the casing annulus, because the alternative would be the operator having to drill additional wells for the same production effect. Drilling additional wells likely poses more risk than allowing for injection through the casing annulus in these limited instances.

Finally, the proposed subdivision would amend the applicability and scope of exemptions from tubing and packer. The existing exemption for steam (cyclic steam and steamflood) wells would be retained, but the applicability of the other exemptions would be changed to reflect situations where there are no threats to USDWs rather than "freshwater." The Division is responsible for protecting USDWs, which generally includes aquifers containing less than 10,000 mg/l TDS. The term "freshwater" has historically been interpreted to include only groundwater containing 3,000 mg/l TDS or less. Accordingly, the current exemptions from tubing and packer, tied to protection of freshwater, must be revised to more accurately implement the Division's protection of USDWs. As a result, the Division estimates that approximately five percent of existing exempt wells that are not steam, air, and pipeline-quality gas injection wells may need to have tubing in packer installed. This amounts to about 17 wells that are currently not required to have tubing and packer.

Operators indicated that the cost of installing tubing and packer is approximately $39,500. As with the other requirements above, the analysis assumes that existing wells will come into compliance over the first two years of the regulations. To estimate costs for new wells in Years 2 through 5, the Division assumed that the proportion of new wells that would no longer be exempt from the tubing and packer requirement due to the "freshwater" to "USDW" change is the same as that for existing wells. This results in six new wells every year that may not otherwise have been required to have tubing and packer to need them under the proposed regulations. The total costs of this change are shown in Table 8.

d. Cyclic Steam Data Retention

Proposed subdivision (m) would require operators of cyclic steam injection wells to maintain records of the number, duration and fluid volume of all injection cycles performed on each cyclic steam injection well. Such information can vary significantly among cyclic steam wells, and may be useful to the Division for a variety of purposes, including enforcement or incident response investigations, as well as determining well or project-specific regulatory requirements. A cyclic steam well that frequently cycles between injection and production, or one that injects large fluid volumes, may require a different level of regulatory oversight than a cyclic steam well that infrequently injects a small volume of fluid. The requirement would also enable the Division to audit representations in project approval applications and other reporting regarding injection volumes. The Division's current regulations do not require operators to maintain this useful information. The proposed regulations would support Division oversight and enforcement, improve information available to the Division in incident response, and help the Division prioritize attention among the thousands of cyclic steam wells in California. Some operators who already use data analytics to evaluate project efficiency will only be subject to nominal costs to comply with this requirement. Others may need to invest in data management and record retention systems. The Division estimates, on average, record management and retention will cost approximately $3,000 per project for upfront costs for development of record retention systems and approximately $1,000 per project thereafter. There are a total of 129 projects predominantly composed of cyclic steam wells. The total direct costs are shown in Table 8.

Table 8. Total Statewide Costs for Filing, Notification, Operating, and Testing Requirements

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Chemical Disclosure	$77,000	$79,000	$81,000	$83,000	$85,000
Pressure Monitoring and Recording Device	$7,039,200	$7,308,000	$268,800	$268,800	$268,800
Tubing and Packer	$335,750	$572,750	$237,000	$237,000	$237,000
Cyclic Steam Record Retention	$387,000	$129,000	$129,000	$129,000	$129,000
Total	$7,838,950	$8,088,750	$715,800	$717,800	$719,800

7. Mechanical Integrity Testing Part One – Casing Integrity

The Division's existing regulations require a "two-part demonstration" of mechanical integrity. The first part consists of a pressure test of the casing-tubing annulus, while the second part consists of a test to demonstrate the absence of fluid migration behind the casing, tubing, or packer. The amendment to the Division's regulations would expand the mechanical integrity testing regime by addressing in greater detail the two parts to the demonstration in separate sections. The purpose of these new sections is to make the testing regime more reliable and predictive in nature, and therefore improve the likelihood of identifying potential well integrity issues before leaks occur.

Proposed section 1724.10.1 would provide the requirements for demonstrating casing integrity. Proposed subdivision (a) would require periodic casing pressure tests performed at the maximum allowable surface pressure or 200 psi, whichever is greater. One initial point of departure from the Division's current regulations is the amended requirement that would abandon reference to pressure testing the "casing-tubing annulus" and replace it with "pressure test of the casing." The current language assumes the presence of tubing and packer even though the regulations allow certain injection wells, like cyclic steam, to be completed without tubing and packer. This has resulted in confusion and inconsistent application of the testing requirement for wells without tubing and packer. The Division does not consider it appropriate to excuse tubingless wells from the pressure test requirement.

The proposed subdivision would specify the parameters for conducting the test and for determining whether a well passes the test. Testing at the maximum allowable surface pressure is necessary to confirm the well can hold the maximum pressure at which it is allowed to operate. The regulations would also specify what would indicate a passing test. These parameters are based on industry standards and practices, and the Division's experience and expertise in supervising the pressure testing of wells.

The casing pressure test would be required at least once every five years, prior to recommencing injection operations following the repositioning or replacement of downhole equipment, or whenever requested by the Division. These are the same frequency requirements as under the Division's current regulations, however this now applies to many wells that are not currently consistently covered. Wells that are not consistently pressure tested under the current regulations due to the ambiguity in the language include all cyclic steam wells, approximately 86 percent of steam flood wells, and an estimated 337 wells that are currently exempted from the tubing and packer requirement on other bases. The Division estimates that wells meeting these criteria encompass 30,394 wells.

The Division's cost estimate for conducting a pressure test is $10,871 per well. Operators' responses estimating the cost of this requirement varied substantially, ranging from as low as $300 to tens of thousands of dollars. On average, excluding the same outlier who made flippant remarks, the cost came out to be $10,871 to conduct the pressure test. For purposes of this analysis, the Division assumed that 20 percent of all wells would be tested each of the first five years. In reality, the number would vary in an unpredictable way but this method accounts for all of the wells being tested within the time period covered by this analysis.

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

Table 9. Total Statewide Costs for Mechanical Integrity Testing, Part One

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Pressure Testing	$66,082,635	$66,082,635	$66,082,635	$66,082,635	$66,082,635
Total	**$66,082,635**	**$66,082,635**	**$66,082,635**	**$66,082,635**	**$66,082,635**

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

Proposed section 1724.10.2 would expand upon the existing testing requirement to demonstrate the absence of fluid migration behind the casing, tubing or packer. The existing requirement for this "part two" mechanical integrity testing is found in section 1724.10, subdivision (j)(2). The current regulation is vague. Among its deficiencies, the regulations do not provide any further guidance or direction regarding the procedures for operators to use in making the required demonstration. Proposed subdivision (a) would remedy this by specifying that operators can satisfy the requirement by performing the procedures specified in proposed subdivisions (d) through (f) – namely, a radioactive tracer survey, noise log, or temperature survey. Additionally, the proposed regulations would allow flexibility for the Division to accept an alternative method. Operators would have several options to satisfy the requirement (including case-by-case methods not set forth in the regulations), however, operators would need to obtain written approval from the Division prior to performing an alternative mechanical integrity demonstration.

Proposed subdivision (b) identifies when “part two” testing is required. Essentially, the frequencies prescribed under the existing regulations would be retained. The current frequencies are based on the relative risk of the type of injection well. For example, disposal injection wells are subject to more frequent testing than steam flood wells equipped with tubing and packer because disposal wells generally inject greater volumes of lower quality fluid. The Division believes retaining the risk-based frequencies of the existing regulations is the most appropriate approach.

The existing regulations are silent, however, with regard to the testing frequency for cyclic steam injection wells. This has led to instances of such injection wells going untested. The Division finds no science or risk-based reason to excuse cyclic steam wells from “part two” mechanical integrity testing. Indeed, cyclic steam wells, which periodically inject hot, highly pressurized steam, are repeatedly subject to considerable variations in temperature and pressure. These factors subject the well to stress, which makes the wells vulnerable to integrity failure. Accordingly, the proposed regulations would require most cyclic steam wells not equipped with tubing and packer to be tested at least once every two years. Cyclic steam wells equipped with tubing and packer would need to be tested at least once every three years because the use of tubing and packer provides an additional layer of protection against fluid migration from a well with compromised casing integrity.

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

The testing methods and frequencies set forth in the proposed regulations are intended to be the default requirements that would apply for the majority of injection projects, but the Division finds it necessary to allow regulatory flexibility for deviation from the default on a case-by-case basis. This flexibility is necessary because California’s geology, oilfield practices, and natural resource landscapes, are notoriously diverse. Additionally, the wells in operation also differ significantly in age and condition. In feedback to the Division’s “Discussion Draft,” operators repeatedly urged against a “one size fits all” regulatory approach. Proposed subdivision (c) would allow the Division to approve testing methods and frequencies that differ from the defaults set forth in the proposed section, provided the variance, and its basis, is documented in writing. This provision will avoid an unduly rigid testing requirement and enable the Division to tailor requirements to specific circumstances where appropriate.

Proposed subdivisions (d), (e), and (f) would specify the default parameters for an acceptable radioactive tracer survey, temperature survey, and noise log, respectively. These parameters are based on industry standards and practices, and the Division's experience and expertise in supervising such testing procedures.

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

The cost estimates for MIT Part Two as required in 1724.10.2 are shown in Table 10. To estimate the costs of MIT 2, the Department surveyed operators about both the costs of radioactive tracer surveys and temperature logs and also asked which of the two they would be likely to use – 82 percent of respondents indicated that they would likely use a tracer survey and 18 percent said they would use temperature logs. The cost estimates provided by operators were combined and averaged. This effectively weighted the costs based on what test the operators anticipated using. The resulting cost estimate is $5,579 per well. There are 25,346 existing cyclic steam wells and an additional 483 new cyclic steam wells in Years 2 through 5 that would need to be tested every two years. Additionally, 4,711 existing and 90 new steam flood wells would need to be tested every two years. Fourteen percent or approximately 748 of existing steam flood wells that would need to be tested every five years, which is consistent with current regulatory requirements. The calculations in the table assume that for those wells requiring testing every two years, half of all wells would be tested each year. For the steam flood wells without tubing and packer which would be required to be tested every two years, rather than every five years as previously required, the cost of testing one-fifth of the wells every year was subtracted from the new cost of having to test one half of all wells every year under the new requirement. The results are in the Table 10.

Mechanical integrity testing, as required under proposed sections 1724.10.1 and 1724.10.2, is necessary to ensure fluid is confined to the approved injection zone and does not escape through leaks in the well casing. While no single type of mechanical integrity test provides complete information about the condition of a well, the combination of required tests will provide the Division and the operator multiple sets of data about the well, which will improve detection of current and potential well integrity concerns.

