AB 1420 PIPELINE TESTING REGULATIONS

45-DAY PUBLIC COMMENT PERIOD

COMMENT SUMMARIES AND RESPONSES

DEPARTMENT OF CONSERVATION

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

INTRODUCTION

The following comments, objections, and recommendations were made regarding the proposed action during a public comment period beginning September 22, 2017 and ending November 10, 2017. During that public comment period, two public comment hearings were conducted, one in Los Angeles on November 8, and one in Bakersfield on November 9.

Over the course of the public comment period, the Division of Oil, Gas, and Geothermal Resources (Division) received a variety of public comments via email and public comment hearing. To facilitate the process of reviewing and responding to comments, the Division assigned to each comment a unique numerical signifier. This signifier consists of three components: first, a unique code number assigned to each commenter entity; second, a separating hyphen; third, a sequential number assigned to each comment from the identified commenter entity.

The comment summaries are categorized by the sections of the proposed regulations, and are arranged in groups under one or more corresponding numerical signifiers. Responses to comments appear below the respective comment summaries, in italicized text.

COMMENTERS

Number	Name and/or Entity
0001	California Resources Corporation
0002	California Independent Petroleum Association
0003	Clean Water Action
0004	E & B Resources
0005	Western States Petroleum Association
0006	Marc Traut
0007	Independent Oil Producers Agency
0008	Chevron

COMMENT SUMMARIES AND RESPONSES

COMMENTS IN SUPPORT

0003-1
The commenter supports the proposed regulations to implement AB 1420 (Salas), as that bill was supported during the legislative process. Pipelines used by the oil and gas industry are located throughout California, and have unfortunately failed to protect the public and environment in the past. More is needed to ensure that these pipelines are safe. These regulations increase inspections of active pipelines for high risk pipelines in sensitive areas near homes, schools, and waterways. This will help ensure mechanical integrity of those pipelines is not compromised over time, and help avoid emergencies, like the one that occurred in Arvin. Public safety and protecting our natural environment should be the primary goal of all regulatory agencies in the state. These proposed regulations are a good step forward, and should be adopted.

Response: *Accepted. Thank you for your comment.*

COMMENTS IN OPPOSITION

SECTION 1760. DEFINITIONS

0001-1, 0002-4, 0005-6
The commenters suggest amending the definition of "active gas pipeline" in subsection (a) to exempt pipelines within a processing facility or subject to multiphase flow. The intent of AB 1420 is to regulate pipelines that transport single phase gas in sensitive areas between facilities and currently do not have specific regulatory requirements regarding the prevention of leaks. Multiphase pipelines are already covered under the rules imposed under AB 1960 and piping inside of processing facilities is already regulated by the California Occupational Safety and Health Administration (Cal/OSHA).

Response: *Rejected. Public Resources Code section 3270.5, subdivision (c)(1), defines "active gas pipeline" to mean "an in service gas pipeline regardless of diameter that is within the division's jurisdiction." Most oil production from a well contains multiple phases and both oil and gas well production must be processed to meet sales specifications for each commodity. Because of this, pipelines that carry gas may at times also carry liquids or solids. The definition "active gas pipeline" in section 1760, subdivision (a), further elaborates on the statutory definition to be clear that a pipeline that carries gas is still a gas pipeline, even if it carries some amount of liquids or solids. Excluding multiphase pipelines or pipelines within processing plants from the definition "active gas pipeline" would be inconsistent with the statutory definition and inconsistent with the purpose of this rulemaking, which is to ensure that pipelines that carry gas in sensitive areas are subject to regular inspection and testing.*

The California Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA), regulates pipelines from the perspective of employee health and safety. Cal/OSHA designates pipelines carrying natural gas as Class 2 pipelines. (Cal. Code of Regulations, title 8, § 6533, subd. (b)(3)(B)(2).) As such, these pipelines need only be inspected on a representative sampling, and "[t]he inspection interval shall not exceed 10 years or half the remaining life as determined from the corrosion rate calculation, whichever is less." (Cal. Code of Regulations, title 8, § 6533, subd. (b)(4)(B)(2).)

The Department's proposed regulations require a more stringent annual inspection regime for those active gas pipelines in sensitive areas. This better protects the public and the environment from the ill effects of leaking gases. Further, the proposed regulations do not prevent operators from complying with the requirements of Cal/OSHA's statutes and regulations.

