INITIAL STATEMENT OF REASONS (ISOR)

CALIFORNIA CODE OF REGULATIONS
TITLE 19, DIVISION 1, CHAPTER 14,
ARTICLE 8. IN-LINE INSPECTION REQUIREMENTS

EXISTING LAW

The California Department of Forestry and Fire Protection's – Office of the State Fire Marshal (OSFM), Pipeline Safety Division (PSD) exercises exclusive safety, regulatory, and enforcement authority over approximately 5,300 miles of intrastate hazardous liquid pipelines. The OSFM consists of engineers, analytical staff, and clerical support located in Northern, Central, and Southern California that inspect pipeline operators to ensure compliance with federal and state pipeline safety laws and regulations. The OSFM is also responsible for the investigation of pipeline ruptures, fires, and accidents for cause and determination of probable violations of pipeline safety laws and regulations.

The OSFM regulates the safety of intrastate hazardous liquid pipelines through certification from the United States Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA). The current PHMSA certification requires the OSFM to conduct six (6) different types of inspections on each intrastate hazardous liquid pipeline operator, and two (2) different types of inspections on each intrastate hazardous liquid pipeline once every five (5) years, among other regulatory requirements. In broad terms, PHMSA requirements are contained in federal statute and regulations and set the minimum regulatory requirements on hazardous liquid pipeline operators. Any state, including California, that maintains a certification from PHMSA may impose additional requirements on hazardous liquid pipeline operators. The PHMSA requirements represent minimum requirements that California can build upon. For example, the OSFM recently adopted regulations, as directed by Senate Bill 295 (Jackson, 2015), to conduct additional California specific inspections of pipelines and pipeline operators on a more frequent annualized basis. Existing state and federal laws focus on protection of the health and safety of individuals and the environment. Because there are no current requirements for in-line inspection tools, the proposed regulations seek to further improve the protection of the public, property, and the environment by closing this regulatory gap. The proposed regulations ensure that operators are strengthening the evaluation and remediation of their pipeline integrity threats and are taking action to mitigate the adverse effects of pipeline failures.

SPECIFIC PURPOSE AND RATIONALE

1. Problem being addressed:

The proposed regulations will reduce the likelihood of a release of hazardous liquid and avoid the resultant economic impacts to the operator, residents, and the State by requiring the use of reliable data sources and aligning key risk factors and parameters in regards of integrity of the pipeline.

A deadly pipeline rupture and fire that occurred in San Bernardino, California in 1988 brought to light the need for operators to address potential pipeline failure causes. As a result, Assembly Bill 385 (Assembly Member Dave Elder, 1989) and Senate Bill 268 (Senator Herschel Rosenthal, 1989) introduced two (2) bills that directed the OSFM to conduct studies of hazardous liquid pipeline failures based on various risk factors. The Bills were codified in the Elder Pipeline Safety Act of 1981 in Sections 51013 and 51013.5 of the Government Code. The relevant sections are as follows:

- Section 51013(b) states, "Any new pipeline on which construction begins after January 1, 1990, shall be designed to accommodate the passage of instrumented internal inspection devices, and shall have leak mitigation and emergency response plans and equipment as the State Fire Marshal may require. Any repairs to existing pipelines which can accommodate instrumented internal inspection devices shall be done in a manner not to interfere with the passage of these devices."

- Section 51013(d) states, "For pipelines which cannot accommodate internal inspection devices, replacements of portions of the pipe shall be done in a manner consistent, to the extent practicable, with the eventual accommodation of instrumented internal inspection devices."

- Section 51013.5(g) states, "The State Fire Marshal shall study indicators and precursors of serious pipeline accidents, and, in consultation with the Pipeline Safety Advisory Committee, shall develop criteria for identifying which hazardous liquid pipelines pose the greatest risk to people and the environment due to the likelihood of, and likely seriousness of, an accident due to corrosion or defect. The study shall give due consideration to research done by the industry, the Federal government, academia, and to any other information which the State Fire Marshal shall deem relevant, including, but not limited to, recent leak history, pipeline location, and materials transported. Beginning January 1, 1992, using the criteria identified in that study, the State Fire Marshal shall maintain a list of higher risk pipelines, which exceed a standard of risk to be determined by the State Fire Marshal, and which shall be tested as required in subdivisions (c) and (d) as long as they remain on the list. By January 1, 1992, after public hearings, the State Fire Marshal shall adopt regulations to implement this subdivision."

- 51013.5(h) states, "In addition to the requirements of subdivisions (a) to (e), inclusive, the State Fire Marshal may require any pipeline subject to this chapter to be subjected to a pressure test, or any other test or inspection, at any time, in the interest of public safety."

- 51013.5(j) states, "The State Fire Marshal shall adopt regulations before January 1, 1992, to establish what the State Fire Marshal deems to be an appropriate frequency for tests and inspections, including instrumented internal inspections, which, when permitted as a substitute for tests required under subdivisions (b), (c), and (d), do not damage pipelines or require them to be shut down for the testing period. That testing shall in no event be less frequent than is required by subdivisions (b), (c), and (d). Each time one of these tests is required on a pipeline, it shall be approved on the same individual basis as under subdivision (i). If it is not approved, a hydrostatic test shall be carried out at the time the alternative test would have been carried out, and subsequent tests shall be carried out in accordance with the time intervals prescribed by subdivision (b), (c), or (d), as applicable."

These statutes direct the OSFM to adopt regulations for intrastate hazardous liquid pipelines addressing construction, design, inspection, and testing of new and existing pipelines.

2. Anticipated benefits from this regulatory action:
The proposed regulations are designed to gather timely information by using reliable data sources and aligning key risk factors and parameters in regards of integrity of the pipeline. Operators will be able to gather sufficient information on the pipeline and integrate information about their pipelines to identify the threats the pipeline is facing. This will allow operators to determine the best means of addressing the risks facing their pipelines. Operators will be able to prevent or reduce unexpected leaks or ruptures from pipelines, thereby protecting the public, property, environment, and wildlife from the resultant harm of a hazardous liquid spill.

3. Factual Basis/Rationale:
The goals of the in-line inspection requirements regulations are (1) to meet the statutory mandates; (2) to reduce the likelihood of failures; (3) to improve protection of the public, property, and environment. To achieve these goals, the legislature directed the OSFM to adopt regulations that would require hazardous liquid pipeline operators to test and inspect, including instrumented internal inspections of the pipelines, as appropriate for the threat being assessed. These assessments will provide essential information to pipeline operators about the condition of their pipelines, including but not limited to, the existence of internal and external corrosion, stress corrosion cracking, deformation anomalies, and manufacturing defects. Specific components of the proposed in-line inspection requirements regulations require the pipeline operator to identify and mitigate the risks to their pipeline systems, such as: determine likely threats to the pipeline, evaluate and assess the physical integrity of the pipeline, and repair and remediate any pipeline defects found in accordance with the standards. Without regulatory action by the OSFM, statutorily defined terms and requirements contained in the legislation would fail to completely meet the goals of in-line inspection requirements regulations based on current engineering principals and research. Pursuant to Government Code, Section

51013.5, the OSFM was directed to develop regulations for testing hazardous liquid pipelines using internal inspection devices. With the proposed regulations, the OSFM and industry can adequately and effectively carry out the legislative mandates of in-line inspection regulations.