Table 10. Total Statewide Costs for Mechanical Integrity Testing, Part Two

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Waste Disposal wells (every year)	No change in costs.				
Cyclic Steam Wells	$70,702,667	$76,823,726	$76,823,726	$76,823,726	$76,823,726
Steam flood wells (without tubing and packer)	$7,884,801	$8,035,434	$8,035,434	$8,035,434	$8,035,434
Steam flood wells with tubing and packer	No change in costs.				
Gas Disposal	No change in costs.				
Water Flood	No change in costs.				
Pressure Maintenance	No change in costs.				
Total	**$78,587,468**	**$84,859,160**	**$84,859,160**	**$84,859,160**	**$84,859,160**

9. Maximum Allowable Surface Pressure

Proposed section 1724.10.3 would require operators to estimate the maximum allowable surface pressure (MASP) using the specifications provided in subdivision (a), or by demonstrating to the Division that an alternate and higher MASP step rate test does not fracture or cause more fractures in the existing approved injection zone and is necessary for effective resource production. The costs associated with this new section are covered in the project data requirements section above because the results of the tests are needed to fulfill project data requirements in proposed section 1724.7, subdivision (a)(4).

10. Surface Expression Prevention and Response

Proposed section 1724.11, subdivision (a), would codify in regulation the Division's existing policy and practice that underground injection operations not result in surface expressions. The term "surface expression" would be defined in the regulations as a flow, movement, or release from the surface to the surface of fluid or other material such as oil, water, steam, gas, formation solids, formation debris, material, or any combination thereof, and that appears to be caused by injection operations. Surface expressions can be hazardous to humans and wildlife. In 2011, an oilfield worker died when he fell into a surface expression. The proposal to codify this policy in regulation is intended to promote transparency, increase safety measures, and strengthen the Division's authority to prevent damage to life, health, property and natural resources.

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

These requirements are consistent with existing requirements already in place in conditions of approval for existing projects in cyclic steam projects in shallow diatomite. All projects that the Division believes pose a risk of surface expressions have already made the investments necessary to meet these requirements. Operators in shallow diatomite fields contract with third parties to monitor the surveillance equipment and provide interpretative reports to the operators. Technology to monitor surface expressions include tilt meters, Interferometric Synthetic Aperture Radar (InSAR) technology, or laser measurement systems to measure deformation and risk of surface expressions in their field operations.

Consistent with existing project approval conditions and current practice, if a threat of surface expression is detected, the proposed regulations would require the operator to cease injecting into nearby injection wells in order to mitigate the threat. Injection would be prohibited until the Division provides written approval to resume. The requirements of proposed subdivision (b) are necessary to facilitate early detection of surface expressions or anomalies that could cause surface expressions. As mentioned above, without a standardized set of monitoring requirements, the Division has imposed requirements in individual project approval letters – an approach the Division considers inferior to regulation in this instance. The proposed regulations will help promote consistent application practices.

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

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

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

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

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

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

Proposed subdivision (j) would require operators to measure and report on the volumes of oil removed from surface expressions. These volumes can be significant, and can be produced and sold as a commodity. While current regulations do not require operators to report such volumes, the Division does require operators to report production from seeps if they occur.

As indicated above, all projects identified by the Division to pose a risk of surface expressions have already made the investments to meet project approval requirements that are substantially similar to the requirements in this section. As such, existing projects will not incur additional costs associated with these requirements. However, an earlier “discussion draft” version of the regulations was written such that they were construed by operators to apply to additional projects over what is currently required. An operator with significant cyclic steam operations in diatomite provided the Department with an estimate of $300,000 per project and $100,000 per project per year for monitoring. To estimate the cost of applying these requirements the Division estimates that over the next five years, two projects may require surface expression monitoring equipment and monitoring. For the sake of estimating the cost impact, this analysis assumes these hypothetical projects will be added in Year 2 and Year 4 of the five years being analyzed. The cost estimates are in displayed in Table 11.

Table 11. Total Statewide Costs for Surface Expression Prevention Costs

Requirements	Year 1	Year 2	Year 3	Year 4	Year 5
Surface Expression Prevention	$0	$420,000	$120,000	$540,000	$240,000
Total	**$0**	**$420,000**	**$120,000**	**$540,000**	**$240,000**

11. Surface Expression Containment

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

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

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

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

This analysis does not attribute any additional costs associated with this section. All of the proposed requirements in this section are consistent with current practice in response to surface expressions. These regulations are intended to codify best practices following a surface expression event. To the extent that an operation does not cause unauthorized releases of fluid to the surface, this section will not impose any additional costs on operators.

12. Universal Operating Restrictions and Incident Response

Under current regulations sections 1724.10, subdivision (h), and 1748.3, subdivision (g), underground injection control operators must cease injection upon written notice by the Supervisor. The proposed section 1724.13, subdivision (a), would specify a list of circumstances that require operators to notify the Division and cease injection until the Division authorizes resumption. Some of the circumstances, such as a failed mechanical integrity test and indication of fluid migration outside of the approved injection zone, relate directly to the Division's mandate to protect life, health, property and natural resources. Other circumstances, such as failure to perform a mechanical integrity test within the required timeframe and failure to submit injection and production reports, are intended to impose stronger consequences for non-compliance with testing and reporting requirements. With respect to all circumstances listed in the proposed section, the Division finds that operators should be required to cease injection on their own initiative rather than wait for the Division to follow-up with such directions. For all intents and purposes this occurs under the existing regulatory framework, however the Division must react and provide written notice to operators that they must halt injection. Prudent operators already halt injection when the listed, dangerous or risky events occur.

In some instances, under existing regulations, some operators who violate those requirements may continue operations while leaving it to the Division to follow-up with a remedial order. The proposed section is necessary to create immediate, consequential obligations for operators to cease injection if the well is not in compliance with the specified requirements. Operators who continue to inject in violation of the proposed section would be separately liable for violating the proposed section, in addition to the underlying violation (if applicable) that triggered the obligation to cease injection.

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

Because this creates an automatic mechanism under which operations must halt injection in specified circumstances without written notice by the Division, the proposed regulations may result in a small increase in the number of violations if an operator continues injecting under unsafe circumstances in violation of their project approval requirements. It is standard practice for operators to cease injection when problems arise, so the effect of this change would be to take the onus off of the Division to contact the operator and tell them to stop and instead, requires the operator to cease injection without written notice by the Division. This section does not pose any significant additional cost on operators.

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

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

Proposed section 1724.14, subdivision (a), would require the operator to monitor on a daily basis the California Integrated Seismic Network (CISN) for earthquakes of magnitude 2.7 or greater with a hypocenter occurring within a spherical radius of one mile of the injection interval of any active disposal injection well. The proposed section accomplishes the need to monitor seismic activity near disposal injection wells at low cost to the industry. Operators can monitor in real time relevant seismic activity through CISN's free website.

The requirement would apply only to disposal wells because disposal wells generally inject greater volumes at greater depths than other types of injection wells, and therefore are more likely to be associated with seismic activity than any other form of injection well subject to Division regulation. Additionally, the reporting trigger would be limited to downhole injection intervals within a one-mile spherical radius of the hypocenter, which is the underground center-point of the seismic activity. The distance between the injection interval and the hypocenter is a more appropriate trigger than the distance between the injection internal or wellhead and the epicenter (the point on the earth's surface directly above the seismic activity), as the latter would result in reporting events that are much less likely to be connected with injection, particularly where the hypocenter is miles below wells injecting into geologically separate formations at only hundreds of feet below the surface. Limiting the requirement to disposal wells within a certain distance from the hypocenter is necessary to appropriately tailor the regulatory burdens to the applicable activities and issues of most concern.

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

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

This proposed section would impose minor, if any, additional costs on operators as they could sign up for the United States Geological Survey's Earthquake Notification Service (ENS) and evaluate whether or not earthquakes they are alerted to are within one mile of their injection operation or they could monitor the CISN website once a day to see if an earthquake had occurred nearby. In the event the hypocenter was within one mile of an operator's disposal well, they could email or call the Division. The Division, in consultation with the California Geological Survey, would be responsible for any subsequent study pertaining to a possible relationship between the seismic event and the injection operation.

Total Direct Costs

The total direct costs of the proposed regulations are shown in Table 12. As mentioned above, the Department anticipates that operators will come into compliance with the new regulations over the first two years that the regulations are in effect. In the first year of compliance, the proposed regulation could cost the UIC operators over $221 million statewide. In Year 2 of compliance, the cost of the proposed regulation could rise to over $235 million because the estimated costs are applied to both existing wells and projects and new wells and projects.

Table 12. Total Statewide Costs of Proposed Regulations

Direct Cost Category	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	$2,184,458	$2,320,208	$135,751	$135,751	$135,751
Map of underground disposal horizons, mining, and other subsurface industrial activities	$941,333	$1,015,169	$73,836	$73,836	$73,836
Compendium of Information on Wells in Area of Review	$2,092,658	$4,352,715	$167,400	$167,400	$167,400
Casing Diagrams	$3,803,254	$4,340,254	$537,000	$537,000	$537,000
Reservoir Characteristics	$1,614,533	$1,872,833	$258,300	$258,300	$258,300
Reservoir Fluid Data	$1,850,535	$2,029,041	$178,506	$178,506	$178,506
Structural Contour Map	$2,651,873	$2,908,049	$256,176	$256,176	$256,176
Geologic Cross Sections	$2,673,511	$2,845,756	$172,245	$172,245	$172,245
Electric Log	$1,525,410	$1,668,942	$143,532	$143,532	$143,532
Fluid Analysis	$934,870	$1,006,618	$697,550	$697,550	$697,550
Step-Rate Tests	$14,917,266	$16,392,600	$1,475,334	$1,475,334	$1,475,334
Electronic Data Submittal/Data Formatting	$13,413,893	$13,413,893	$0	$0	$0
Chemical Disclosure	$77,000	$79,000	$81,000	$83,000	$85,000
Re-Abandon P&A'd Wells within Area of Review	$19,937,813	$20,876,063	$938,250	$938,250	$938,250
Pressure Monitoring & Recording Device	$7,039,200	$7,308,000	$268,800	$268,800	$268,800
Tubing and Packer	$335,750	$572,750	$237,000	$237,000	$237,000
Cyclic Steam Record Retention	$387,000	$129,000	$129,000	$129,000	$129,000
Pressure Testing - MIT 1	$66,082,635	$66,082,635	$66,082,635	$66,082,635	$66,082,635
Cyclic Steam Wells-MIT 2	$70,702,667	$76,823,726	$76,823,726	$76,823,726	$76,823,726
Steam flood wells (without tubing and packer)-MIT 2	$7,884,801	$8,035,434	$8,035,434	$8,035,434	$8,035,434
Surface Expression Prevention	$0	$420,000	$120,000	$540,000	$240,000
Total	**$221,050,456**	**$234,492,683**	**$156,811,474**	**$157,233,474**	**$156,935,474**

Direct Cost Impact on Typical Businesses

For the purposes of this economic assessment, the Division has determined that a typical business represents an estimated nine percent of all statewide operators with injection wells. Twelve operators own 94 percent of the injection well inventory and generated more than $100 million each from both oil and gas production in 2017. In total, these 12 operators generated nearly $7.9 billion in 2017, or nearly 88 percent of the $8.9 billion gross revenue among all injection well owners. The Division considers these twelve operators as a "typical" business.