0001-2, 0002-1, 0004-1, 0005-9
The commenters propose to amend the definition of "pipeline" in subsection (m) so that pipelines under the jurisdiction of the State Fire Marshal, as specified by the Elder Pipeline Safety Act of 1981 (commencing with § 51010 of the Government Code, and the regulations promulgated thereunder); the Pipeline and Hazardous Materials Safety Administration, per Title 49 Code of Federal Regulations Parts 192 and 195; or, under Cal/OSHA per CCR Title 8 chapter 14 article 9 subsection 6533 and Title 8 chapter 15 article 16 subsection 6845 are exempt from this definition. All pipelines under the jurisdiction of the federal and state agencies noted above are subject to strenuous mechanical integrity standards and are regularly audited for compliance.

Response: *Rejected. The California Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA), regulates pipelines from the perspective of employee health and safety. Cal/OSHA designates pipelines carrying natural gas as Class 2 pipelines. (Cal. Code of Regulations, title 8, § 6533, subd. (b)(3)(B)(2).) As such, these pipelines need only be inspected on a representative sampling, and "[t]he inspection interval shall not exceed 10 years or half the remaining life as determined from the corrosion rate calculation, whichever is less." (Cal. Code of Regulations, title 8, § 6533, subd. (b)(4)(B)(2).) The Department's proposed regulations require a more stringent annual inspection regime for those active gas pipelines in sensitive areas. This better protects the public and the environment from the ill effects of leaking gases. Further, the proposed regulations do not prevent operators from complying with the requirements of Cal/OSHA's statutes and regulations.*

The US Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) is the federal agency primarily responsible for pipeline regulation and safety. (49 USC, § 108, subd. (b), (f).) It adopts regulations that prescribe minimum pipeline safety standards for the pipeline transportation of natural gas and hazardous liquids. (See 49 CFR, §§ 190-192, 195.) PHMSA requires operators to conduct MIT testing in intervals of 7, 10, or 20 years, depending upon the specific yield strength of the pipeline. (See 49 CFR, § 192, App. E.) The two-year testing regime in the proposed regulations for active gas pipelines in sensitive areas is more stringent than the federal counterpart, and the proposed regulations do not prevent operators from complying with both sets of regulations.

The Office of the State Fire Marshal (SFM) has regulatory and enforcement authority over the safety of intrastate hazardous liquid pipelines. (Gov. Code, § 51010.) Through SFM's limited definition of "pipeline" and a Memorandum of Agreement with the Division, the Division, and not SFM, has authority over all pipelines "attendant to" oil and gas production, including pipelines within the administrative boundaries of oil and gas fields or that exist on the lease between the wellhead and custody transfer point. (See Gov. Code, § 51010.5, subd. (a).) The proposed regulations only affect Division-regulated gas pipelines; therefore, none of these regulations are inconsistent or incompatible with SFM regulations.

0002-5, 0002-6
The commenter recommends striking Section 1760, subdivision (t)(2). The commenter believes the existing language to be arbitrary and capricious; and Sections 1760, subdivisions (t)(1) and (3), provide protection. The commenter recommends revising the language in Section 1760, subdivision (t)(3), to include chronic _reportable_ leaks.

Response: *Rejected. The Division believes that this comment applies to Section 1760, subdivisions (r)(2) and (3), which are quoting the statutory language of Public Resources Code section 3270.5, subdivision (c)(2). The statutory language is quoted in the regulations to aid operators' understanding of the regulations by avoiding unnecessary cross-referencing between the Public Resources Code and the California Code of Regulations.*

SECTION 1774. PIPELINE CONSTRUCTION AND MAINTENANCE

0002-7
The commenter recommends Section 1774, subdivision (d), should only be considered for a Special Flood Hazard Area. Additionally, clarity is requested on what determines feasibility for racks and supports.

Response: *Rejected. Section 1774, subdivision (d), is a previously existing regulation that is not within the scope of this rulemaking.*

SECTION 1774.1. PIPELINE INSPECTION AND TESTING

0001-3, 0002-8, 0002-10, 0004-2, 0007-3
The commenter recommends modifying the language in Section 1774.1, subdivision (f), to further clarify that the regulations apply to pipelines that are 4 inches in diameter or less.