SUMMARY

The proposed in-line inspection (ILI) regulations incorporate several recommendations from the National Transportation Safety Board (NTSB) and statutory mandates to OSFM concerning areas where the risk of a pipeline release could have significant impacts to the public, property, and environment. The proposed ILI regulations specifies the use of an ILI to assess, evaluate, repair, and validate the integrity of pipelines through a comprehensive analysis. The OSFM is proposing regulations to require all hazardous liquid pipelines be made capable of accommodating ILI tools within 5 years of the effective date of the regulations, unless granted an exemption, based on the construction and operation of the pipeline that will not allow for the accommodation of an ILI.

ILI tools can provide a relatively complete examination of the entire length of a pipeline, including information about threats that other assessment methods cannot always identify. ILI tools also provide superior information about flaws that are not yet a threat to pipeline integrity, but that could become so in the future. ILI tools allow these conditions to be monitored over consecutive inspections and remediated before a pipeline failure occurs. Hydrostatic pressure testing, another well-recognized method, reveals flaws (such as wall loss and cracking flaws) that cause pipe failures at pressures that exceed actual operating conditions, but only allows operators to determine whether a pipe will fail or can withstand specified pressure, and does not provide information about the existence of anomalies that could deteriorate over time between tests.

Similarly, external corrosion direct assessment (ECDA) is a form of direct assessment that can identify instances where coating damage or ineffective coatings may be affecting pipeline integrity, but operators must perform additional activities, including follow-up excavations and direct examinations, to verify the extent of that threat. ECDA also does not provide information about the internal condition of a pipe to the extent an ILI tool would. The proposed regulation requires an operator to develop and follow a robust ILI program that provides for continually assessing the integrity of all pipeline segments. Thus, hazardous liquid operators must evaluate the entire range of threats to each pipeline segment's integrity by analyzing all the information about the pipeline segment. This regulation specifies an operator to take prompt action to address the integrity issues raised by assessment and analysis. This means an operator must evaluate all defects and repair those that could reduce pipeline integrity. An operator must develop a remediation schedule that prioritizes the defects for evaluation and repair, including the time frame for promptly reviewing and analyzing the integrity assessment results and completing the repairs.

TECHNICAL, THEORETICAL, AND/OR EMPIRICAL STUDY OR REPORT

The OSFM consulted with and received input from the State Fire Marshal's Pipeline Safety Advisory Committee (PSAC). The PSAC consists of representatives from the pipeline industry, the fire service, local agencies, and the public. In addition to the PSAC member input, the OSFM relied on the following technical, theoretical, and/or empirical studies, and reports when developing the proposed regulations:

- California State Fire Marshal, “Hazardous Liquid Pipeline Risk Assessment” April 1993
- American Petroleum Institute Recommended Practice 1160, “Managing System Integrity for Hazardous Liquid Pipelines” (Second Edition, September 2013)
- American Petroleum Institute 579, “Fitness-For-Service" (Second Edition, June 2016)
- American Petroleum Institute Recommended Practice 1176, “Recommended Practice for Assessment and Management of Cracking in Pipelines” (First Edition, July 2016)
- The American Society of Mechanical Engineers Code for Pressure Piping B31.4, “Pipeline Transportation Systems for Liquids and Hydrocarbons and Other Liquids” October 20, 2006
- The American Society of Mechanical Engineers Code for Pressure Piping, B31.8S-2004 (Managing System Integrity of Gas Pipelines)
- NACE International SP0102-2010, “Standard Practice, In-Line Inspection of Pipelines” revised March 13, 2010
- NACE International Publication 10A392, “Effectiveness of Cathodic Protection on Thermally Insulated Underground Metallic Structures” September 2006
- U.S. Department of Transportation – Research and Special Programs Administration Office of Pipeline Safety (Prepared by Kiefner and Associated, Inc. And CorrMet Engineering Services, PC). Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, February 2004
- National Transportation Safety Board, “Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release in Marshall, Michigan” July 25, 2010 [NTSB/PAR-12-01]
- National Transportation Safety Board, “Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire in San Bruno, California” September 9, 2010 [NTSB/PAR-11/01]
- Pipeline and Hazardous Materials Safety Administration Special Permit, “HECO’s Waiau Pipeline Proposes Waiving Compliance with 195.571 and 195.573” October 2, 2018
- Pipeline and Hazardous Materials Safety Administration Advisory Bulletin, “Ineffective Protection, Detection, and Mitigation of Corrosion Resulting From Insulated Coatings on Buried Pipelines” [Docket No. PHMSA-2016-0071]

- United States of America and the People of the State of California Consent Decree, “Limited Effectiveness of Cathodic Protection on Lines 901, 903, and 2000” March 13, 2020

NECESSITY

Introduction

California relies heavily on pipelines to transport hazardous liquids, such as crude oil and refined petroleum products from production areas to refineries and other downstream facilities such as airports. Pipeline failures can result in distribution issues at the regional, State, and interstate level. The State has experienced multiple significant pipeline accidents following the codification of Government Code §§ 51013, 51013.5, that stems from a major accident in San Bruno in 1989. Recent accidents include 63,000 gallons of gasoline released in the Walnut Creek waterway in 2020, and the Santa Barbara oil pipeline rupture that spilled over 100,000 thousand gallons of crude oil into the ocean in 2015. These accidents caused significant environmental and economic impacts and further highlight the need for California to draft regulations relating to hazardous liquid pipeline safety, particularly pipeline integrity assessments and repairs. The legislature adopted Government Code, §§ 51013.1 and 51015.1 in the aftermath of the Refugio accident. Shortly thereafter, the OSFM adopted regulations in Title 19, Code of Regulations, §§ 2020 and 2100 et seq.

NTSB Recommendations

The NTSB has conducted investigations into pipeline accidents throughout the United States including California and has made several recommendations for improving pipeline safety. For example, the NTSB's investigation into the San Bruno explosion found that existing pipelines should be retrofitted to accommodate ILI tools to facilitate inspection and maintenance. This recommendation was based on pipelines that cannot accommodate ILI tools, such as the one that ruptured in San Bruno, are difficult to assess the integrity of pipeline and may be more prone to failure.

The NTSB's investigation into the 2010 crude oil pipeline rupture near Marshall, Michigan also identified the need to develop criteria for determining when a probable crack defect in a pipeline must be field evaluated and remediated, and the need for time limits to be established for completing those mitigative actions. In addition, the NTSB recommended developing acceptable integrity assessment methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable.

OSFM Study Recommendations

In 1993 the Legislature directed the OSFM undertake a study evaluating ways to reduce external corrosion, which is a major threat to pipeline integrity. The study recommended evaluating the effectiveness of coatings, cathodic protection (CP) systems, and in-line inspection tools. The study also recommended finding ways to reduce external corrosion leaks through remediations such as pipeline replacements or recoating.

PHMSA Recommendations
PHMSA has also made recommendations for improving pipeline safety. In its Advisory Bulletin ADB-2016-04, following the release of PHMSA's Failure Accident Report for the crude oil spill in 2015 near Santa Barbara, PHMSA identified the need for the following actions relating to buried and insulated pipelines: (1) more frequent reassessments; (2) usage of appropriate integrity assessment tools for all threats including stress corrosion cracking (SCC); (3) more stringent repair criteria targeted at corrosion under insulation (CUI) or corrosion under disbonded coatings; and (4) coordination of data from the appropriate ILI technologies to determine corrosion and/or crack growth rate (CGR) with run comparisons.

PHSMA regulations already require new and replaced pipelines to accommodate ILI tools, and many of the pipelines covered by the federal rule will need to be replaced and accommodate ILI tools before the end of a 20-year implementation period.