Table 13. Direct Cost Impact on "Typical" Business

Year	Total Direct Cost	Expected Share of Costs (%)*	Expected Share of Costs ($)	Estimated Total Revenue	Compliance Burden
1	$221,050,456	94%	$207,787,428	$7,867,882,003	2.6%
2	$234,492,683	94%	$220,423,122	$7,867,882,003	2.8%
3	$156,811,474	94%	$147,402,785	$7,867,882,003	1.9%
4	$157,233,474	94%	$147,799,465	$7,867,882,003	1.9%
5	$156,935,474	94%	$147,519,345	$7,867,882,003	1.9%

Data Source: DOGGR "2017 Production Access Database.zip" (2/6/2018); DOGGR "2017 UIC Wells Inventory" (November 25, 2017).
* Based on percentage of class II injection wells owned.

Because twelve operators own 94 percent of the State's injection wells, the Division expects them to take on roughly 94 percent of the State's compliance cost burden (see "Expected Share of Costs" in Table 13).[10] The expected share of costs divided by their estimated total revenue represents their compliance burden. On average, the direct costs make up 1.9 to 2.8 percent of the gross revenue for the typical operator.

The costs of compliance to a typical operator will likely reduce its profit margins and impact investment decisions in the short-term. The funds necessary to comply with the proposed regulations would likely be diverted from some other form of spending, such as dividends to shareholders, direct production activities or research and development, which, to some extent, restrict an operator's ability to fully utilize its funds according to its own priorities. In the short-term, the costs of compliance could divert time and resources away from production. And depending on how funds are diverted to meet the regulatory burden in the long-term, fewer resources for research and development, for example, could also affect innovation and exploration. While the costs associated with this regulation would represent a small portion of overall expenditures for typical operators, a reduction in profits due to regulations could conceivably have some effect on stock prices, which would make raising capital more challenging, reduce dividend payments, and reduce overall capital gains to current shareholders.

[10] Total direct costs are a mix of both per project and per well costs. Because the UIC wells are overwhelmingly owned by a handful of operators, the Division did not see a need to extrapolate compliance cost burden by both project costs and by well costs.

In addition to these proposed regulations, the Division has other pending rulemakings that could become effective around the same time as this rulemaking, including one that would affect oil and gas producers with pipelines in sensitive areas and another that would affect operators with idle wells. Although the economic impact analyses intentionally overestimate the direct costs for each of the proposed regulations in order to create a conservative cost estimate, the cumulative costs of the regulations could pose a financial burden on operators that are affected by more than one of the proposed regulations. Most of the operators that are affected by more than one proposed regulation are large operators that should be able to absorb these costs. However, their profit margins will shrink in the short-term. Statewide oil and gas production could experience some reduction in production activity in the short-term.

However, the typical operator's business practices have evolved to withstand the extreme volatility of crude oil and natural gas prices. In 2016, the US EIA commissioned IHS Global Inc. (IHS) to perform a study of upstream drilling and production costs associated with drilling, completing, and operating wells and facilities. Even in extended periods of a low commodity price environment, the study identified multiple ways in which operators were able to cut costs by a number of methods, including the cutting of operating costs, the prioritization of projects, the implementation of technological improvements and innovations, and the adoption of best practices and improvements related to well design.[11] As a result, the Division expects the direct costs to create a large, but absorbable burden on these typical operators.

[11] US Energy Information Administration, Trends in US Oil and Natural Gas Upstream Costs, March 23, 2016. <https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf>

Direct Cost Impact on Small Businesses

For the purposes of this economic assessment, the Division has determined that small businesses represent an estimated 70 percent of all statewide operators with injection wells. Small businesses are the 94 operators that generated less than $10 million each from both oil and gas production and only own 1.2 percent of the injection well inventory. In total, these 94 operators generated roughly $90 million in 2017, or only 1.02 percent of the $8.9 billion gross revenue among all injection well owners. The Division considers these 94 operators as small businesses.

Table 14. Direct Cost Impact on "Small" Businesses

Year	Total Direct Costs	Expected Share of Costs (%)*	Expected Share of Costs ($)	Estimated Total Revenue	Compliance Burden
1	$221,050,456	1.2%	$2,652,605	$90,494,280	2.9%
2	$234,492,683	1.2%	$2,813,912	$90,494,280	3.1%
3	$156,811,474	1.2%	$1,881,738	$90,494,280	2.1%
4	$157,233,474	1.2%	$1,886,802	$90,494,280	2.1%
5	$156,935,474	1.2%	$1,883,226	$90,494,280	2.1%

Data Source: DOGGR “2017 Production Access Database.zip” (2/6/2018); DOGGR “2017 UIC Wells Inventory” (November 25, 2017).

* Based on percentage of class II injection wells owned.

Because these 94 operators own 1.2 percent of the State’s injection wells, the Division expects these operators to take on roughly 1.2 percent of the State’s compliance cost burden (see “Expected Share of Costs” in Table 14).[12] The expected share of costs divided by their estimated total revenue represents their compliance burden. On average, the direct costs make up 2.1 to 3.1 percent of the gross revenue for a small operator.

As discussed in the section regarding direct cost impacts on typical operators, the costs of compliance to a small operator will likely reduce its profit margins and negatively impact investment decisions in the short-term. The funds necessary to comply with the proposed regulations would likely be diverted from direct production activities in this case, which could restrict an operator’s ability to produce to its full productive capacity. Within the range of small operators, the higher producing operators should be able to absorb the compliance costs. However, approximately two-thirds of the small operators generate even less production and less revenue than the average small operator. The smallest operators will likely face financial difficulties in meeting the costs of compliance and could exit the industry, leaving the state with some reduction in statewide oil and gas production in the short-term. In the long-term, small operators may learn to adapt, large companies may buy projects and wells from small operators, and/or operators will become more efficient and productive to make up for any short-term production losses.

[12] Total direct costs are a mix of both per project and per well costs. Because the UIC wells are overwhelmingly owned by a handful of operators, the Division did not see a need to extrapolate compliance cost burden by both project costs and by well costs.

Direct Cost Impact on Individuals

Crude Oil

The direct costs of the proposed regulations are not expected to result in a cost impact to individuals or final consumers of petroleum products. Although end products from the refinement of crude oil, such as diesel and gasoline, incorporate the cost of the crude oil purchased by refineries, the price of the crude oil itself is not determined by individual operators in California. Because crude oil is the world's most traded commodity, its price is primarily established by speculators and hedgers in the futures market who try to secure a price now in anticipation of or protection from price changes in the future.

The price of California crude oil is typically benchmarked against a grade of a light crude oil called West Texas Intermediate (WTI). The price can be higher or lower based on both its relative quality compared to the WTI and the cost of transportation to refineries. In general, the transportation cost is borne by the operator and not the refinery that purchased the crude oil.[13] This is due to pressure from the global market. California refineries imported approximately 70 percent of their crude oil from Alaska and foreign sources in 2017; a trend toward imports that has been increasing steadily since 1999.[14] Refineries could simply find an out-of-state alternative to domestic producers if domestic producers increased their prices or reduced their production. As a result, oil producers cannot pass the costs of compliance on to refineries or end users.

Natural Gas

The direct costs of the proposed regulations are not expected to result in a cost impact to individuals or final consumers of natural gas. Global natural gas markets are becoming increasingly interconnected, creating a greater flexibility to respond to changes in supply and demand.[15] The US shale boom has driven much of this globalization by providing a glut of gas for export. This shale gas is sourced from multiple locations throughout the continental US, providing for flexibility of product delivery with little to no price impact when a region or pipeline is disrupted.[16]

Nationally, California accounts for only one percent of total natural gas reserves and production; in-state output equals about one-tenth of state demand and is used exclusively in-state.[17] Thus, California production does not enter the global market and a loss in production would not affect global market prices. This has been demonstrated during recent supply disruptions, such as Hurricane Harvey in 2017, when prices remained stable in spite of a 26 percent peak loss in offshore gas production.[18]

[13] American Petroleum Institute (API), *Understanding Crude Oil and Product Markets*, last accessed March 22, 2018. <http://www.api.org/~/media/Files/Oil-and-Natural-Gas/Crude-Oil-Product-Markets/Crude-Oil-Primer/Understanding-Crude-Oil-and-Product-Markets-Primer-High.pdf>

[14] California Energy Commission, *Oil Supply Sources to California Refineries*, last accessed March 15, 2018. <http://www.energy.ca.gov/almanac/petroleum_data/statistics/crude_oil_receipts.html>

[15] International Energy Agency, *Global Gas Security Review: How is LNG Market Flexibility Evolving?* 2017, pg.3. <https://www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf>

[16] Id. at 33.

[17] US Energy Information Administration, *California State Profile and Energy Estimate; Profile Analysis*, last updated October 19, 2017. <https://www.eia.gov/state/analysis.php?sid=CA>

[18] International Energy Agency at 33.

With more than eight interstate pipelines connecting California to natural gas basins in the Southwest, Canada, and the Rocky Mountains[19], California is able to access the greater US market for natural gas and can simply increase its import volume to cover any production loss caused by these regulations. Thus, the global price will not be affected by these regulations, and the local price should remain consistent with the global price.

Current and Prospective Shareholders

Although operators that produce crude oil and natural gas cannot pass costs onto refineries and individuals, a reduction in profits could negatively affect share prices of a publicly traded oil and gas companies with underground injection wells in California. If profitability of such a company is affected by the proposed regulations in any meaningful way, both current and prospective shareholders might not find the stock offerings to be attractive. In the end, both corporations and individuals could be affected by the regulatory environment if stock prices are negatively affected – capital gains to shareholders would be reduced, raising capital would become more challenging, and any dividend payments would be reduced. However, it should be noted that the compliance costs imposed by these regulations are a small fraction of typical fluctuations in oil and gas prices in any given year. As such, they are not likely to be considered a significant variable for stock performance relative to other market forces such as oil price, assets, known reserves, etc.

[19] California Public Utilities Commission, *Natural Gas and California*, Last accessed March 15, 2018. <http://www.cpuc.ca.gov/natural_gas/>

Economic Impacts

The Division can estimate the economic impact of every dollar spent from the costs of compliance by using an input-output (I-O) model to capture the secondary indirect effects of direct spending. Although there are a wide range of commercially available I-O models, this analysis uses the Regional Input-Output Modeling System (RIMS II) to estimate the regional economic impact.

RIMS II

Following calculation of the direct costs, indirect costs and economic impacts were estimated using a computational general equilibrium model of the California economy provided by the BEA and known as the Regional Input-Output Modeling System II (RIMS II, 2007/2015).[20] The RIMS II model generates year-by-year estimates of the total regional effects of a policy or set of policies. The model is designed to be regionally specific and produces a set of multipliers representing output that occurs in affected industries delivered to final demand. RIMS II Type I multipliers were used in the analysis and assessment.[21] In this analysis, because direct spending is necessary to satisfy regulatory requirements, spending is treated as an investment purchase rather than an intermediate input.

Identified industries that would be affected by the proposed UIC regulations with their corresponding RIMS II Industry Code are shown in Table 15.

[20] The Bureau of Economic Analysis does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

[21] Multipliers that account for only the interindustry effects (direct and indirect) of a final-demand change. BEA RIMS II Guidelines, p. G-3.