Response: *Rejected. Public Resources Code section 3270.5 requires the Division to review, evaluate, and update, where appropriate, its existing regulations concerning all active gas pipelines that are located in sensitive areas, less than four inches in diameter and 10 or more years old. However, consistent with the Division's broader mandate under to Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources, these regulations require operators to test and inspect all active gas pipelines in sensitive areas that are 10 or more years old, regardless of diameter.*

Although existing regulations already require operators to test all urban pipelines over four inches in diameter, larger gas pipelines in non-urban areas are not addressed by existing regulation. (See Cal. Code Regs., tit. 14, § 1774.1, subd. (e).) If the Division's new inspection and testing requirements for active gas pipelines in sensitive areas were to only apply to pipelines that are less than four inches in diameter, then larger pipelines in non-urban sensitive areas, such as communities like Arvin, would not be subject to the Division's testing and inspection requirements. These larger active gas pipelines pose at least the same, and arguably greater, risk to the public because they carry greater volumes of gas that can be released. Therefore, in order for the Division to address its broader mandate under Public Resources Code section 3106, it is necessary for these regulations to apply to apply to a broader set of pipelines than what is described in Public Resources Code section 3270.5, subdivision (a).

0001-12
The commenter recommends that all active gas pipelines be subject to leak surveys, using leak detection equipment at intervals not exceeding 7 ½ months, but at least twice a year.

0002-17
The commenter recommends that all active gas pipelines be subject to leak surveys, using leak detection equipment at intervals not exceeding 4 ½ months, but at least four times a year.

Response to 0001-12 and 0002-17: *Rejected. Although leak surveys are useful in detecting leaks in their infancy, they cannot be used as a method of preventative maintenance because they only detect hazardous chemicals that have already begun to contaminate the environment. In contrast, regular mechanical integrity testing can prevent leaks by demonstrating the wall thickness of the pipeline over time, giving the operator a chance to remediate any problems before a leak develops.*

0001-13, 0004-6
The proposed two-year MIT requirement is not based on any industry-accepted intervals or any intervals established by any federal or state government agencies.

Response: *Rejected. Existing regulations require mechanical integrity testing for oil gathering pipelines in environmentally sensitive areas and pipelines within urban areas every two years. (Cal. Code of Regs., tit. 14, § 1774.1, subd. (f).) The two-year testing frequency has proven to be effective under these long-standing requirements for ensuring the mechanical integrity of pipelines, and, responding to the mandate of Public Resources Code section 3270.5, subdivision (a), these same requirements are being applied to active gas pipelines ten or more years old in sensitive areas. However, operators may obtain approval from the Supervisor to test on an alternate frequency based on demonstrated wall thickness and remaining service life of the active gas pipeline over a period of at least two years. (Cal. Code of Regs., tit. 14, § 1774.1, subd. (f).)*

0001-14
This section should be modified to reflect the original intent of AB 1420 in detecting gas leaks and prevent them from impacting the public without undue costs, duplication, overlap or inconsistency with other federal and state regulations.

Response: *Public Resources Code section 3270.5, subdivision (a), requires the Division to review, evaluate, and update, where appropriate, its existing regulations concerning all active gas pipelines that are located in sensitive areas, less than four inches in diameter and 10 or more years old. Consistent with the Division's broader mandate under to Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources, these regulations require operators to test and inspect all active gas pipelines in sensitive areas that are 10 or more years old, regardless of diameter.*

The Division will work with operators, where appropriate, to accept the testing and inspection protocols that meet existing requirements imposed by other regulatory agencies. However, the proposed regulations do not prevent operators from complying with the requirements of other regulatory agencies.

0002-2, 0005-1, 0005-2
The commenter believes that the proposed regulations require unreasonable and, in some instances, dangerous testing requirements. Greater testing flexibility would allow operators to take into account field specific conditions. The commenter believes that this flexibility would come with the ability to use above-ground leak surveys, and also by deleting the provision that provides for the Supervisors' approval to use nondestructive testing to determine wall thickness. DOGGR has indicated that NDT will only be acceptable when the test can provide complete coverage of the pipeline, which is virtually impossible, requiring further problematic pressure testing. Also, the commenter offers that pneumatic testing utilizing methane is inherently risky and recognized as being the least preferable method for integrity tests. The commenter recommends leakage testing and alternative forms of testing be recognized as appropriate and applicable in the regulation.