California Statutes
California law grants OSFM the authority to regulate hazardous liquid pipelines. California statutes give the State authority to draft regulations relating to hazardous liquid pipeline safety. Specifically, Government Code §§ 51013.5(g), 51013.5(j), and 51015.5(c) state that the OSFM shall adopt rules and regulations relating to integrity assessments and pipeline repairs.

Conclusion
California has experienced several hazardous liquid pipeline accidents over the years, and it is imperative that the State takes steps to lower the risks associated with pipeline failure. The NTSB, PHMSA, and OSFM have all made recommendations for improving pipeline integrity assessments and repairs, and California law grants the authority for the OSFM to not only regulate intrastate hazardous liquid pipelines but also adopt regulations pertaining to pipeline safety. By incorporating these recommendations into regulations and enforcing them, California can help ensure the safety of its citizens and the environment. Thus, this regulation will address several statutory mandates, NTSB recommendations, PHMSA advisory bulletins, and pipeline safety and environmental issues where the risk of a pipeline spill could have significant impact.

CONSIDERATION OF REASONABLE ALTERNATIVES TO THE REGULATION AND THE STATE FIRE MARSHAL'S REASONS FOR REJECTING THOSE ALTERNATIVES

The OSFM thoroughly reviewed the proposed regulatory action, including both positive and negative impacts that could be placed on the regulated community. The OSFM has determined that no reasonable alternative it considered to the regulations or that has otherwise been identified and brought to its attention would be more effective in carrying out the purpose for which the action is proposed, nor would they be as effective. They also would not be less burdensome to the affected persons or businesses than the proposed action, nor would they be more cost effective to affected private persons and equally effective in implementing the statutory policy or other provisions of law. The alternative of no regulatory action would not be in the best interest of the public.

REASONABLE ALTERNATIVES – SMALL BUSINESS

The proposed regulations have no substantial effect to small business. The OSFM has made the initial determination that these proposed regulations will have no "substantial" effect to small businesses and the OSFM has identified no alternative that would lessen adverse impact, if any, on small business and still allow the OSFM to effectively enforce the regulations. California Government Code § 11342.610 excludes "a petroleum producer, a natural gas producer, a refiner, or a pipeline" from evaluation consideration as a small business.

ALTERNATIVES CONSIDERED

Though the OSFM determined that there are no reasonable alternatives to the approach proposed in the regulations, our office evaluated several alternatives detailed below.

Alternative #1 – Wait for federal regulations to come into effect

The federal regulatory oversight agency (PHMSA) has adopted regulations requiring all pipelines that could impact a High Consequence Area to be able to facilitate ILI tools within the next 10 -20 years. All pipelines in California that are not capable of hosting an ILI inspection tool would need to be retrofitted to accommodate an ILI tool. In PHMSA's own regulatory analysis they estimated that "Costs (to retrofit pipes to accommodate ILI) and benefits (from avoided damages) would accrue only to the extent that existing practices deviate from industry standards; PHMSA expects costs and benefits will be minimal due to baseline prevalence of ILI-capable pipelines in all areas." The costs were so minimal that no dollar value was provided in the analysis. This information correlates to the data our office obtained while researching the proposed regulations. Essentially, the difference between continuing business as usual and implementing ILI launchers and inspections is nearly equal to the present costs associated with hydrotesting.

Under this alternative, the OSFM would not promulgate regulations and simply wait for PHMSA's regulations to become fully implemented. As such, the OSFM concluded that there would be no impact to pipeline operators in California. The OSFM ultimately rejected this approach because waiting another 10-20 years for pipelines in California to facilitate ILI inspection tools presents a risk that can and should be avoided. The proposed rule is designed to mitigate or prevent hazardous liquid pipeline accidents, reduce accident damages, cleanup and response costs, property damage, product loss, and environmental impacts. The proposed regulations will enhance an operator's ability to identify and address risks prior to spills.

Alternative #2 – Maintain a 10-year inspection interval
Under this alternative, the OSFM considered the assessment interval of pipelines to be set to at least every 10 years, as opposed to no longer than once every 5 years as proposed by the OSFM. The OSFM also considered allowing operators the choice of evaluation tools for all pipe regardless of design or known manufacturing defects.

The less frequent ILI testing regime would result in cost savings to operators, essentially leaving the costs for compliance equal to existing law or even lowering operational costs not associated with spills. However, this regime would provide no additional benefit through reduced spills and associated cleanup costs, among others. This alternative was ultimately rejected because the testing frequency failed to properly capture pipelines based on identified risks present on a pipeline. For example, if operators have identified a pipeline segment with identified or probable risks or threats related to corrosion and deformation anomalies, including dents, gouges, or grooves, then the operator must assess that segment with a tool capable of detecting those anomalies. Similarly, operators should assess pipeline segments with an identified or probable risk or threat related to cracks using a tool capable of detecting crack anomalies. Essentially, operators should always be selecting an appropriate assessment tool based on the pertinent threats to a given pipeline segment identified by an operator's risk assessment. An operator's risk assessment should always be driving its integrity assessments and the integrity management program. An operator cannot properly maintain its pipeline if it does not know what threats the pipeline is susceptible to and which tools the pipeline operator should be selecting to assess those threats. These threats can include, but are not limited to, pipe that may have manufacturing defects or have otherwise experienced in-service accidents.

This alternative would allow operators to continue evaluating pipelines utilizing hydrostatic testing, which imparts much less data to determine risks on a pipeline, let alone project future repair conditions. Our office and pipeline operators have expressed interest in improving ILI methods as an alternative to hydrostatic testing for better risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs and occasional disruptions in service, whereas ILI testing can obtain data that is not otherwise obtainable via other assessment methods, such as pipe wall loss, dents, and cracking. Given the benefits of ILI tools over traditional testing methods, the proposed alternative would not meet or address the concerns evident in existing testing methods. However, to implement data gathered by ILI tools a time frame for evaluation of 5 years, rather than 10 years, allows for better understanding of anomalies and defects on a pipeline prior to potential failures. The 5 year evaluation time frame also corresponds to State law requirements where pipelines must be evaluated at least once every 5 years.

Alternative analysis conclusion
The proposed regulation will provide benefit by avoiding damages from pipeline failures through earlier detection and remediation. The enhanced data provided by ILI tools further allows operators and OSFM to better evaluate risks, avoid pipeline failure, and mitigate costs associated with cleanup following a release.

EVIDENCE SUPPORTING FINDING OF NO SIGNIFICANT ADVERSE ECONOMIC IMPACT ON ANY BUSINESS

The OSFM has initially determined that the proposed regulations will not have a significant adverse economic impact on business. Review of facts, documents, testimony, and other evidence indicates that the proposed regulation will likely have an overall economic benefit on business within the State of California. While an economic impact is anticipated, both the regulated industry and other businesses stand to benefit significantly from the proposed regulations through increased sales, revenue, and jobs that would otherwise be lost in the event of an oil spill. Additional benefit will be realized through costs avoided in reduced spills, thereby offsetting adverse economic impact.

ECONOMIC IMPACT ANALYSIS AND ASSESSMENT

The proposed regulations will have a positive impact on the ability of the OSFM to carry out its inspection and enforcement authority. It will ensure consistency through the State in terms of compliance with federal and state laws, enhance public safety, protect California’s vital natural resources and wildlife, and reduce the risk of future pipeline accidents.

The Creation or Elimination of Jobs within the State of California
The OSFM has determined that this regulatory proposal will not have an impact on the creation or elimination of jobs. During the crafting of the regulations, stakeholder impacts were considered. Discussions with industry involved in ILI construction and evaluation indicate an increase in activity but do not anticipate hiring more staff to manage an anticipated increased workload. The conclusion reached is that the regulations do not impact how current operations are conducted and therefore will not impact the creation or elimination of jobs.