Table 15. RIMS II Industry Code

Direct Cost Category	RIMS II Industry Code	Industry Description	Related NAICS Code
Map of Area of Review	541300	Architectural, engineering, and related services.	541380
Map of underground disposal horizons, mining, and other subsurface industrial activities	541300	Architectural, engineering, and related services.	541360
Compendium of Information on wells in AOR	541330	Architectural, engineering, and related services.	541330
Casing Diagrams	541330	Architectural, engineering, and related services.	541330
Reservoir Characteristics	541330	Architectural, engineering, and related services.	541330
Reservoir Fluid Data	21311A	Support activities for oil and gas extraction	213112
Structural Contour Map	541300	Architectural, engineering, and related services.	541380
Geologic Cross Section	541300	Architectural, engineering, and related services.	541380
Electric Log	21311A	Support activities for oil and gas extraction	213112
Fluid Analysis	541300	Architectural, engineering, and related services.	541380
Step-Rate Tests	21311A	Support activities for oil and gas extraction	213112
Electronic data submittal/data formatting	518200	Data processing, hosting, and reltated services	518210
Chemical Disclosure	21311A	Support activities for oil and gas extraction	213112
Pressure Monitoring & Recording Device	333130	Mining and oil and gas field machinery manufacturing	33313
Re-abandon P&A Wells within AOR	21311A	Support activities for oil and gas extraction	213112
Tubing and Packer	333130	Mining and oil and gas field machinery manufacturing	33313
Cyclic Steam Record Retention	518200	Data processing, hosting, and reltated services	518210
Pressure Testing - MIT 1	21311A	Support activities for oil and gas extraction	213112
Cyclic Steam Wells-MIT 2	21311A	Support activities for oil and gas extraction	213112
Steam flood wells (without tubing and packer)-MIT 2	21311A	Support activities for oil and gas extraction	213112
Surface Expression Prevention	333130	Mining and oil and gas field machinery manufacturing	33313

Data Source: BEA, *California RIMS II data (Type I)*. 2007/2015.

Assumptions and Limitations

The resultant economic impacts from the RIMS II analysis have several important assumptions that could limit or reduce the state economic impact. First, it assumes businesses in the affected industries have no supply constraints and can satisfy additional demand with an increase in inputs and labor from within the state. Second, it assumes businesses have fixed patterns of purchases, or increase in output requires the same proportionate increase in input. Third, the model assumes businesses use local inputs if they are available.

Regarding the first and third assumptions, one particular concern by operators in the oil and gas industry is the availability of rigs to address all of the testing required by not just the proposed UIC regulations, but also testing for active production wells and idle wells. The Division believes that service contractors in or near California may not yet be operating at full capacity. In other words, enough well service rigs are likely available in-state or regionally to meet demand. According to a monthly survey of well service rigs by the Association of Energy Service Companies (AESC), the utilization rate of well service rigs for the geographic region that includes California, "West Coast/Alaska," was approximately 41 percent in February 2018.[22] Furthermore, none of the three closest regions – the Rocky Mountain area, the West Texas/Permian basin, and the Mid-Continent – show utilization rates for well service rigs greater than 51 percent.[23] If the required testing can be handled by the state's inventory of workover rigs, then there would not be a reduction in the estimated economic impacts from use of out-of-state rigs. Because they are known for their mobility, well service rigs can likely be brought in from outside of the state if demand cannot be met in-state. However, if additional workover rigs are brought in from outside of the state, then the estimated economic effects in the model would not be fully realized.

Regarding the second assumption, the reality is that businesses – particularly in the oil and gas industry – become more efficient over time with changes in processes and technology that allow them to do more with less. This applies not only to the service contractors, but also to the operators who may find more cost-effective solutions to satisfy the requirements of the proposed regulations. Therefore, the results of the assessment represent the impact's upper bound.

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[22] Association of Energy Service Companies, *AESC Rig Count – Past Months Excel (Download)*, last accessed 4/10/2018. <http://www.aesc.net/AESC/Industry_Resources/Rig_Counts/AESC/Industry_Resources/Well_Service_Rig_Count.aspx?hkey=0f7d9987-7819-421e-9c4c-7e7d9323ab3c>

[23] Ibid.

Results of the Assessment

The resultant indirect economic impacts are shown in Table 16 for gross output, earnings, jobs, and value added. The breakdown of economic impacts by category of regulatory spending can be found in detail in Appendix C through F.

Table 16. Annual Indirect Economic Impacts from Regulatory Spending

Economic Impact	Year 1	Year 2	Year 3	Year 4	Year 5
Gross Output	$301,558,461	$400,243,859	$211,865,175	$212,496,059	$212,049,967
Earnings	$90,436,866	$93,670,873	$62,095,594	$61,959,207	$61,680,684
Jobs	1,343	1,433	906	908	906
Value Added (GSP)	$188,807,492	$200,138,941	$135,426,360	$135,683,030	$135,502,659

Data Source: Computed from BEA, *California RIMS II data (Type I)*. 2007/2015.

Because the costs of compliance are expected to be largest in the first two years of the proposed regulations' effective date, the indirect economic impact is largest in the first two years. As discussed in the Direct Cost Impact sections, despite the large positive economic impact derived from regulatory spending, the operators themselves are likely to experience negative impacts that are not captured in this input-output model, including lower profit margins, reduced production levels, diverted investments, and lower share prices, among other possibilities. The costs of compliance will ultimately mute the largely positive indirect economic impacts from the required regulatory spending.

Creation or Elimination of Jobs within California

The proposed regulations are expected to create additional jobs in employment sectors such as construction, engineering, testing, monitoring with specialized equipment needs, and manufacturing of essential products required for implementation. As shown in Table 16, the expected job growth from the final demand change ranges from 906 to 1,433 in the first five years of the analysis. Equipment operators for oil rigs and other specialized skilled workers will be in higher demand to conduct the required testing. Thus, the industrial sector most affected by the direct spending from regulation would be service contractors within the oil and gas industry. As mandated work associated with remediation and drilling of new wells has been completed, the additional jobs will likely decrease over time. However, additional employment as outlined in the requirements for continuous maintenance and testing sectors will likely remain permanent. The table in Appendix E shows a detailed analysis of jobs created resulting from the expenditures mandated by the regulations.

Employment will certainly consist of full- and part-time jobs, though the RIMS II data does not capture the difference. The calculated output per worker (earnings divided by jobs) is about $65,000 to $69,000 per year over the five years of the analysis.

While the I-O model captures job growth in companies that perform support activities on a contract or fee basis for oil and gas operations, there is a possibility that operators themselves may downsize the number of in-house employees or, in the case of small operators, exit the industry altogether. Both examples would lead to job losses not captured by the RIMS II model.

Creation of New Businesses or the Elimination of Existing Businesses within California

The initial increase in spending on testing, corrected plugging and abandonment, data submissions, and other regulatory activities is expected to lead to gross output of anywhere from $212-$400 million per year over the five years of the analysis (see Table 16). Oil and gas service contracting businesses likely will see an increase in demand for their services as a result of the proposed regulations. The gross output will not only affect the industries that provide the contracted services, but also all of the related industries that supply inputs to the contractors. Therefore, oil and gas service contractors and their various suppliers will likely see an increase in demand for their services as a result of the proposed regulations. However, barriers to entry, such as the cost of equipment needed to perform testing or plugging and abandonment work, could limit the number of new service contractor businesses. The technology-intensive, specialized, niche market for testing services, well remediation, and monitoring likely creates barriers to entry that outweigh any incentives to entry created by additional demand attributed to the proposed regulations. The expenditures will likely be absorbed by the directly regulated companies.

Regarding oil and gas operators themselves, the costs of compliance could be a heavy financial burden on smaller businesses. These smaller operators could exit the industry leading to fewer operators in the state.

Competitive Advantages or Disadvantages for Businesses Currently Doing Business within California

Because they do not have control over the sale price of the extracted hydrocarbon, the regulated operators in California will experience reduced profit margins in the short-term, creating a competitive disadvantage. Small operators are particularly vulnerable to the costs associated with the regulations, possibly contributing to possible drop in statewide hydrocarbon production. However, in the long-term, operators in California reduce risk and increase efficiency, revenue, and profit by constantly improving both their technological capabilities and their processes. The Division does not expect the proposed regulation to interfere with an operator’s investment in efficiency, particularly for a mid- to large-sized operator that has the resources to invest in research and development and/or outsource work to service contractors. Since most of the state’s inventory of injection wells is owned by the largest operators in the state, the Division does not anticipate a competitive disadvantage resulting from proposed regulations in the long-term for California’s oil and gas producers as a whole.

Most of the indirect economic benefits will be realized by service contractors in the oil and gas industry. The proposed regulations are likely to negatively affect statewide operators’ competitive advantage in the short-term as profits will likely be affected by the costs of compliance. In the long-term, however, the Division expects the operators to make up for the reduced profit margin by developing and adopting technological and process efficiencies to meet the demand for their services created by the proposed regulation.

Increase or Decrease of Investment in California

In this analysis, the annual direct costs of the proposed regulations are considered investment spending by the UIC operators. In this case, the investment spending mostly consists of purchases of contracted oil and gas services or equipment to meet the requirements of the proposed regulations. The indirect economic effect of that investment spending is expected to create $135-200 million per year over the first five years in value added (see Table 16). That value added represents the increase in Gross State Product (GSP) as a result of investment spending. However, this impact of the proposed regulations will be relatively insubstantial compared to California's roughly $2.6 trillion annual economy.[24]

Incentives for Innovation in Products, Materials, or Processes

Operators in California are constantly trying to reduce risk and increase efficiency, revenue, and profit by innovating. Operators have little to no control over the sales price of crude oil, so they must continually find ways to produce oil cheaply and efficiently if they want to raise the profit margins, particularly when the price of crude oil is relatively low. While the proposed regulations help to reduce some of the long-term risk by mandating testing and providing robust standards for underground injection control projects, it also narrows the profit margins in the short-term. But large and mid-sized operators have historically found some way to increase efficiency along the production chain, particularly through better technologies and outsourcing.[25] Oil and gas producers and the service contractors will continue to find innovations in technology and processes to remain competitive in a world market.

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[24] California Department of Finance, *Gross State Product*, May 11, 2017. <http://www.dof.ca.gov/Forecasting/Economics/Indicators/Gross_State_Product/>

[25] Abdel M. Zellou, "The Economic Benefits of Consolidation, Focus, and Partnership," *Innovations* Vol. VII, No. 4 (2015): 12-13.

Benefits

While there are large direct costs associated with the proposed regulations, there are also important social benefits that are less tangible and not easily measurable. Although this SRIA does not provide a cost accounting of the social benefits, it does discuss their importance.

Benefits to the Environment and Public Health

The proposed UIC rulemaking will benefit the public and environment by providing robust standards for underground injection control projects in California. The revised UIC regulations will modernize, clarify, and augment existing regulations to better protect underground sources of drinking water, improve worker safety, and reduce potential risks to public health and safety.