Response: *Rejected. The Division believes that Section 1774.1 does provide the flexibility requested by the commenter. Subdivision (f) provides several methods for conducting mechanical integrity testing for pipelines, including the operator's ability to submit a testing method to the Supervisor for approval. The Division acknowledges that different testing methods may be appropriate in specific circumstances. For this reason, there is not a specific test that is required for all pipelines.*

0002-9
The commenter recommends modifying Section 1774.1, subdivision(d), by deleting a requirement that pipelines will not be returned to service unless the pressure testing has been successfully completed and the integrity of the pipeline has been verified to the Division's satisfaction. The commenter suggests adding a reference to regulations setting forth what a reportable quantity is before removing pipelines from service. Presently, there are no thresholds as to what is considered a reportable quantity.

Response: *Rejected. The current language of the regulation does not require Division verification before placing a pipeline back into service. Rather, the pipeline must successfully pass a pressure test, and those test results must be provided to the Division within seven days.*

While the Division has not specifically defined what constitutes a reportable quantity, other statutory and regulatory schemes do have definitions. If an operator discovers a pipeline within the Division's jurisdiction that has leaked a quantity that triggers reporting requirements to another agency, the leak must also be reported to the Division.

0004-3, 0005-6
The commenters suggest modifying Section 1774.1, subdivision (f), to include any gas lines, active or not, in a tank facility located within secondary containment and/or buffers, to be exempted from the mechanical integrity testing requirement. This section adds another layer of regulations to these pipelines and would force a Process Safety Management mechanical integrity program on these facilities. Section 1774.1, subdivision (a), already requires a visual inspection of above-ground lines that includes those located in sensitive areas which should be sufficient to identify active corrosion or leaks without the substantial cost of mechanical integrity testing.

Response: *Rejected. While visual inspection of above ground lines is valuable in detecting leaks after they have started, the goal of this rulemaking is the prevention of leaks in active gas pipelines in sensitive areas and mechanical integrity testing is essential to that goal. Section 1774.1, subdivision (b), allows operators to propose an alternate inspection frequency for approval by the Supervisor, and Section 1774.1, subdivision (f)(4), allows operators to propose alternate methods of mechanical integrity testing that ensure "mechanical integrity so as to protect life, health, property and natural resources." The Division will work with operators, where appropriate, to accept testing and inspection protocols, particularly those that meet existing requirements imposed by other regulatory agencies.*

0005-3, 0005-4, 0005-5
The proposed regulations exempt gas vapor recovery pipelines from mechanical integrity testing if they are equipped with safeguards such as oxygen detectors and are leak tested at least quarterly. The commenter recommends applying this same exemption to all gas pipelines, and suggests that the quarterly requirement be changed to annually. Regional air districts have long-established Clean Air Act (CAA) based leak detection and repair (LDAR) programs that impose annual inspection and repair requirements for vapor recovery systems designed to control the emission of volatile organic compounds (VOC) from a variety of oil and gas production equipment including central tank facilities,

gauging facilities, and production wells. The LDAR requirements are enforced via permits issued by the regional air districts. Additionally, the new Air Resources Board (ARB) Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, which become effective on January 1, 2018, will impose new LDAR requirements for equipment, including gas pipelines, not currently subject to CAA based LDAR and which will likely be administered by regional air districts. Revising subdivision (g) as proposed above serves to acknowledge the existence of the regulatory based LDAR framework operators already operate under and will serve to eliminate unnecessary regulatory duplication.

Response: *Partially Accepted and Partially Rejected. Based on the requirements of other regulatory bodies and comments received, the Division has modified Section 1774.1, subdivision (g), to exempt vapor recovery pipelines from mechanical integrity testing if they are equipped with certain safeguards and leak tested at least annually. This modification avoids unnecessary duplication of regulation. Moreover, the oxygen detectors on vapor recovery pipelines already provide a significant leak detection safeguard.*

The Division rejects the suggestion that all gas pipelines should be exempt from mechanical integrity testing. The Division has determined that mechanical integrity testing for all active gas pipelines in sensitive areas is the best method for meeting the statutory mandates of Public Resources Code sections 3106, 3270, and 3270.5.

0005-6
The proposed regulations are unclear as to how transmission lines within an administrative field boundary or gas gathering lines outside of an administrative field boundary will be handled. In actual field operations, numerous examples of both these conditions exist.