The Creation of New Businesses or the Elimination of Existing Businesses within the State of California
The OSFM has determined that this regulatory proposal will not have an impact on the creation of new businesses or the elimination of existing businesses. The regulations serve to improve the pipeline inspections which have no negative effect on the business environment.

The Expansion of Businesses Currently Doing Business within the State of California
The OSFM has determined that this regulatory proposal will not have a significant impact and will not limit or discourage the expansion of existing businesses within the State of California.

Benefits of the Regulations to the Health and Welfare of California Residents, Worker Safety, and the State's Environment
This regulatory proposal provides a direct benefit to the protection of the environment, public health and safety of Californians. The regulations also would ensure consistency throughout the State in terms of pipeline technologies and inspection intervals to protect California's vital natural resources and wildlife, and reduce the risk of future pipeline accidents.

LOCAL MANDATE DETERMINATION
The proposed regulation does not impose any mandate on local agencies or school districts.

COORDINATION WITH FEDERAL LAW
Pursuant to the Hazardous Liquid Pipeline Safety Act, the OSFM exercises exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines through certification granted by the United States Secretary of Transportation, California Government Code § 51010, and Title 49 of the United States Code (49 USC) §§ 60104, 60105. The OSFM currently holds certification from the Secretary of Transportation, and pursuant to that certification, may adopt additional or more stringent safety standards for intrastate pipeline facilities and intrastate pipeline transportation if the standards are compatible with the minimum standards prescribed under 49 USC §§ 60101 et seq. and associated regulations found in Parts 190 – 199 of the Code of Federal Regulations. The OSFM determined that the proposed regulatory action neither conflicts with nor duplicates any federal statute, regulation, or law applicable to intrastate hazardous liquid pipelines and is consistent with the minimum standards required to maintain certification.

INCORPORATED BY REFERENCE DOCUMENTS:

1. American Petroleum Institute Recommended Practice 1160, "Managing System Integrity for Hazardous Liquid Pipelines" (Second Edition, September 2013)
The American Petroleum Institute (API) is recognized across the pipeline industry and state and federal regulatory agencies as containing an extensive body of knowledge and expertise relating to pipeline operations. API standards are incorporated in regulatory standards by other state regulators, and PHMSA, the federal counterpart to the OSFM. This existing national industry standard provides guidance and

recommended practices to pipeline operators of hazardous liquid pipeline systems when developing a pipeline integrity management program. Incorporating this standard ensures that the remaining lives of anomalies in the pipeline are calculated so that reassessment can be carried out to reevaluate and remediate the anomalies. And it helps operators prioritize the pipeline segments for assessment by risk, assess the segments for anomalies that could threaten integrity, and mitigate the risk by removing and repairing injurious defects.

The OSFM determined that API RP 1160 2nd edition must be referenced in lieu of the 3rd edition. The proposed ILI regulations references API RP 1160 to determine reassessment intervals and calculate burst pressure for anomalies such as metal loss and cracks (see **§ 2157. Assessment Intervals** and **§ 2158. Required Validation, Field Evaluation and Repairs**). In Section 9 of API RP 1160 2nd edition, the standard explains in detail how to calculate the non-linear growth rate of anomalies such as fatigue cracks by using the “Paris Law” relationship. However, in Section 10 of API RP 1160 3rd edition, the standard simply references another standard, API RP 1176 (*Recommended Practice for Assessment and Management of Cracking in Pipelines*), to calculate the nonlinear growth rate of anomalies such as fatigue cracks. The risk of specifying the 3rd edition of API RP 1160 in our draft ILI regulation is that it simply references another Recommended Practice (i.e. API RP 1176) when determining non-linear growth rate of fatigue cracks. API RP 1176 does not utilize mandatory languages such as “must” or “shall”; rather, it uses optional languages such as “should”, “may”, or “recommended” which makes it incredibly difficult for OSFM to enforce, especially since the regulations do not specify API RP 1176 explicitly. Fatigue cracks are a serious threat to hazardous liquid pipelines in California since they are usually associated with cracks on the long seam of pipelines that were manufactured before the 1970s. OSFM has experienced two (2) significant pipeline failures due to fatigue cracks in 2015 and 2016. As a result, the proposed ILI regulations must be clear on how to predict the growth rate of these unrepaired fatigue cracks by referencing the 2nd edition of API RP 1160 in order to prevent these types of pipeline failures. Another reason for OSFM to exclude API RP 1176 is because this standard has recommended crack remediation criteria in Section 11.7 that is not as stringent as the proposed ILI regulations in **§ 2158. Required Validation, Field Evaluation and Repairs**. This difference will most likely create confusion for pipeline operators relating to crack remediation criteria. Because of these two reasons, the proposed ILI regulations have referenced the 2nd edition of API RP 1160 in lieu of the 3rd edition.

2. API Standard 1163, “In-line Inspection System Qualification” (Third Edition, September 2021)

This standard covers the qualification, selection, reporting, verification, validation, and use of ILI systems for onshore and offshore steel gas and hazardous liquid pipelines.

This includes, but is not limited to, tethered, self-propelled, or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. This standard is the most recent iteration, and it applies to both existing and developing technologies. In addition, this standard includes mandatory requirements for pipeline operators to verify and validate ILI performance as an integral component of their pipeline integrity management program. Thus, the 2021 edition should be incorporated into the proposed ILI regulations to reflect modern technology and best technical practices as well as improving the effectiveness of ILI and its results.

3. ASME/ANSI B31.4-2006, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids” (October 20, 2006)

The American Society of Mechanical Engineers (ASME) is recognized across the pipeline industry and state and federal regulatory agencies. The standard focuses on the process that an operator of a pipeline system can use to assess risks and make decisions about risks in operating a hazardous liquid pipeline in order to achieve a number of goals, including reducing both the number and consequences of pipeline accidents. Incorporating this standard ensures that accurate and consistent data is being submitted by intrastate hazardous liquid pipeline operators which is used in the review and evaluation of regulatory compliance.

This standard prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of liquid pipeline systems between production fields or facilities, tank farms, above or belowground storage facilities, natural gas processing plants, refineries, pump stations, ammonia plants, terminals, and other delivery and receiving points, as well as pipelines transporting liquids within pump stations, tank farms, and terminals associated with liquid pipeline systems. This standard also prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation and maintenance of piping transporting aqueous slurries of nonhazardous materials such as coal, mineral ores, concentrates, and other solid materials, between a slurry processing plant or terminal and a receiving plat or terminal. This standard is not the most recent iteration and covers significant portions of the OSFM’s inspection and regulatory program. These requirements will provide common evaluation techniques across industry, facilitating a common understanding of how operators can comply with and how the OSFM will evaluate compliance with the proposed regulations. The pipeline industry is very familiar with this standard and has been using them for years for procurement and operating purposes and the existing standard is well prepared, accepted by industry, and adequate. In addition, this standard is incorporated by reference in federal law at 49 C.F.R. § 195.3(c)(3), so industry is already familiar with the requirements, and they will merely apply them to the proposed regulations.