Groundwater

The fundamental purpose of these proposed regulations is to effectively protect sources and potential sources of water that can be of beneficial use including residential, agricultural, and commercial purposes. Groundwater is one of California's greatest natural resources. It provides 39 percent of the water supply to meet the state's total agricultural uses, 41 percent of the supply to meet the total urban water uses, and approximately 18 percent of the supply to meet the total managed wetlands uses. In drought years, groundwater usage increases and has contributed up to 46 percent of water used by California's farms, residents, and businesses.[26] Groundwater serves as a buffer against the impacts of drought and climate change and is a vital resource that should be protected and remain sustainable.

Contamination of groundwater supplies can render a groundwater basin unusable as a drinking water source, as well as for agricultural, industrial and other uses. Preventing groundwater contamination is much easier and far less expensive than remediating it. Thoroughly cleaning an aquifer can require cleansing the soil, sand, or rock containing the water source. For this reason, remediating polluted groundwater is very costly, can take years, and in many cases, is not technically or economically feasible.

For example, the cost and effort involved in the groundwater remediation at Superfund sites and Resource Conservation and Recovery Act (RCRA) corrective action sites, while not a perfect analog for remediation of the type of groundwater contamination that could potentially occur from UIC operations, offers an idea of how resource-intensive and challenging groundwater remediation efforts can be. In 2001, the U.S. EPA prepared a cost analysis for groundwater cleanup at 48 different Superfund sites and RCRA corrective action sites. The analysis focused on pump-and-treat (P&T) systems and permeable reactive barriers (PRBs). P&T involves extracting contaminated groundwater through recovery wells or trenches and treating the groundwater by aboveground processes, such as air stripping, carbon adsorption, biological reactors, or chemical precipitation. A PRB is a below-ground treatment zone of reactive material that degrades or immobilizes contaminants as groundwater flows through it. PRBs are installed as permanent, semi-permanent, or replaceable units across the flow path of a contaminated plume. The U.S. EPA analysis considered six main factors that affect the cost of P&T and PRB technology applications: (1) characteristics or properties of contaminants present, (2) system

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[26] Department of Water Resources, *California's Ground Water Update*, 2013. <https://www.water.ca.gov/LegacyFiles/waterplan/docs/groundwater/update2013/content/statewide/GWU2013_Combined_Statewide_Final.pdf>

design and operation, (3) source control, (4) hydrogeological setting, (5) extent of contamination, and (6) remedial goals. The analysis found that the costs varied significantly between sites and that many of the factors that affect costs are site-specific. The analysis concluded that the average remedial costs associated with P&T sites (32 sites) included $4.9 million total capital costs, and $770,000 operating costs per year. The average remedial costs associated with PRB sites (16 sites) included $730,000 total capital costs, with the per year operating costs unavailable due to insufficient data.[27] The remediation effort undertaken by either system can take many years to complete.

California's groundwater resources are already severely impacted by nitrate pollution, overdraft, underground storage tank contamination, and other threats. According to a 2013 State Water Resources Control Board Report, 680 community water systems that, prior to any treatment, relied on a contaminated groundwater source during the most recent California Department of Public Health (CDPH) compliance cycle (2002-2010). Of the 680 community water systems that rely on a contaminated groundwater source, 265 have served water that exceeded a public drinking water standard during the most recent CDPH compliance cycle (2002-2010).[28] Additionally, there are at least 21 groundwater basins that have been identified as subject to critical overdraft conditions.[29] Significant portions of these critically over drafted areas coincide with significant oil and gas production areas, including underground injection control activities. This makes rigorous protection of underground sources of drinking water all the more important.

The proposed underground injection control regulations serve to substantially mitigate risks to groundwater posed by UIC operations. The regulations provide for more thorough project review, more rigorous well mechanical integrity testing, improved fluid and chemical analysis, and several other provisions intended to ensure that risks to groundwater associated with UIC projects are minimized. The regulations provide a scientific, risked-based approach to prevent injection fluids from migrating beyond the approved injection zones and avoid contamination of underground sources of drinking water. Protecting ground water resources will help ensure that ground water resources are available for future generations of Californians.

Worker Safety

The regulations include provisions that will significantly improve worker safety. The proposed regulations include rigorous requirements for surface expression containment measures, prevention and response that will provide substantial safety benefits for workers. To emphasize safety, new language found in section 1724.11(a) states that "underground injection projects shall not result in any surface expression". Most surface expressions have occurred in areas that are situated far from homes and communities but they can still pose significant danger. In 2011, an oil field worker was killed when a

[27] U.S. EPA, *Cost Analyses for Selected Groundwater Cleanup Projects: Pump and Treat Systems and Permeable Reactive Barriers, Feb. 2001.* <https://www.epa.gov/sites/production/files/2015-04/documents/cost_analysis_groundwater.pdf>
[28] State Water Resources Control Board, *Communities that Rely on a Contaminated Groundwater Source for Drinking Water*, Jan. 2013. <https://www.waterboards.ca.gov/gama/ab2222/docs/ab2222.pdf>
[29] CA Department of Water Resources, *Critically Overdrafted Basins, Basins and Sub-Basins Subject to Conditions of Critical Overdraft*, last accessed 4/10/16. <http://wdl.water.ca.gov/groundwater/sgm/cod.cfm>

large surface expression occurred in a Kern County oilfield.[30] These proposed regulations emphasize the Division's intent to avoid any potential harm to workers or the public by including clear requirements addressing potential surface expressions.

Benefits to California Businesses and Consumers

Consistency for Operators

The proposed regulatory standards were developed to avoid confusion and provide transparency for all Division districts to enforce and advise, and operators to perform and report. These standards will provide clarity and consistency so there is no risk of misinterpretation of rules. Inconsistency and lack of clear guidelines in the past led to ad hoc operator practices and inadequate management of injection wells. Operators will now benefit from lack of confusion and increased transparency. Redundant or unnecessary work will be eliminated and thus will decrease operating costs. In addition, remediation required due to lack of a clear understanding of the regulations will now be avoided. Costs associated with both the redundancy of effort and remediation to amend will decrease, if not be eliminated, and will benefit operators in the long term.

Creation of Jobs

Jobs created by implementing the requirements of the proposed regulations will provide economic benefits to individuals, the public, communities, and both large and small businesses within the state by providing a robust market for professional services. Construction and service contracts for implementing the requirements in the regulations will increase. Professional staff positions that would be required include injection well engineering, technical services, field work testing, surveying, groundwater sampling and monitoring activities.

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[30] CA DOC, *How the DOGGR Regulates, Prevents, and Responds to Surface Expressions in California Oilfields,* Fact Sheet, 2018. <http://www.conservation.ca.gov/dog/Documents/2018_Fact_Sheet_Surface_Expression_DOGGR.pdf>

Alternatives

During the informal public comment process, the Division solicited potential alternatives to the requirements of the Discussion Draft. Based on Division staff expertise, historical information, and stakeholder/public comment, two alternatives have been selected for comparison to the proposed regulatory requirements and are discussed below. The alternatives selected include a requirement for more frequent mechanical integrity testing based the on MIT Part 2 proposed regulations (more burdensome) and a reduction in requirement for well-specific pressure gauges that would allow for manifold-based monitoring (less burdensome).

Alternative A: More Burdensome

Injection wells with mechanical integrity issues are vulnerable to fluid migration which can result in the contamination of USDWs and other natural resources. Regular testing for fluid migration behind the casing, tubing and packer is valuable as an indicator of flaws in the wellbore containment system. The proposed regulations expand upon existing testing requirements by specifying the procedures and frequency of testing for fluid migration. Specifically, testing procedures to satisfy the fluid migration requirements include either a radioactive tracer survey, noise log, or temperature survey.

Under proposed section 1724.10.2 Mechanical Integrity Testing Part Two, testing for fluid migration is required within three months after injection has commenced for the first time, with subsequent testing at differing frequencies depending on well type and configuration. Disposal injection wells must be tested at least once a year; waterflood injection at least once every two years; and steam flood and cyclic steam wells every two years, every three years, or every five years depending on the presence or absence of tubing and packer. These schedules were determined based on the level of risk associated with each type of well. The Division may also approve alternate testing frequencies, if appropriate, based on specific factors that affect risk including well construction, age of the well, quality of encasing cement, groundwater quality, and operational considerations.

Alternative A would require this Part Two testing on an annual basis for all wells, regardless of well type or configuration. This would be a significant change from the risk-based approach of the proposed regulatory requirements, and would increase the frequency of testing for all wells other than disposal injection wells. Alternative A assumes that the first-time test three months after commencement of injection would still be required and would satisfy the Year 1 testing requirement; it also assumes that the opportunity to seek Division approval for variance of testing frequency based on risk would no longer be an option.

Benefits

A higher frequency of testing would allow for earlier detection of potential well integrity issues. With earlier detection comes earlier investigation and mitigation, reducing the potential for a loss-of-containment incident. With the reduced potential for loss-of-containment comes reduced potential for contamination of USDWs and natural resources. Reduction in loss-of-containment incidents would also provide greater protection to public health and safety as well as the surrounding environment. A single regulatory requirement for all wells would reduce regulatory confusion and provide the consistency that public and environmental groups believe is needed for effective regulation.

Costs to Industry

Under Alternative A, all injection wells would be subject to annual testing rather than testing on a risk-based schedule. This would increase the cost to industry, with different well types and configurations differently affected. The cost for each additional test is assumed to be the same as the cost used for the initial testing requirement as discussed in this SRIA and calculated below.

Although this Alternative would likely include an additional number of testing requirements each year due to injection pressure anomalies or if required by the Division, there is no way to quantitatively predict the increase in the actual number of these activities, so while additional costs are recognized, they are not calculated. In addition, because the Division does not yet have any data indicating which operators would request an "alternative" testing frequency, the cost to those operators who might have obtained approved variance under the proposed regulations is assumed to be based on the default requirement for each well type.

Costs are calculated on yearly testing of all wells by category on a yearly basis as shown in Table 17. Since this Alternative does not recognize testing requirements to differentiate between those wells with tubing and packer and those without, all costs are determined by well type alone.

Table 17. Alternative A Costs: Annual Mechanical Integrity Part Two Testing

Well Type	Proposed Reg. Frequency	Alt. A Frequency	Alt. A Change	Count of Wells	Annual Cost, per Well	Alt. A Total Annual Cost
Disposal Injection	Annual	Annual	No Change	1,219	N/A	N/A
Waterflood	Once Every 2 Years	Annual	Add'l 1 Year	5,412	$5,579	$30,193,548
Cyclic Steam	Once Every 3 Years	Annual	Add'l 2 Years	25,346	$5,579	$141,405,334
Steamflood	Once Every 2 Years	Annual	Add'l 1 Year	5,478	$5,579	$30,561,762
Total	-	-	-	37,455	-	$202,160,644

Note: Does not include pressure maintenance wells.

Reason for Rejection

Alternative A does not consider the potential risk associated with integrity testing. Well equipment may have to be removed to facilitate the testing. This removal and replacement can damage the casing due to metal-to-metal contact and the testing equipment can cause damage as it travels through the wellbore. The damage that can result from testing accelerates integrity loss in the well with a greater potential for loss-of-containment incidents. The risk-based testing frequency of the proposed regulations better accounts for this damage by ensuring the testing takes place as frequently as needed to ensure integrity, based on risk associated with well configuration, environmental, and operational conditions.