Response: *Rejected. This rulemaking only applies to active gas pipelines in sensitive areas that are ten or more years old and under the jurisdiction of the Division, i.e. within the administrative boundaries of an oil or gas field. This rulemaking does not apply to pipelines carrying liquids, and pipelines outside the administrative boundaries of an oil and gas field are not within the jurisdiction of the Division.*

0005-7
Piping inside of processing facilities is already regulated under Cal-OSHA as described in CCR Title 8 chapter 14 article 9 section 6533 and Title 8 chapter 15 article 16 section 6845. Therefore, the commenter recommends that additional requirements from AB 1420 should not be applied to "facility" piping. However, if the "facility" piping remains within the scope of AB 1420, the definition of a "facility" should clearly align with the existing definitions found within AB 1960 to ensure that "gas processing plants" are not included in the AB 1420 requirements.

Response: *Rejected. Public Resources Code section 3270.5, subdivisions (c)(1) and (c)(2), do not exempt piping within processing facilities; therefore, the regulations do not provide an exemption for them either.*

Cal/OSHA regulates pipelines from the perspective of employee health and safety. Cal/OSHA designates pipelines carrying natural gas as Class 2 pipelines. (Cal. Code of Regulations, title 8, § 6533, subd. (b)(3)(B)(2).) As such, these pipelines need only be inspected on a representative sampling, and "[t]he inspection interval shall not exceed 10 years or half the remaining life as determined from the corrosion rate calculation, whichever is less." (Cal. Code of Regulations, title 8, § 6533, subd. (b)(4)(B)(2).) The Department's proposed regulations require a more stringent annual inspection regime for those active *gas pipelines in sensitive areas. This better protects the public and the environment from the ill effects of leaking gases. Further, the proposed regulations do not prevent operators from complying with the requirements of Cal/OSHA's statutes and regulations.*

0005-8
The commenter suggests that the Division should modify section 1774.1, subdivision (b), related to the Supervisor's discretion to approve inspection frequency. The commenter recommends that the approval be based on demonstrated wall thickness and remaining service life over a period of at least two years. The commenter believes that this minor change will promote administrative efficiencies by allowing DOGGR and the operator to tie testing frequency requirements to the specific conditions of the line in question.

Response: *Rejected. As is, the language of Section 1774.1, subdivision (b), allows the Supervisor to approve an alternate inspection frequency based on many circumstances, including the demonstrated wall thickness and remaining service life over a period of at least two years.*

SECTION 1774.2. PIPELINE MANAGEMENT PLANS

0001-4
AB 1420 only prescribed data submission for "active gas pipelines" in "sensitive areas." The reference to data and mapping submissions in Section 1774.2, subdivision (a), adds confusion, and should be deleted.

Response: *Rejected. Although there was such a reference in a pre-rulemaking draft of these regulations, there is no reference to data and mapping submissions in Section 1774.2, subdivision (a), in these regulations.*

0001-5
The commenter suggests Section 1774.2, subdivision (b)(3), be amended so that AB 1420 modifications only address preventative maintenance practices associated with active gas pipelines in sensitive areas that are 4" or less in diameter. AB 1420 makes no references to valves, actuators, gauges, sensors or any other equipment outside of pipelines. Regulations regarding the maintenance practices of facilities and instrumentation have no effect on the detection of leaks from gas pipelines.

Response: *Rejected. Although Public Resources Code section 3270.5 does not specifically reference valves, actuators, gauges, sensors, or any other equipment outside of pipelines, each of these is important to the overall pipeline system and falls within the Division's jurisdiction to regulate. To meet the Division's mandate to protect damage to life, health, property, and natural resources under Public Resources Code section 3106, this section is necessary to ensure that operators are maintaining active gas pipelines according to best oil field practices using methods that the Division approves. Preventative maintenance protects public health and safety and the environment by identifying defects in pipelines before they result in spills, leaks, or blowouts.*

0001-6
The commenter suggests that requiring a list and maps of all pipelines that indicate which lines pass through sensitive areas, environmentally sensitive areas, urban areas, and designated waterways in an operator's pipeline management plan is outside the express scope of AB 1420 and drastically expands that scope.

Response: *Rejected. The Division has a broad mandate under Public Resources Code sections 3106 and 3270 to supervise the operation and maintenance of facilities attendant to oil and gas operations. Requiring a list and maps identifying pipelines and their locations is necessary to meet this statutory mandate. Further, operators are already required to have lists and maps of all pipelines in their Spill Contingency Plans. (Cal. Code of Regs, tit. 14, § 1722.9.)*

0004-4
The commenter recommends that Section 1774.2, subdivision (b)(4), be amended so that tank facilities designated as sensitive areas, environmentally sensitive areas, urban areas, and designated waterways are exempt from the map requirement. This map requirement would be cost prohibitive and disruptive to operations to employ survey firms with contractors on site to do survey work. If operators know the area to be a sensitive area, they should be able to provide a pipeline list, instead of a map.