4. ASME FFS-1 2007, “Fitness-for-Service” (June 5, 2007)

ASME is recognized across the pipeline industry and state and federal regulatory agencies. The standard provides guidance for conducting fitness-for-service (FFS) assessments using methodologies specifically prepared for pressurized equipment and it focuses the methodologies that can be used to make run-repair-replace decisions to help determine if pressurized equipment containing flaws that have been identified by inspection can continue to operate safely for some period of time. FFS is an assessment that is carried out using the best practice industry standard. The FFS assessment evaluates the structural integrity of the asset/component to determine whether the asset/component is suitable for its intended use. This standard is the most current iteration, and the pipeline industry is very familiar with this standard and has been using them for years to evaluate pipeline integrity. Here, the pipeline industry will need to adapt existing practices to comply with the requirements set forth in the proposed regulations in **§ 2158. Required Validation, Field Evaluation and Repairs**. Incorporating this document provides direction to pipeline industry in understanding how to calculate burst pressures for crack like features and what features are required repair conditions. This narrows the approach pipeline operators may take in calculating and prioritizing repair conditions with an industry standard, while also allowing the OSFM to evaluate those conditions across all pipelines. This also allows the OSFM to apply a standardized evaluation of conditions present on pipelines across industry.

5. NACE International Standard Practice 0102-2010, "In-Line Inspection of Pipelines" (Revised March 13, 2010)
This standard is recognized across the pipeline industry in which it outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project. NACE International is incorporated in regulatory standard by other state regulators and the PHMSA. The guidelines pertaining to ILI data management and data analysis are included. NACE International is intended for use by individuals and teams planning, implementing, and managing ILI projects and programs. These individuals include engineers, operations and maintenance personnel, technicians, specialists, construction personnel, and inspectors. Users of this standard must be familiar with all applicable pipeline safety regulations for the jurisdiction in which the pipeline operates. This standard is not the most current iteration. However, this standard is incorporated in the proposed ILI regulations because the 2017 edition incorporates the Electromagnetic Acoustic Transducer (EMAT) ILI tool as a crack detection tool, which the OSFM found to be a valuable technology when evaluating and developing ILI inspections. This type of technology is classified differently by the federal regulatory team at PHMSA Hazardous Liquid Integrity Management Program, as they consider EMAT tool as an Other Technology in which 90-day notification is required. The proposed regulations incorporate this standard in **§§ 2156 and 2157**, where operators are required to evaluate specific types of pipe on specific intervals. This is a central part of the proposed regulations, because the OSFM, PHMSA, and industry have identified

specific types of pipe and pipe anomalies that present evaluation challenges. If improperly diagnosed, these issues can go unrecognized and lead to pipeline failures. This document will facilitate a common standard for developing ILI plans, selecting appropriate tools, and establishing appropriate intervals for inspection. In addition, the pipeline industry is very familiar with the 2010 standard and has been using for years to assess the integrity of its pipelines.

6. Form ILI-1, "Notification of Proposed In-Line Inspection", rev. 6/2025.
Each pipeline operator must notify the OSFM at least three working days prior to conducting an ILI assessment. The Form ILI-1 was developed to ensure accurate and consistent information is submitted about each assessment which allows the OSFM to efficiently review the ILI notification and track the ILI assessment.

SPECIFIC SECTION-BY-SECTION ANALYSIS
TEXT OF REGULATIONS

California Code of Regulations
Title 19. Public Safety
Division 1. State Fire Marshal
Chapter 14. Hazardous Liquid Pipeline Safety
Article 8. In-line Inspection Requirements

§ 2150. Definitions.

(a) Definitions applicable to this Article:

Necessity: It is necessary to include these definitions to carry out provisions of the In-line Inspection (ILI) regulations while clarifying the meaning of terms used. Both the OSFM and the regulated entities must understand key terms and the meaning attached to those terms to ensure all parties are effectively conveying the same information based on the same understanding of a term. Undefined terms could lead to uncertainty and confusion or inadvertently impact the interpretation of proposed regulations. Including the definitions section in the proposed regulations eliminates potential confusion and adds clarity by placing all relevant definitions and terms in one location immediately preceding the regulatory requirements.

(1) **Abandoned** means permanently removed from service.

Necessity: The OSFM observes that there are only active and abandoned pipelines. Operators sometimes classify pipelines as out of service when they are not actively shipping product. To clarify whether a pipeline is active or abandon will help industry know that even where they consider a pipeline out of service, our office will consider the pipeline to be active, unless it is abandoned.

(2) **Assessment** means in-line inspection to ascertain the integrity of a pipeline segment.

Necessity: The description of assessment included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. Without defining what is an assessment, operators may not implement and carry out the required integrity assessment as envisioned in the proposed regulations.

(3) **Bulk Loading Facilities** means all piping containing hazardous liquid substances or highly volatile liquid substances located within a refined products bulk loading facility that is owned by a common carrier and is served by a pipeline for that common carrier, and the common carrier owns and serves by pipeline at least five of these facilities in

the state.

Necessity: Defining bulk loading facilities clarifies the OSFM jurisdiction in relation to our overall authority under the California Pipeline Safety Act. Generally, our office does not engage in the regulation of certain facilities and pipelines not engaged in the transportation of hazardous liquid. This definition helps clarify that our office does not intend to include pipelines within bulk loading facilities in the proposed ILI regulations. This definition is consistent with statute in Government Code § 51010.5.

(4) **Cluster** means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria.

Necessity: Cluster is an amorphous term on its own and needs clarification to achieve the intended purpose of the proposed regulations. Clusters are subject to interaction criteria because multiple metal loss features closely located or adjacent to each other are subject to higher failure rates than independent metal loss features. Defining a cluster as at least two adjacent metal loss features will help clarify how operators classify metal loss features and importantly how those features work jointly and interact in relation to pipeline integrity. Additionally, this definition is consistent with the definition of Cluster in API Standard 1163, “In-line Inspection System Qualification” (Third Edition, September 2021), which is incorporated by reference in these proposed ILI regulations.

(5) **Crack** means a fracture type discontinuity characterized by a sharp tip and high ratio of length to width (e.g., stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks).

Necessity: The description of crack included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. Crack anomalies in the pipelines are among the most serious threats to the operation of the pipeline. Without defining what is a crack, operators may not implement and carry out the requirement for assessing and evaluating cracks as envisioned in the proposed regulations. Additionally, this definition is consistent with the definition of Crack in NACE International Standard Practice 0102-2010, “In-Line Inspection of Pipelines” revised March 13, 2010, (NACE SP0102), which is incorporated by reference in these proposed ILI regulations.

(6) **Crack-Like Flaw** means a flaw that may or may not be the result of linear rupture, but which has the physical characteristics of a crack when detected by a non-destructive examination technique.

Necessity: The description of what physical characteristics of a crack-like flaw included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. Cracking is one of the most serious failure mechanisms because of pressure cycle induced fatigue crack growth of defects. Without defining what is the physical characteristics of crack-like flaw operators may not implement and carry out the requirement for crack-like flaw as envisioned in the proposed regulations. Additionally, this definition is consistent with the definition of Crack-like Flaw in ASME FFS-1 2007, “Fitness-For-Service” June 5, 2007, (ASME FFS-1/API 579), which is incorporated by reference in these proposed ILI regulations.

(7) **Environmentally Assisted Cracking (EAC)** means corrosive attack of the pipe metal caused by exposure to specific environments either internal or external to the pipe and resulting in any of several forms of metal cracking. EAC includes, but is not limited to, hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), sulfide-stress cracking (SSC), or stress corrosion cracking (SCC).