In addition, throughout the regulation development process, industry has expressed concern that a "one size fits all" approach is not justified when all wells don't have the same risk of failure, and all wells don't pose the same risk to health and natural resources in the event of failure. For example, a well that is used less frequently, such as a cyclic steam well, may be subject to less wear and tear than a well that is used to inject on a daily basis. Similarly, a well in the middle of an oil field miles from any human habitation does not pose the same risk to the environment and public health as a well that sits in an urban environment or very near a USDW. Thus, the risk-based approach ensures that wells are not subject to the risk associated with testing when it is not justified based on the actual risk they pose.

With the higher costs associated with the higher frequency of annual testing as well as the unknown costs associated with additional investigations and mitigations, Alternative A would be significantly burdensome to operators. Although it would catch integrity issues earlier in their formation, the potential for damage to wellbore integrity caused by testing is not justified when the Division's current scientific knowledge demonstrates that integrity issues develop differently in different types of wells and conditions. Thus, the Division does not currently see a regulatory need for the data sufficient to justify the more burdensome cost of increased testing.

Alternative B: Less Burdensome

The initial draft of the proposed regulations required the installation of well-specific injection pressure gauges that are continuously recording at all times during injection. During the informal public comment process, the Division received recommendations for the removal of this well-specific requirement. Instead, commenters proposed consistency with 40 CFR § 146.23(b)(5), which indicates that "separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring."

A manifold monitoring system is generally used to ensure that required pressures and flows are maintained for safe and proper operation consistent with system design.[31] A meter or gauge is placed on the manifold between the pump and laterals which lead to multiple wells, measuring the flow and pressure of the fluid moving through the manifold. Many different types of meters may be used, including flow meters, pressure differential meters, rotating mechanical meters, Bourdon Gauges and transducers.[32] More recently, the development of a device to manage phase splitting in steam distribution systems, known as the SpliTigator™, provides an additional tool for manifold monitoring of injection wells.[33]

Since these original comments were received, the proposed regulations have been updated to require that "well-specific pressure shall be continuously recorded at all times that a well is classified as an active injection well." Thus, Alternative B considers the impact of allowing for less burdensome manifold monitoring as recommended by commenters, rather than continuous well-specific recording of injection pressure as currently proposed. Under Alternative B, operators would be permitted to have a gauge on a manifold that monitors injection pressure of multiple wells and would have no specific requirement to obtain or use data from the gauge. This is consistent with current regulatory practice, where the Division must make a specific request for pressure gauge data.

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[31] U.S. EPA Office of Drinking Water, *Underground Injection Control Guidance Document on Evaluation of Injection Well Manifold Monitoring Systems*, EPA 570/9-85-006 November 1985, pg. 3. <https://nepis.epa.gov/>

[32] *Id*. at 5-8.

[33] Berger, E.L., Kolthoff, K.W., Schrodt, J.L. G., Long, S.L., & Pauley, J.C. (1997, January 1). *The SpliTigator™: A Device for the Mitigation of Phase Splitting*. Society of Petroleum Engineers. Doi: 10.2118/37516-MS. <https://www.onepetro.org/conference-paper/SPE-37516-MS>

Benefits

The primary benefit of Alternative B is that pressure monitoring can be performed for less cost and often using equipment that is already in place. For example, U.S. EPA found that a central monitoring point will reduce project costs related to purchasing, operating, and maintaining monitoring equipment.[34] This makes sense: gauges on the manifold rather than on each well means fewer gauges with a corresponding reduction in the cost of calibrating and maintaining those gauges over time.

The SpliTigator™ serves a purpose to improve steam distribution across a manifold, so an operator could also gain the benefit of monitoring with a device designed primarily to improve production. This reduces cost because the monitoring is performed with a device being used to maximize steam distribution efficiency. Thus, for operators already using the SpliTigator™ or other similar technologies, there would be no cost associated with meeting the requirements of Alternative B.

Finally, cost would also be reduced because the monitoring requirement would not be continuous. Where the Division must ask for a reading from the gauge, no costs associated with regulator monitoring of the device are incurred. Thus, as compared to the proposed regulatory requirements, the manifold monitoring of Alternative B would have reduced or even have no cost to current operators depending on their equipment configuration.

Costs to Industry

Alternative B would have lower costs over the lifetime of the regulations because operators would be required to purchase and maintain fewer gauges. Where existing production equipment provides an opportunity to access injection pressure data without purchasing and installation additional gauges, Alternative B saves the entirety of the cost associated with compliance with this requirement.

In addition, the use of gauges designed to monitor flow and pressure at the manifold are common throughout the industry as they are used to ensure that production efficiency is being maintained. Division enforcement and management staff believe that it is reasonable to assume that all operators already use some type of manifold meter as part of their production systems. Based on this experience, it is likely that Alternative B would have little to no cost for existing operators, so specific costs associated with Alternative B have not been calculated and a status quo is assumed.

Reasons for Rejection

The greatest reason for rejection of manifold monitoring is that it does not allow for monitoring of individual wells. Although a pressure change on the manifold can be an indicator of a problem, it does not provide enough information to identify which well has the problem or even to determine if the problem lies with the wells or with the larger manifold system. More importantly, because the volume of flow within a manifold system is greater than an individual flow line, the ability of a gauge to detect small changes in pressure is reduced; this problem can be exacerbated by larger volumes of fluid being injected into larger numbers of wells across a single manifold.[35]

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[34] U.S. EPA Office of Drinking Water, *Underground Injection Control Guidance Document on Evaluation of Injection Well Manifold Monitoring Systems*, EPA 570/9-85-006 November 1985, pg. 3. <https://nepis.epa.gov/>

[35] U.S. EPA Office of Drinking Water, *Underground Injection Control Guidance Document on Evaluation of Injection Well Manifold Monitoring Systems*, EPA 570/9-85-006 November 1985. <https://nepis.epa.gov/>

In addition, similar to the current regulatory system, under Alternative B, Division staff would still have to specifically request a reading of pressure data, providing a sparse data record and limiting the ability to effectively investigate incidents such as surface expressions or reports of groundwater contamination. In contrast, continuous monitoring allows for ongoing verification of injection pressures and analysis of pressure over time, providing more tools for regulatory enforcement and scientific data to improve well management and reduce loss-of-containment incidents.

Alternatives – Conclusion

In summary, Alternative A is rejected because the cost would be excessively burdensome to operators without accounting for the actual risk associated with specific well configurations and environmental conditions. Alternative B is rejected because it does not achieve the regulatory goal of providing for continuous monitoring of injection pressure to ensure regulatory compliance and well integrity. Both alternatives demonstrate that the proposed regulations achieve their regulatory purpose without excessive burden to the operator.

Fiscal Impacts

Local Government

Underground injection wells are governed by state and federal laws. The regulations would decrease the risk of ground water contamination that could result in costly alternative water sources being developed. They will also likely reduce incidences of surface expressions that can result in the potential need for emergency response and other related services provided by local government. Therefore, the proposed regulations will not affect local government.

Department of Conservation

In addition to reviewing each UIC project, Division staff will ensure testing requirements are met, projects monitored, and compliance analyses performed. However, in recognition of past inadequate staffing for the UIC Program, additional positions were requested and granted in several Budget Change Proposals (BCPs) and Finance Letters (FLs). In response to the staff shortage, the Division received 17 positions for fiscal year (FY) 2010-11 and 18 positions for FY 2011-12. Additional requests were made for 9 positions for FY 2011-12 and 21 positions for FY 2012-13. Twenty-three positions were requested for FY 2015-16 to work on aquifer exemptions, the project by project review, and other UIC related activities to ensure compliance with the Safe Drinking Water Act. For FY 2018-19, the Division requested 21 additional field inspection staff. The job duties include witnessing UIC well tests and inspecting UIC projects.

Other State Agencies

Other state agencies should not incur substantial, if any, expense related to these proposed regulations since the Division has primary jurisdiction over UIC projects.

However, the Water Board must review and concur with the Division's approval of UIC projects and has requested additional personnel as the program is undergoing regulation, review, and renewal efforts. Based on a spring Finance Letter in 2015, the Water Board received a total of 19 positions to perform activities in support of the Division's expanding UIC Program. In addition, a Water Board BCP for FY 2014-15 requested 14 positions yearly through a funding shift from the Division to supplement the UIC increased activities and workload.

Conclusion

The proposed UIC regulations are an important, risk-based approach to renew and update the Division's rules for enhanced oil recovery and produced water disposal. Estimations for the average yearly economic impact for the first five years of implementation of these proposed regulations is roughly $185 million for direct costs. The average economic impact of this direct spending is expected to result in about $268 million per year in gross output over the first five years of implementation; an average increase of about 1,099 jobs per year for employment; an average of nearly $74,000 per year in earnings; and an average of more than $159 million in gross state product per year.

This economic analysis took a conservative approach and economic impact estimates should be viewed in the context of the assumptions used to develop the estimates. When looking at these results a few key assumptions should be kept in mind. First, this analysis may overestimate the number of active wells in the state subject to the regulatory requirements. For the purposes of estimating the costs, the Department only counted active injection wells that have a record of injection within the past six years. This resulted in a population of 37,563 UIC wells. While wells that are inactive for over 24 months are considered idle and will be subject to idle well regulations rather than UIC well regulations, the Department opted to include a larger subset of wells in order to account for the possibility that increasing oil prices and recently proposed revisions to existing regulations governing the testing and management of idle wells may result in some wells being returned to production or new wells being drilled.

Second, the analysis largely assumes that operators will comply with the default requirements explicitly laid out in the regulations. As such, the cost estimates do not account for flexibility which would allow operators to propose alternative, less costly approaches or schedules.

Third, the RIMS II model does not take into account operator behavior. This type of input-output model does not consider, estimate, or speculate on changes in behavior on regulated entities. As such, it does not consider innovations operators may undertake to reduce costs, changes in scheduling of maintenance and testing so they occur simultaneously when a rig is on a well, or changes in oil and gas production that may be associated with taking wells on and off-line as they undergo testing required by the regulations.

While these types of assumptions certainly affect the estimates, they were necessary in order to complete this type of analysis and ensure a full consideration of possible costs.

In the short-term, the regulated industry is expected to see a drop in profit margins as operators meet the proposed requirements. Small operators are particularly vulnerable to the regulatory cost burden and, in some cases, may be forced to exit the industry. The state may experience slightly lower production over the first few years of the proposed regulations as operators divert spending from direct production and small operators stop production altogether. However, any reduction in production would be difficult to distinguish from the continuing decline in oil production in California resulting from market forces and the continued depletion of known, currently economically accessible oil and gas reserves. The Division expects the industry to find innovative ways to adjust to the cost burden resulting from the proposed regulations.

APPENDIX A: Survey

Department of Conservation

CALIFORNIA CONSERVATION

Industry Costs for Underground Injection Control

Survey Respondent Profile

The Department of Conservation is gathering cost estimates associated with the reporting, testing, and proper maintenance of California's active underground injection wells. The cost estimates will be used to determine the economic impact of the Department's proposed underground injection control regulations.