Response: *Rejected. Maps of production facilities are already required as part of the operator's spill contingency plan. (Cal. Code of Regs., tit. 14, § 1722.9, subd. (f).) Plot plans, piping drawings, and facility maps may be submitted to meet the requirements.*

0004-5
Vapor recovery lines should be exempt from the mapping requirement in Section 1774.2, subdivision (b)(4), if they are equipped with the safeguards noted in Section 1774.1, subdivision (g). If these are exempt from the regulations, this needs to be clarified.

Response: *Rejected. The exemption provided for vapor recovery pipelines is specific to mechanical integrity testing. Mapping is required where the public or the environment may be at risk in sensitive areas.*

0005-10, 0008-1
Regarding data submissions generally, the commenter cites AB 1960 that states "The plan shall be provided to the Supervisor upon request." The commenter also offers the interpretation of that as meaning that "upon request" operators could either invite the Supervisor to see the database and the specific data requested or export a report to show the data for specific lines. The Pipeline Management Plan is often developed using Inspection Data Management software that can result in thousands of pages per plan. Therefore, it does not seem feasible to extract these entire databases; potentially thousands of pages, for submittal without putting a large burden on the operator as well as DOGGR to review and process such a request.

Response: *Rejected. Public Resources Code section 3270.5, subdivision (b), requires operators of active gas pipelines in sensitive areas to submit an up-to-date and accurate map identifying the location of their pipelines and other up-to-date locational information of the pipeline as determined and in a format specified by the Division as part of their Pipeline Management Plans. Based on this and the fact that operators are already required to have a Pipeline Management Plan, Section 1774.2, subdivision (a), now requires operators to submit their Pipeline Management Plans to the Division within one year of the effective date of this rulemaking. Operators may export reports from their data management software and/or propose alternative arrangements to provide this Pipeline Management Plan which may be more efficient for both the operator and the Division.*

<u>SECTION 1774.3. GAS PIPELINE DATA SUBMISSIONS</u>

0002-11, 0002-12, 0002-13, 0002-14, 0005-11
The commenters provide various suggestions for clarification, additions, and deletions for Section 1774.3. Some also expressed concern that mapping active gas pipelines is too time consuming and costly.

Response: *There is no Section 1774.3 in these regulations and gas pipeline mapping data submissions required under Public Resources Code section 3270.5, subdivision (b), are not addressed in this rulemaking. The Division has conducted some initial pre-rulemaking stakeholder engagement on this topic, but the Division has not initiated rulemaking to date.*

<u>ECONOMIC IMPACT ASSESSMENT</u>

0001-7, 0005-12
The commenters suggest amending the economic impact analysis to modify the presumption that there will be 80% pneumatic testing. The commenters believe assuming that 80% of the pipelines will be pneumatically tested is unreasonable, and the percentage should actually be closer to 100 percent hydrostatic. Pneumatic tests are inherently risky and are recognized as being the least preferable method for integrity testing in several codes and standards including the American Society for Mechanical Engineers B31.3, B31.4, B31.8 and Post Construction Code 2. Due to the safety risks and high level of management required to safely conduct such tests, pneumatic testing is unlikely to be utilized. The economic impact analysis should be modified to consider this presumption.

Response: *The Division's estimate of the percentage of operators choosing pneumatic testing is reasonable. The Division estimates that the majority of gas pipelines within a sensitive area to be less than 1,000 feet in length and most that pass through sensitive areas will be underground. The American Society of Engineers' ASME B31.8 code allows for pneumatic testing when the test pressure is below 30% of Specified Minimum Yield Strength (SMYS). Most sensitive area gas pipelines have lower operating pressures (below 30% SMYS) that will allow the use of pneumatic testing per these ASME guidelines. The Division estimates that most of these gas pipelines in sensitive areas will operate at or below 100 psi, are less than 1000 feet in length, are less than four inches in diameter, are underground which helps to dissipate stored energy during failure, and can have their physical condition assessed before choosing pneumatic pressure testing. For these reasons the Division believes that operators will choose pneumatic testing where they already have confidence in the condition of the pipeline and can perform the test safely. With a line assessed to be in good condition and meeting these other limits, it would be expected that the unlikely pipeline failure during pneumatic testing would be a limited failure where test medium gas is released, or blown down, over a measureable and significant time period. The American Society of Engineers allows this testing with significant margins of safety.*