Necessity: This definition further clarifies the definition of “Crack” provided in this section. It is necessary to include this definition because cracking can occur as a result of multiple factors internal and external, this definition further emphasizes the importance of operators considering all factors when evaluating crack and crack like flaws in pipe. EAC is a specific type of cracking that requires analysis for determining assessment intervals because they are time dependent. This type of cracking may require special attention due to the environment it is in compared to other types of cracks or crack-like flaws. Therefore, a definition of EAC is needed to clarify that not all cracks are to be treated the same in assessment for purposes of the proposed regulations. This definition is also consent with the definition of EAC in API RP 1176, 1st Edition, July 2016 (Recommended Practice for Assessment and Management of Cracking in Pipelines).

(8) **General Corrosion** means uniform or gradually varying loss of wall thickness over an area.

Necessity: The description of general corrosion included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. Without defining what is general corrosion, operators may not implement and carry out the requirement for general corrosion as envisioned in the proposed regulations. Additionally, this definition is consistent with the definition of General Corrosion in ASME/ANSI B31.4-2006, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids” March 31, 2006, which is incorporated by reference in these proposed ILI regulations.

(9) **In-Line Inspection (ILI)** means the inspection of a pipeline from the interior of the pipe using an in-line inspection tool.

Necessity: Pipeline integrity can be determined through several methods. Defining what method is needed and the manner in which that evaluation is conducted eliminates confusion and informs the regulated community how the OSFM expects integrity data to be gathered.

(10) **Sizing Accuracy** means the accuracy with which an anomaly's dimension or characteristic is reported.

Necessity: ILI tools are an effective means of assessing the integrity of a pipeline and broadening their use will improve the detection of anomalies and prevent or mitigate future accidents. The description of sizing accuracy included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. Both the OSFM and the regulated entities must understand key terms and the meaning attached to those terms to ensure all parties are effectively conveying the same information based on the same understanding of a term. Additionally, this definition is consistent with the definition of Sizing Accuracy in API RP 1176 (Assessment and Management of Cracking), 1st Ed.

(11) **Stress Corrosion Cracking (SCC)** means a form of cracking produced by the combined application of tensile stress (residual or applied), a corrosive environment, and steel that is susceptible to SCC.

Necessity: The description of stress corrosion cracking included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. SCC is one of several identified integrity threats for pipeline systems and it can lead to unexpected failure of the pipe materials due to tensile stress and elevated temperature. Without defining what is stress corrosion cracking operators may not implement and carry out the requirement for stress corrosion cracking as envisioned in the proposed regulations. Additionally, this definition is consistent with the definition of SCC in API RP 1176 (Assessment and Management of Cracking), 1st Ed.

(12) **Threats** mean external corrosion, internal corrosion, stress corrosion cracking, third-party damage/mechanical damage, manufacturing-related defects, construction-related defects, incorrect operational procedure, equipment, and weather-related and outside force.

Necessity: The description of what are the types of threat included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. There are numerous categories in identifying potential threats to the pipeline system. Thus, the risk assessment, integrity assessment, and mitigation activities should be addressed accordingly. Without defining what are the types of threat that operators may not implement and carry out the requirement for identifying threats as envisioned in the proposed regulations. The nine (9) integrity threats defined are consistent with the definition in ASME B31.8S-2004 (Managing System Integrity of Gas Pipelines), except security.

(13) **Validation Dig** means checking the accuracy of ILI results against empirical

evidence, observations, or field measurements.

Necessity: The description of validation dig included in the proposed ILI regulations is necessary because the term is used throughout the proposed regulations. Comparison of ILI-reported anomaly data and field measured data is a critical component to ensure that the ILI meets the performance specification. In some cases, operators may seek validation through computer programming or other methods. It is necessary to clarify physical evidence and field measurements are required, not extrapolated data without verification. Without defining what is a validation dig, operators may not implement and carry out the requirement for performing validation dig as envisioned in the proposed regulations.

§ 2151. Incorporated by Reference.

(a) This Article incorporates by reference the following standards:

Necessity: The subsections state which standards are being incorporated by reference.

(1) American Petroleum Institute Recommended Practice (API) 1160, “Managing System Integrity for Hazardous Liquid Pipelines” (Second Edition, September 2013).

(2) API Standard 1163, “In-line Inspection System Qualification” (Third Edition, September 2021).

(3) ASME/ANSI B31.4-2006, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids” October 20, 2006, (ASME/ANSI B31.4).

(4) ASME FFS-1 2007, “Fitness-For-Service” June 5, 2007, (ASME FFS-1/API 579).

(5) NACE International Standard Practice 0102-2010, “In-Line Inspection of Pipelines” revised March 13, 2010, (NACE SP0102).

(6) Form ILI-1, “Notification of Proposed In-Line Inspection”, rev. 6/2025.

Necessity: The OSFM has incorporated five (5) industry standards and one (1) form to ensure that accurate and consistent methodology and practice are used by operators to address and report the integrity of their pipeline systems. These standards have been developed by experts in their field over many years and incorporate lessons learned. Some operators currently use the identified standards and should be familiar with the content of the publications already. However, following the standards identified in this subsection will ensure that pipeline operators are implementing consistent practices across industry. Additionally, the standards will be used by the OSFM in assessing regulatory compliance, therefore the regulated entity benefits from known factors that could impact their compliance obligations.

(b) In the event of any differences between these regulations and the documents incorporated by reference then the provisions of this Article shall govern. Where a specific provision varies from the general provision the specific provision shall apply.

Necessity: This subsection is necessary because there may be unintended conflicts between the documents incorporated by reference and the language proposed in the regulations and Article. Every attempt was made by the OSFM to ensure that no conflicts existed or were addressed in the proposed language. However, this provision provides the clarity of controlling authority needed by the regulated entity in the event an unanticipated conflict arises. Without this provision operators and the OSFM could experience unintended difficulties in identifying standards or requirements that conflicted across documents incorporated by reference and the language of the proposed regulations.

§ 2152. Pipelines Subject to This Article.

All segments of intrastate hazardous liquid pipelines as specified in Government Code §§ 51010 et seq. are subject to this Article, including pipelines meeting the criteria identified in §§ 2155 and 2156.

Necessity: The proposed regulation conforms the OSFM's statutory authority in Government Code §§ 51010 et seq. In addition, the proposed regulation addresses several recommendations from NTSB and statutory mandates to OSFM concerning areas where the risk of a pipeline release could have significant impact to the public, property, and environment. This section clearly identifies that only pipelines subject to OSFM authority are required to comply with the regulations.

§ 2153. Exemptions.

(a) Abandoned pipelines are exempt from this Article.

(b) Bulk loading facilities are exempt from this Article.

(c) An operator may file for an exemption from this Article by demonstrating that the construction (i.e., length, diameter, operating pressure, or location) of a pipeline cannot be modified to accommodate the passage of an ILI.

(1) An operator shall submit documentation and information with supporting arguments in favor of exemption to the Office of the State Fire Marshal (OSFM) in accordance with § 2160.

(2) The OSFM will provide an approval or rejection response to the operator within 60 days based upon review of the materials provided.

(3) The OSFM may revoke an exemption on pipelines subject to this regulation based on new technologies or in the interest of public safety.

Necessity: The OSFM intends to identify pipeline anomalies and issues prior to failure. In some cases, it may be impossible for a pipeline to be inspected with an ILI tool due to construction and design parameters limiting tool availability. In those rare cases where a tool cannot be used, a pipeline would be faced with the potential that it must be shut down. This provision was included so pipelines that cannot accommodate ILI tools may continue to operate based on a written justification and supporting documentation submitted to OSFM. An exemption may no longer be applicable because of developments in new technologies that allow for an ILI tool to be used in pipelines that were not able to accommodate an ILI tool.

§ 2154. Accommodation of Instrumented Internal Inspection Devices.