Cost information will be provided as an aggregate cost without specific attribution to respondents. **The report will not reveal the names of the survey participants nor will the respondents' names be tied to their specific responses.**

1. What is your role in the oil and gas industry?

- O Owner Operator or Contract Operator
- O Contractor (including consultant and service company)

Operator Profile

2. If you are an <u>operator</u>, in which of the following counties do you have oil and gas operations? (Check all that apply)

- [ ] Alameda County
- [ ] Alpine County
- [ ] Amador County
- [ ] Butte County
- [ ] Calaveras County
- [ ] Colusa County
- [ ] Contra Costa County
- [ ] Del Norte County
- [ ] El Dorado County
- [ ] Fresno County
- [ ] Glenn County
- [ ] Humboldt County
- [ ] Imperial County
- [ ] Inyo County
- [ ] Kern County
- [ ] Kings County
- [ ] Lake County
- [ ] Lassen County
- [ ] Los Angeles County
- [ ] Madera County
- [ ] Marin County
- [ ] Mariposa County
- [ ] Mendocino County
- [ ] Merced County
- [ ] Modoc County
- [ ] Mono County
- [ ] Monterey County
- [ ] Napa County
- [ ] Nevada County
- [ ] Orange County
- [ ] Placer County
- [ ] Plumas County
- [ ] Riverside County
- [ ] Sacramento County
- [ ] San Benito County
- [ ] San Bernardino County
- [ ] San Diego County
- [ ] San Francisco County
- [ ] San Joaquin County
- [ ] San Luis Obispo County
- [ ] San Mateo County
- [ ] Santa Barbara County
- [ ] Santa Clara County
- [ ] Santa Cruz County
- [ ] Shasta County
- [ ] Sierra County
- [ ] Siskiyou County
- [ ] Solano County
- [ ] Sonoma County
- [ ] Stanislaus County
- [ ] Sutter County
- [ ] Tehama County
- [ ] Trinity County
- [ ] Tulare County
- [ ] Tuolumne County
- [ ] Ventura County
- [ ] Yolo County
- [ ] Yuba County

Comments:

3. If you are an __operator__, what type of injection wells do you own or operate? (Check all that apply)

O Disposal
O Water Flood
O Steam Flood
O Cyclic Steam
O Pressure Maintenance

Comments:

4. If you are an __operator__, how many active injection wells do you currently own/operate?

O Less than 10
O 10 to 100
O 101 to 500
O More than 500

Comments:

5. If you are an __operator__, how many active underground injection projects do you currently oversee?

Contractor Profile

6. If you are a __contractor__, which of the following services do you or could you provide to the oil and gas operators? (Check all that apply)

O Engineering and/or geologic studies, including all related mapping and diagramming requirements
O Testing of wells
O IT and data management services
O Other (please specify)

Section 1724.7. Project Data Requirements

An underground injection project needs to be supported by data filed with the Division. Data must demonstrate to the Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection and that the underground injection project will not cause damage to life, health, property, or natural resources. If you are a contractor and you do not provide the contract services referred to in the questions below, leave the answer blank.

7. Section 1724.7(a)(1) of the proposed regulations requires an engineering and geological study for every underground injection project, demonstrating that injected fluid will not migrate out of the approved zone or zones.

To what extent are the proposed data requirements already available for submission to the Division?

	Fully available	Partially available	Not yet available
Reservoir characteristics of each injection zone, for all projects:	○	○	○
Reservoir fluid data for each injection zone, for all projects:	○	○	○
A map of the area of review showing the location and status of all wells, for all projects:	○	○	○
Casing diagrams, in accordance with proposed section 1724.7.1, for all injection wells:	○	○	○
Identification of all wells within the area of review that do not penetrate the injection zone, for all projects:	○	○	○
Maps of the locations for any subsurface industrial activities not associated with oil and gas production, for all projects:	○	○	○

Comments:

8. In the previous question, if you selected "partially available" or "not yet available" for any of the listed requirements, please provide an average cost estimate, either per project or per injection well as indicated below, for meeting the requirements in full:

Reservoir characteristics of each injection zone, cost per project ($):	
Reservoir fluid data for each injection zone, cost per project ($):	
A map of the area of review showing the location and status of all wells, cost per project ($):	
Casing diagrams, in accordance with proposed section 1724.7.1, cost per injection well ($):	
Identification of all wells within the area of review that do not penetrate the injection zone, cost per project ($)	
Maps of the locations for any subsurface industrial activities not associated with oil and gas production, cost per project ($):	

9. Section 1724.7(a)(2) of the proposed regulations requires a geologic study for each underground injection project.

To what extent are the proposed data requirements already available for submission to the Division?

	Fully available	Partially available	Not yet available
Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area, indicating known faults and other lateral containment features:	○	○	○
At least one geologic cross section in the project area through at three injection wells, including one injection well:	○	○	○
Representative electric log to a depth below the deepest producing zone, identifying all geologic units, formations, USDWs, freshwater aquifers, and oil or gas zones:	○	○	○

Comments:

10. In the previous question, if you selected "partially available" or "not yet available" for any of the listed requirements, please provide an average cost estimate, per project, for meeting the requirements in full:

Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area, indicating known faults and other lateral containment features, cost per project ($):	
At least one geologic cross section in the project area through at least three wells, including one injection well, cost per project ($):	
Representative electric log to a depth below the deepest producing zone, identifying all geologic units, formations, USDWs, freshwater aquifers, and oil or gas zones, cost per project ($):	

11. Section 1724.7(a)(3) of the proposed regulations requires an <u>injection plan</u>, for all underground injection projects.

To what extent are the proposed data requirements already available for submission to the Division?

	Fully available	Partially available	Not yet available
Source and analysis of the injection fluid, in accordance with proposed section 1724.7.2:	◯	◯	◯

Comments:

12. In the previous question, if you selected "partially available" or "not yet available" for any of the listed requirements, please provide an average cost estimate, <u>per project</u>, for meeting the requirements <u>in full</u>:

Source and analysis of the injection fluid, in accordance with proposed section 1724.7.2, cost <u>per project</u> ($):

13. Section 1724.7(a)(4) of the proposed regulations requires the results of all <u>step rate tests</u>, conducted in accordance with proposed section 1724.7.3, for each injection well that is part of the underground injection project.

To what extent do you meet the requirements of the step rate tests, conducted in accordance with proposed section 1724.7.3, for your injection wells?

	Fully met	Partially met	Not yet met
Step rate tests, conducted in accordance with proposed section 1724.7.3, for each injection well that is part of the underground injection project:	◯	◯	◯

Comments:

14. In the previous question, if you selected "partially met" or "not yet met" for the listed requirement, please provide an average cost estimate, <u>per injection well</u>, for meeting the step rate testing requirement <u>in full</u>:

Step rate tests, conducted in accordance with proposed section 1724.7.3, for each injection well that is part of the underground injection project, cost <u>per injection well</u> ($):

15. Section 1724.7(a)(6) of the proposed regulations requires <u>additional data for large, unusual, or potentially hazardous projects</u>.

To what extent are the proposed data requirements already available for submission to the Division?

	Fully available	Partially available	Not yet available
3-D maps:	○	○	○
Computer geologic models:	○	○	○

Comments:

16. In the previous question, if you selected "partially available" or "not yet available" for any of the listed requirements, please provide an average cost estimate, <u>per project</u>, for meeting the requirement <u>in full</u>:

3-D maps, cost <u>per project</u> ($):

Computer geologic models, cost <u>per project</u> ($):

17. Section 1724.7(c) of the proposed regulations requires that all <u>data in this section shall be submitted electronically in a digital format</u>. Digital data is a specific form of electronic data that can be loaded into databases and read or interpreted by various programming languages (electronic data such as PDF files and image scans <u>do not</u> meet this requirement).

To what extent are the required data in the proposed regulations available in a digital format?

	Fully available	Partially available	Not yet available
Digitally formatted project data requirements:	○	○	○

Comments:

18. In the previous question, if you selected "partially available" or "not yet available" for the listed requirement, please provide an average cost estimate, <u>per project</u>, for meeting the requirement <u>in full</u>:

Conversion of data into a digital format for submission to the Division, cost <u>per project</u> ($):

1724.7.10. Filing, Notification, Operating, and Testing Requirements

19. Section 1724.7.10(f) of the proposed regulations requires that all injection piping, valves, and facilities shall meet or exceed design standards for the maximum allowable injection pressure, and shall be maintained in a safe and leak-free condition.

To what extent do you meet the requirement that your injection piping, valves, and facilities meet or exceed design standards for the maximum allowable injection pressure and are maintained in a safe and leak-free condition?

	Fully met	Partially met	Not yet met
Injection piping, valves, and facilities meet or exceed design standards and are maintained in a safe and leak-free condition:	○	○	○

Comments:

20. In the previous question, if you selected "partially met" or "not yet met" for the listed requirement, please provide an average cost estimate, <u>per project</u>, for meeting the requirement <u>in full</u>:

Injection piping, valves, and facilities meet or exceed design standards and are maintained in a safe and leak-free condition, cost <u>per project</u> ($):

21. Section 1724.7.10(g) of the proposed regulations requires that all injection wells shall be equipped with tubing and packer set immediately above the approved zone of injection.

Approximately what <u>percentage</u> of your injection wells already meet this requirement (%)?

22. Please provide an average cost estimate, <u>per injection well</u>, for properly equipping an injection well with tubing and packer in accordance with the requirement in proposed section 1724.7.10(g)?

Proper tubing and packer requirements, cost <u>per injection well</u> ($)?

23. Comments regarding the cost of the proposed regulation, per proposed section 1724.7.10(g):

8

1724.7.10.1 Mechanical Integrity Testing Part One - Casing Integrity

Mechanical integrity testing must be performed on all injection wells to ensure that the injected fluid is confined to the approved zone or zones. Mechanical integrity testing shall consist of a two- part demonstration in accordance with sections 1724.10.1 and 1724.10.2.

24. Section 1724.7.10.1 of the proposed regulations requires that, prior to commencing injection operations, each injection well must pass a pressure test of the casing to determine the absence of leaks.

Which of the following casing integrity tests do you expect to perform for the majority of your injection wells?

O Casing Pressure Test, in accordance with proposed section 1724.7.10.1(a)
O Annulus Pressure Monitoring, in accordance with proposed section 1724.7.10.1(b)
O Other (please specify)

25. Please provide an average cost estimate, <u>per injection well</u>, to perform the casing integrity test selected in the previous question ($)?

Casing integrity test, cost <u>per injection well</u> ($):

26. Comments regarding the cost of the proposed regulation, per proposed section 1724.7.10.1:

1724.7.10.1 Mechanical Integrity Testing Part Two – Fluid Migration Behind Casing, Tubing, or Packer

27. Section 1724.7.10.2 of the proposed regulations requires that additional testing take place to demonstrate that there is no fluid migration behind the casing, tubing, or packer.

Which of the following methods do you expect to employ for additional testing, in accordance with proposed section 1724.10.2? (select one)

O Radioactive Tracer
O Temperature Survey
O Noise Log
O Other (please specify)

28. Please provide an average cost estimate, per injection well, to perform the additional testing method selected in the previous question ($)?