0001-8, 0005-14
The commenter suggests DOGGR amend economic impact analysis to calculate the true cost impacts of testing. The costs proposed by DOGGR are skewed to a much lower value than reality. Specifically, DOGGR's cost estimates for pneumatic tests are approximately 50% lower than the cost for an equivalent hydrostatic test. As noted above, the analysis should be based on the assumption that

hydrostatic tests, not pneumatic tests, will be the primary testing method. When feasibility and safety considerations are factored in, DOGGR should estimate that virtually zero pneumatic tests will be performed. Further, it should be noted that DOGGR's analysis estimates a substantially lower cost to hydrostatically test buried pipelines than to hydrostatically test aboveground pipelines. WSPA does not concur with the assumption that the cost on a buried line would be half the cost of an aboveground line. If a round number of $15,000 per pressure test is used for all pipelines that DOGGR is estimating will be impacted by AB 1420 requirements, the new cost impact would more accurately be $69,135,000 for the first year. The values used by DOGGR for the hydrostatic testing costs appear to be very low. Other costs must be included such as water sourcing, equipment rentals for water storage, third-party testing companies, and disposal of the hydro testing water, so a higher average value should be applied to calculate the true cost impacts.

Response: *In developing the cost estimates, the Division consulted with experienced professionals, including contractors that conduct testing. Most sensitive area gas pipelines have lower operating pressures (below 30% SMYS) that will allow the use of pneumatic testing per ASME guidelines. The DOGGR estimate of the percentage of operators choosing pneumatic testing is reasonable. The Division used very conservative estimates and assumptions about both the number of pipelines covered by the regulations, as well as the testing that operators are already conducting. The Division concedes that the comment about the relative cost of a hydrostatic test for a buried pipeline may have merit. Even if the cost estimate of hydrostatic testing for buried pipelines is increased to that of the aboveground pipelines, the total cost estimate (ref. ISOR, App. A) for testing 802 buried pipelines increases from $3,321,082 to $6,314,146. This adjustment puts total testing cost estimate to be $17,621,696, which is still well below the SRIA cost threshold. Based on the number of lines reported to date, it appears that 802 buried lines is also conservatively high. The Department is reasonably confident that the existing cost estimates more than cover the potential costs imposed by these regulations.*

0001-9
The commenter suggests that the Division modify the economic impact analysis to include all the lines in the scope of the regulation as written or the regulation needs to be modified to reflect the actual scope. The analysis estimates a cost using a total number of pipelines (4,609) that does not include stated testing requirements for "facility" piping. As written, the regulation does not exempt such piping and the number of lines would increase by several times.

Response: *In developing the cost estimates, the Division used very conservative estimates and assumptions about the number of pipelines covered by the regulations. The pipelines within a production facility are often above ground, already have testing required by Cal/OSHA as well as other safeguards such as fugitive emission leak detection, and may propose alternative testing based on the testing regimes already in use. Since the operator is already bearing the cost of existing testing and since this existing testing may be proposed as an alternative means of meeting the Division's testing requirements, new or additional costs should be limited.*

0001-10, 0005-16
The commenters suggest DOGGR modify economic impact analysis to include additional costs to develop detailed information of the piping system contained within a facility; or modify regulation to reflect the actual scope. The commenters believe DOGGR has ignored the economic infeasibility of operators having to develop three-dimensional models or multiple layers of two-dimensional images to represent each individual piping system contained within a "facility."

Response: *Operators are already required to have this basic design information for their pipelines or piping systems within a production facility per Cal/OSHA. More highly detailed two and three dimensional models are not intended or required under these regulations. Existing plot plans, piping diagrams, or process flow diagrams that are part of the facility design documentation may be used to identify locations of pipelines with respect to sensitive locations. The specific requirements for gas pipeline mapping data submissions under Public Resources Code section 3270.5, subdivision (b), are not addressed in this rulemaking.*

0001-11, 0002-3, 0005-15
The commenters suggest DOGGR include the additional costs impacts of production curtailments to the operator to reflect the real costs of the regulation's current testing requirements. The commenters believe DOGGR has ignored the cost from loss of production if a pipeline or facility is shutdown to conduct the mechanical integrity testing on a two-year frequency, potentially for multiple days. Production curtailments without warranted mechanical integrity risk mitigation will cause an economic hardship on operators.