Except for those pipelines listed in § 2153, all segments of intrastate hazardous liquid pipelines shall be able to accommodate the passage of instrumented internal inspection devices by January 1, [XXXX].

Necessity: Regulations already require that new and replaced pipelines accommodate ILI tools. Pipeline segments covered by this proposed ILI regulation will need to be retrofit to accommodate ILI tools within 5 years from the ILI regulation adoption date. This time frame will provide industry with sufficient time to implement this provision and allows the industry to prioritize retrofits and replacements based on age or other factors. In addition, it reduces the mileage of pipeline potentially needing to be replaced before it has reached the limit of its operational life. The OSFM determined that the timeline strikes the appropriate balance between the need for upgrades with the operational challenges of making these changes, while keeping in mind the possibility of avoiding additional pipeline failures, spills, and resultant environmental damage.

§ 2155. Higher Risk Pipelines.

(a) Definitions for purposes of this section.

(1) “Defect” refers to manufacturing or construction defects.

(2) “Leak” or “reportable leak” means a rupture required to be reported pursuant to Government Code § 51018, not including leaks during a certified hydrostatic pressure test.

Necessity: These definitions are provided in statutory authority in Government Code §§ 51010 et seq. They must be incorporated because they clarify what issues will draw a pipeline in to the category of higher risk pipelines. This is an important delineation between a standard pipeline and a pipeline that has a defect or leak, as those pipelines are required to undergo more strenuous testing programs.

(b) For purposes of this section, a leak which is traceable to an external force, but for which corrosion is partly responsible, shall be deemed caused by corrosion.

Necessity: This clarification is necessary because pipeline failures may occur due to an external force, such as a landslide damaging a pipe, and corrosion is present in the area of a failure. This is important because the corrosion may be partly responsible for the failure. Hence, if corrosion is present, the failure is considered caused by corrosion and placed on the higher risk pipeline list. This removes uncertainty regarding how to classify failures that are partly responsible due to corrosion and external force.

(c) A pipeline which meets any of the following criteria shall be placed on the State Fire Marshal's list of higher risk pipelines until five (5) years pass without a reportable leak due to corrosion or defect.

(1) Have suffered two or more reportable leaks due to corrosion or defect in the prior three (3) years.

(2) Have suffered three or more reportable leaks due to corrosion, defects, or external forces, but not all due to external forces, in the prior three (3) years.

(3) Have suffered a reportable leak due to corrosion or defect of more than 50,000 gallons, or 10,000 gallons in a high consequence area as defined by 49 C.F.R. § 195.450, in the prior three (3) years; or have suffered a leak due to corrosion or defect which the State Fire Marshal finds has resulted in more than 42 gallons of a hazardous liquid within the State Fire Marshal's jurisdiction entering a waterway in the prior three (3) years.

Necessity: The above criteria are specified by statute in Government Code §51013.5(f)(1)-(3) and in federal regulation in 49 C.F.R. § 195.450. Our office incorporated those requirements here so the regulated community can find the criteria in one location and need not search the government code and regulations to determine if their pipeline meets higher risk classification due to leak or defect.

(d) Within 30 days of the date of eligibility, the pipeline operator shall report to the OSFM any pipeline which satisfy the criteria in subsection (c) in accordance with § 2160. The pipeline shall be placed on the list retroactively to the date on which it became eligible for listing.

Necessity: The OSFM monitors all pipelines for failure and leaks. However, pipeline operators will know before the OSFM if a failure has occurred. By requiring operators to report failures to the OSFM within 30 days our office can take appropriate administrative action quickly and work with the operator to bring them into compliance with new requirements they are subject to as a higher risk pipeline. Design defects, leaks, and corrosion are all variable threats to pipeline integrity. Some may progress more rapidly than others. Requiring a 30 day reporting period will allow the OSFM and the operator to work together to identify other potential threats or risks and move to address them before another failure occurs.

(e) Within 60 days of the date of eligibility, the pipeline operator shall submit relevant information to the pipeline eligibility including but not limited to spill volume, commodity, location, accident investigation report, and metallurgical testing report to OSFM in accordance with § 2160.

Necessity: Operators are required to assist in the investigation of all failures. However, at times it has been difficult to obtain important information regarding pipeline failures in a timely manner. This provision includes a time deadline for providing information to the OSFM that will assist in determining ongoing pipeline risks and identify steps going forward that an operator can take to reduce risk.

§ 2156. In-line Inspections (ILI).

(a) An operator of a pipeline shall assess the integrity of the line pipe by ILI tools.

Necessity: Currently, pipeline operators can utilize hydrostatic testing as an alternative integrity assessment even if the pipeline is able to accommodate ILI tools. Unfortunately, hydrostatic testing does not provide quantitative information about the critical anomalies that may fail after the hydrotest is successfully completed. By requiring the operator to assess the pipeline with ILI tools, operators will obtain data relating to those features and take the appropriate actions to evaluate and remediate those conditions. PHMSA has recently modified 49 C.F.R. § 195.452(n) to require the hazardous liquid pipeline operators to retrofit their pipelines to accommodate instrumented internal inspection devices by July 2, 2040. This subsection will accelerate the date to 5 years from the ILI regulation adoption date so that pipeline operators can perform assessments on their pipelines utilizing ILI tools sooner than under federal standards. This will avoid future spills and reduce the resultant economic and environmental impacts.

(b) In choosing the ILI tools for the integrity assessment of each pipeline, an operator shall take action to address threats that it has identified. The tools shall be selected to effectively detect and size the three (3) most likely threats of failure associated with the pipeline and in accordance with Table 1 of NACE International Standard Practice 0102-2010, “In-Line Inspection of Pipelines”.

Necessity: By requiring the operator to select the appropriate ILI tools for addressing the three (3) most likely threats of failure, this proposed ILI regulation will reduce the probability of failure from those threats. The industry standard, NACE International Standard Practice 0102-2010, “In-line Inspection of Pipelines”, is already incorporated by reference in federal regulations at 49 C.F.R. § 195.591; however, this language takes it one-step further to confirm that the three (3) most likely threats are assessed with a corresponding ILI tools that can not only detect, but also size those features. This proposed regulation ensures operators effectively use their resources by mitigating those likely threats with the appropriate ILI tools that can provide key information, such as: accurate anomaly profiles.

(c) Pipelines that consist of the following pipe shall utilize an ILI tool that is capable of detecting and sizing long seam weld anomalies or defects in accordance with Table 1 of NACE International Standard Practice 0102-2010, “In-Line Inspection of Pipelines.”

(1) Low-frequency electric resistance welded (LF-ERW) pipe

(2) Pipe with unknown longitudinal seam weld

(3) Pipe with a seam factor less than 1.0 as defined in 49 C.F.R. § 195.106(e)

(4) Electric flash welded (EFW) pipe

(5) Lap-welded pipe

Necessity: The regulation calls for operators of older pipelines with susceptible longitudinal seams, compared to modern day pipelines, to utilize ILI tools that can detect and size longitudinal weld anomalies in accordance with NACE International Standard Practice 0102-2010, “*In-Line Inspection of Pipelines*”. These susceptible longitudinal seams include low-frequency electric resistance welded (LF-ERW) pipe, pipe with unknown longitudinal seam weld, pipe with a seam factor less than 1.0 as defined in 49 C.F.R. §195.106(e), electric flash welded (EFW) pipe, or lap-welded pipe. Historically, these types of longitudinal seams can fail through several mechanism including cracks, selective seam weld corrosion, or other weld anomalies at or along the long seam. The type of ILI tools that are specified in NACE SP0102-2010 is consistent with the type of tools recommended in the DOT’s sponsored study by Kiefner & Associates TTO Number 5 “*Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*”. Without identifying the specific types of pipe and the ILI tool standards to be used, operators may inadvertently choose an ILI technology that is less effective at detecting anomalies or defects that this regulation is designed to identify.