Additional testing method, cost per injection well ($):

29. Comments regarding the cost of additional testing, per proposed section 1724.7.10.2:

10

Comments

30. If you have any additional comments, please provide them in the space below:

APPENDIX B: Direct Costs Associated with Proposed UIC Regulations

Direct Cost Category	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	$2,184,458	$2,320,208	$135,751	$135,751	$135,751
Map of underground disposal horizons, mining, and other subsurface industrial activities	$941,333	$1,015,169	$73,836	$73,836	$73,836
Compendium of Information on Wells in Area of Review	$2,092,658	$4,352,715	$167,400	$167,400	$167,400
Casing Diagrams	$3,803,254	$4,340,254	$537,000	$537,000	$537,000
Reservoir Characteristics	$1,614,533	$1,872,833	$258,300	$258,300	$258,300
Reservoir Fluid Data	$1,850,535	$2,029,041	$178,506	$178,506	$178,506
Structural Contour Map	$2,651,873	$2,908,049	$256,176	$256,176	$256,176
Geologic Cross Sections	$2,673,511	$2,845,756	$172,245	$172,245	$172,245
Electric Log	$1,525,410	$1,668,942	$143,532	$143,532	$143,532
Fluid Analysis	$934,870	$1,006,618	$697,550	$697,550	$697,550
Step-Rate Tests	$14,917,266	$16,392,600	$1,475,334	$1,475,334	$1,475,334
Electronic Data Submittal/Data Formatting	$13,413,893	$13,413,893	$0	$0	$0
Chemical Disclosure	$77,000	$79,000	$81,000	$83,000	$85,000
Re-Abandon P&A'd Wells within Area of Review	$19,937,813	$20,876,063	$938,250	$938,250	$938,250
Pressure Monitoring & Recording Device	$7,039,200	$7,308,000	$268,800	$268,800	$268,800
Tubing and Packer	$335,750	$572,750	$237,000	$237,000	$237,000
Cyclic Steam Record Retention	$387,000	$129,000	$129,000	$129,000	$129,000
Pressure Testing - MIT 1	$66,082,635	$66,082,635	$66,082,635	$66,082,635	$66,082,635
Cyclic Steam Wells - MIT 2	$70,702,667	$76,823,726	$76,823,726	$76,823,726	$76,823,726
Steam flood wells (without tubing and packer) - MIT 2	$7,884,801	$8,035,434	$8,035,434	$8,035,434	$8,035,434
Surface Expression Prevention	$0	$420,000	$120,000	$540,000	$240,000
Total	**$221,050,456**	**$234,492,683**	**$156,811,474**	**$157,233,474**	**$156,935,474**

APPENDIX C: Gross Output Impact by Category of Spending

Category of Spending	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	$3,392,899	$3,603,748	$210,848	$210,848	$210,848
Map of underground disposal horizons, mining, and other subsurface industrial activities	$1,462,078	$1,576,760	$114,682	$114,682	$114,682
Compendium of Information on Wells in Area of Review	$3,250,316	$6,760,637	$260,006	$260,006	$260,006
Casing Diagrams	$5,907,214	$6,741,282	$834,068	$834,068	$834,068
Reservoir Characteristics	$2,507,692	$2,908,883	$401,192	$401,192	$401,192
Reservoir Fluid Data	$2,449,923	$2,686,247	$236,324	$236,324	$236,324
Structural Contour Map	$4,118,888	$4,516,781	$397,893	$397,893	$397,893
Geologic Cross Sections	$4,152,497	$4,420,028	$267,530	$267,530	$267,530
Electric Log	$2,019,490	$2,209,512	$190,022	$190,022	$190,022
Fluid Analysis	$1,452,040	$1,563,479	$1,083,435	$1,083,435	$1,083,435
Step-Rate Tests	$19,748,968	$21,702,163	$1,953,195	$1,953,195	$1,953,195
Electronic Data Submittal/Data Formatting	$21,420,645	$21,420,645	$0	$0	$0
Chemical Disclosure	$101,940	$104,588	$107,236	$109,884	$112,532
Re-Abandon P&A'd Wells within Area of Review	$26,395,670	$27,637,819	$1,242,149	$1,242,149	$1,242,149
Pressure Monitoring & Recording Device	$10,529,235	$10,931,306	$402,071	$402,071	$402,071
Tubing and Packer	$502,215	$856,719	$354,505	$354,505	$354,505
Cyclic Steam Record Retention	$618,000	$206,000	$206,000	$206,000	$206,000
Pressure Testing - MIT 1	$87,486,800	$87,486,800	$87,486,800.21	$87,486,800	$87,486,800
Cyclic Steam Wells - MIT 2	$93,603,261	$101,706,931	$101,706,931	$101,706,931	$101,706,931
Steam flood wells (without tubing and packer) - MIT 2	$10,438,688	$10,638,111	$10,638,111	$10,638,111	$10,638,111
Surface Expression Prevention	$0	$628,236	$179,496	$807,732	$358,992
Total	**$301,558,461**	**$400,243,859**	**$211,865,175**	**$212,496,059**	**$212,049,967**

APPENDIX D: Earnings Impact by Category of Spending

Category of Spending	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	$1,315,699	$1,397,461	$81,763	$81,763	$81,763
Map of underground disposal horizons, mining, and other subsurface industrial activities	$566,965	$611,436	$44,471	$44,471	$44,471
Compendium of information on wells in Area of Review	$1,260,408	$2,621,640	$100,825	$100,825	$100,825
Casing Diagrams	$2,290,700	$1,128,007	$323,435	$323,435	$323,435
Reservoir Characteristics	$972,433	$1,128,007	$155,574	$155,574	$155,574
Reservoir Fluid Data	$721,524	$281,322	$109,687	$42,767	$16,675
Structural Contour Map	$1,597,223	$962,007	$579,417	$348,983	$210,192
Geologic Cross Section	$1,610,256	$1,713,999	$103,743	$103,743	$103,743
Electric Log	$594,757	$650,720	$55,963	$55,963	$55,963
Fluid Analysis	$563,072	$606,286	$420,134	$420,134	$420,134
Step-Rate Tests	$5,816,242	$6,391,475	$575,233	$575,233	$575,233
Electronic data submittal/data formatting	$5,932,965	$5,932,965	$0	$0	$0
Chemical Disclosure	$30,022	$30,802	$31,582	$32,362	$33,142
Reabandon P&A wells that don't meet standard	$7,773,753	$8,139,577	$365,824	$365,824	$365,824
Pressure Monitoring & Recording Device	$2,684,751	$2,787,271	$102,520	$102,520	$102,520
Tubing and Packer	$128,055	$218,447	$90,392	$90,392	$90,392
Cyclic Steam Record Retention	$171,170	$57,057	$57,057	$57,057	$57,057
Pressure Testing - MIT 1	$25,765,619	$25,765,619	$25,765,619.31	$25,765,619	$25,765,619
Cyclic Steam Wells-MIT 2	$27,566,970	$29,953,571	$29,953,571	$29,953,571	$29,953,571
Steam flood wells (without tubing and packer)-MIT 2	$3,074,284	$3,133,016	$3,133,016	$3,133,016	$3,133,016
Surface Expression Prevention	$0	$160,188	$45,768	$205,956	$91,536
Total	**$90,436,866**	**$93,670,873**	**$62,095,594**	**$61,959,207**	**$61,680,684**

APPENDIX E: Employment Impact by Category of Spending

Category of Spending	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	20	21	1	1	1
Map of underground disposal horizons, mining, and other subsurface industrial activities	8	9	1	1	1
Compendium of information on wells in Area of Review	19	39	2	2	2
Casing Diagrams	34	39	5	5	5
Reservoir Characteristics	15	17	2	2	2
Reservoir Fluid Data	11	12	1	1	1
Structural Contour Map	24	26	2	2	2
Geologic Cross Section	24	26	2	2	2
Electric Log	9	10	1	1	1
Fluid Analysis	8	9	6	6	6
Step-Rate Tests	85	94	8	8	8
Electronic data submittal/data formatting	94	94	0	0	0
Chemical Disclosure	0	0	0	0	0
Reabandon P&A wells that don't meet standard	114	119	5	5	5
Pressure Monitoring & Recording Device	45	47	2	2	2
Tubing and Packer	2	4	2	2	2
Cyclic Steam Record Retention	3	1	1	1	1
Pressure Testing - MIT 1	378	378	378	378	378
Cyclic Steam Wells-MIT 2	405	440	440	440	440
Steam flood wells (without tubing and packer)-MIT 2	45	46	46	46	46
Surface Expression Prevention	0	3	1	3	2
Total	**1,343**	**1,433**	**906**	**908**	**906**

APPENDIX F: Value Added (GSP) by Category of Spending

Category of Spending	Year 1	Year 2	Year 3	Year 4	Year 5
Map of Area of Review	$1,854,604	$1,969,857	$115,252	$115,252	$115,252
Map of underground disposal horizons, mining, and other subsurface industrial activities	$799,191	$861,878	$62,687	$62,687	$62,687
Compendium of information on wells in Area of Review	$1,776,666	$3,695,455	$142,123	$142,123	$142,123
Casing Diagrams	$3,228,962	$3,684,875	$455,913	$455,913	$455,913
Reservoir Characteristics	$1,370,738	$1,590,035	$219,297	$219,297	$219,297
Reservoir Fluid Data	$1,600,528	$1,754,918	$154,390	$154,390	$154,390
Structural Contour Map	$2,251,440	$2,468,933	$217,493	$217,493	$217,493
Geologic Cross Section	$2,269,811	$2,416,047	$146,236	$146,236	$146,236
Electric Log	$1,319,327	$1,443,468	$124,141	$124,141	$124,141
Fluid Analysis	$793,705	$854,619	$592,220	$592,220	$592,220
Step-Rate Tests	$12,901,943	$14,177,960	$1,276,016	$1,276,016	$1,276,016
Electronic data submittal/data formatting	$11,399,126	$11,399,126	$0	$0	$0
Chemical Disclosure	$66,597	$68,327	$70,057	$71,787	$73,517
Reabandon P&A wells that don't meet standard	$17,244,214	$18,055,706	$811,492	$811,492	$811,492
Pressure Monitoring & Recording Device	$4,272,794	$4,435,956	$163,162	$163,162	$163,162
Tubing and Packer	$203,800	$347,659	$143,859	$143,859	$143,859
Cyclic Steam Record Retention	$328,873	$109,624	$109,624	$109,624	$109,624
Pressure Testing - MIT 1	$57,154,871	$57,154,871	$57,154,870.84	$57,154,871	$57,154,871
Cyclic Steam Wells-MIT 2	$61,150,737	$66,444,841	$66,444,841	$66,444,841	$66,444,841
Steam flood wells (without tubing and packer)-MIT 2	$6,819,564	$6,949,847	$6,949,847	$6,949,847	$6,949,847
Surface Expression Prevention	$0	$254,940	$72,840	$327,780	$145,680
Total	**$188,807,492**	**$200,138,941**	**$135,426,360**	**$135,683,030**	**$135,502,659**