Response: *The Division's economic analysis is a static estimate of the costs of testing. However, the Division used conservative estimates with the knowledge that it may encompass some indirect costs that go beyond simply obtaining equipment and conducting the test. The Division disagrees that the testing is unwarranted. The affected active gas pipelines are primarily located in areas of human habitation. Biennial mechanical integrity testing helps to prevent pipeline leaks by detecting defects before they result in leaks. Given the location of the pipelines, this is necessary to protect the public and environment. Moreover, the operator may obtain the approval of the Supervisor to conduct mechanical integrity testing on an alternate frequency based on the demonstrated thickness and remaining service life of the pipeline over a period of at least two years. (Cal. Code of Regs., tit. 14, § 1774.1, subd. (f).)*

0002-15, 0005-17, 0007-1
The commenters recommend DOGGR revisit its economic impact analysis and complete a Standardized Regulatory Impact Assessment (SRIA) on the regulations. The estimated costs associated with these regulations are expected to exceed the annual $50 million for California operators; requiring a SRIA, after accounting for possible increases in costs for testing and lost production. Also, DOGGR must understand that there is a cumulative economic impact associated with other oil and gas related rulemakings that are currently moving forward by DOGGR, in addition to regulations from other state agencies and Local governments that are already in place.

Response: *The Division disagrees that this rulemaking requires a Standardized Regulatory Impact Assessment. The Division's Economic Impact Analysis estimated that 4,609 active gas pipelines would require testing under the proposed regulations. In developing this estimate, the Division deliberately used conservative assumptions concerning the number of locations that fall within the definition of a sensitive area, but not an urban area, and, therefore, the number of pipelines that will now need to be inspected and tested under these regulations.*

Further, although the regulations provide the flexibility for alternate testing and inspection frequencies, the Division's economic analysis also assumes that all of the testing costs will be new and incurred every two years and all of the inspection costs will be incurred every year. The Division anticipates accepting alternative testing types, as well as alternate testing and inspection schedules. Based on this, the

Division believes that its cost estimates are actually substantially overestimated. Still, the estimated impacts are well below the threshold for requiring a Standardized Regulatory Impact Assessment.

0005-13
The commenter recommends that the economic impact analysis be re-analyzed to modify the presumption that methane could be used in pneumatic testing. The potential for the use of methane by operators raises the risk and would not be allowable per DOT/PHMSA codes for jurisdictional pipelines; it would trigger a "safety-related condition" as the pipeline would be subjected to >110% of the MAOP while still containing the flammable gas.

Response: *The Division's Economic Impact Analysis does not presume that methane would be used, only that it is an option when conducting pneumatic testing. The Economic Impact Analysis also identifies air and nitrogen as other general mediums for conducting a pneumatic test. Further, the Department of Transportation, Pipeline and Hazardous Materials Safety Administration allows for some pneumatic testing with lower maximum hoop stress limitations. (49 C.F.R. 192.503, subd. (c).) Section 1774.1, subdivision (f), gives the operator the flexibility to identify effective mechanical integrity testing methods based on the pipeline type and use, and the assumptions in the Economic Impact Analysis reflect that.*

Other Comments

0006-1
The commenter requests the term "mechanical integrity testing" be defined as part of the definitions. The term "mechanical integrity testing" is used throughout the AB 1420 Proposed Regulations as an integral part of AB 1420, but the commenter was unable to locate where it is defined in DOGGR regulations.

Response: *Rejected. Mechanical integrity testing was required for certain types of pipelines prior to this rulemaking, the term is commonly understood by the regulated public, and the parameters of an acceptable mechanical integrity testing regime are set forth in the regulations.*

0007-2
The commenter is concerned with the format of the public comment hearing because he is not able to have a back-and-forth dialogue.

Response: *A public comment hearing is held for the sole reason of receiving comments from the public concerning the regulations proposed by the State agency. The Division held pre-rulemaking workshops in the summer and fall in which participation from attendees was actively encouraged, including question and answer sessions. There was significant turnout and many attendees continued dialogue with Division staff on the development of these regulations.*