(d) Pipelines that consist of buried and insulated pipe shall utilize an ultrasonic ILI tool that is capable of detecting and sizing metal loss anomalies in accordance with Table 1 of NACE International Standard Practice 0102-2010, “In-Line Inspection of Pipelines”.

Necessity: The outer jacket and thermal insulation of buried and insulated pipe prevents the adequate corrosion control monitoring of the cathodic protection currents due to the phenomenon called “Shielding”. In addition, an ineffective cathodic protection system and its compromised corrosion control monitoring program due to the thermally insulated pipe allow undetected and rapid corrosion to occur without other safety measures being put into place. NACE considers ineffective or only partially effective cathodic protection a special condition, such as: disbonded coatings, thermal insulating coatings, shielding, etc. and it may be a warranted deviation from the standard inspection process. Thus, thermally insulated pipe needs to be inspected at routine time intervals to address the integrity of its pipelines, such as: more frequent ILI assessments. Buried and insulated pipelines present unique risks that are not present on non-insulated pipe. Because of these unique risks, specific tools are more effective in detecting defects and anomalies that would otherwise go unidentified or identified incorrectly regarding size, spacing, depth, etc. This provision calls special attention to the challenges faced by buried insulated pipe and the need for operators to utilize appropriate ILI tools to obtain relevant data that may otherwise be overlooked.

(e) Pursuant to Government Code § 51013.5, the OSFM may determine the type of ILI tool used, in the interest of public safety.

Necessity: The OSFM anticipates requiring an operator to utilize a particular ILI tool to assess a specific threat that may not be a part of the three (3) most likely threats self reported by an operator. Direction by OSFM to an operator to run a specific tool may arise in various situations, but is especially true after a pipeline accident in which an unlikely threat caused the failure of a pipeline. ILI technology advances regularly and new novel technologies may prove to be more effective than existing tools utilized today. The OSFM may find these technologies superior to existing technologies identified in these regulations and direct an operator to utilize tools other than those identified by the regulated community. This provision also allows the OSFM to direct an operator to utilize tools that they have not fully contemplated to address our offices specific concerns as a regulatory oversight agency.

§ 2157. Assessment Intervals.

(a) An operator shall perform an ILI of the line pipe at least once every 60 months. However, the criteria used for determining assessment intervals shall be applicable for the range of relevant threats. The operator shall consider the following items when determining the assessment interval:

Necessity: The California Elder Pipeline Safety Act incorporates all federal statutes and regulations through Government Code §§ 51010.6 and 51011. Those sections incorporate federal regulation 49 C.F.R. § 195.452, which specifies that integrity assessments must be performed at least every five (5) years. However, there are certain time-dependent threats that may have accelerated anomaly growth rates in which a more frequent integrity assessment interval than five (5) years may be warranted. Such as with buried insulated pipelines. The intent of this regulation is to define a maximum integrity assessment interval for ILI tool runs to be once every five (5) years; however, it is not for operators to default the integrity assessment interval to once every five (5) years. Varying risk factors will determine an appropriate inspection interval for a specific pipeline. This provision is designed to prevent operators from defaulting to a five (5) year interval, but to set up a desired interval based on risk.

(1) An operator shall establish the assessment intervals based on the risk factors, the analysis of ILI results from the previous integrity assessment(s), including anomaly growth rate, tool tolerance, and other information analysis as defined in 49 C.F.R. § 195.452(e) and §195.452(g).

Necessity: It is critical that operators determine the frequency of integrity assessments based off of several factors, particularly the anomaly growth rate of time-dependent threats, such as: corrosion and cracks. To support the importance of determining anomaly growth rate, the NTSB issued Safety Recommendation P-12-3 to PHMSA, dated July 25, 2012, which insisted that 49 C.F.R. § 195.452 be revised to clearly state how operators determine the time-dependent anomaly growth rate. This regulation will plainly require operators to utilize the previous ILI tool runs to determine the anomaly growth rate. In addition, other information including, but not limited to, pipeline operating conditions (hoop stress, pressure cycling, operating temperature, etc....), pipeline characteristics (coating, type of longitudinal seams, wall thicknesses, pipe grade, etc.…), and results of examinations of exposed portions of buried pipelines must be integrated when determining the integrity assessment interval. In some instances, operators have collected appropriate data but failed to incorporate it into pipeline operations and maintenance. This provision is designed to address those concerns.

(2) For pipelines that have time-dependent threats such as external corrosion, internal corrosion, selective seam corrosion, stress corrosion cracking, or other environmentally-assisted corrosion mechanisms, the assessment frequency of the ILI tool that can detect and size these anomalies shall be based on the anomaly growth rate in accordance with Section 9 of the American Petroleum Institute Recommended Practice 1160, “Managing System Integrity for Hazardous Liquid Pipelines” (Second Edition, September 2013). However, the assessment interval cannot exceed 60 months regardless of the anomaly growth rate.

Necessity: This subsection is essential to integrity management since pipelines with certain types of pipe, including longitudinal seam welds, are vulnerable to failures along the long seam. There are several processes in which these longitudinal long seams may fail including selective seam weld corrosion, cracks found along the longitudinal seam, and longitudinal weld defects as documented in DOT’s RSPA sponsored study by Kiefner & Associates TTO Number 5 “*Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*”. The anomaly growth rate for these failure mechanisms can differ significantly; however, Section 9 of American Petroleum Institute Recommended Practice 1160 provides a robust process to determine the anomaly growth rates and how to determine reassessment intervals. Anomaly growth rate provides insights into how quickly a defect on a pipeline is progressing. By calculating the anomaly growth rate, pipeline operators can estimate when an anomaly may reach a critical size or condition that could compromise the integrity of the pipeline. This allows for proactive maintenance and scheduling of assessments or repairs before the anomaly poses a significant risk. Determining the appropriate integrity assessment interval based on the anomaly growth rate helps optimize resource allocation. By aligning inspection and maintenance activities with the rate of anomaly growth, operators can allocate resources efficiently and effectively. Calculating the anomaly growth rate and using it to determine the assessment interval aligns with the principles of integrity management and compliance with relevant regulations. Regardless of the results, this draft subsection caps the integrity assessment interval to at least once every five (5) years based upon the research and recommendations of industry groups and government oversight agencies.

(3) For pipelines which meet the criteria in § 2156(c) the assessment frequency of the ILI inspection tool that can detect and size the long-seam weld anomalies shall be based on the anomaly growth rate in accordance with Section 9 of the American Petroleum Institute Recommended Practice 1160, “Managing System Integrity for Hazardous Liquid Pipelines”. The assessment interval cannot exceed 60 months regardless of anomaly growth rate.

Necessity: There have been several pipeline failures in which time-dependent threats such as corrosion was the primary cause of the accident. NTSB Safety Recommendation P-12-3 to PHMSA, dated July 25, 2012, directly recommends that regulators revise their regulations to clearly determine the anomaly growth rate of cracks such as Stress Corrosion Cracking and selective seam weld corrosion. The anomaly growth rate for these failure mechanisms can differ significantly; however, Section 9 of API RP 1160 provides a robust process to determine the anomaly growth rate and how to determine reassessment intervals. Understanding the anomaly growth rate of these anomalies helps in assessing the associated risks. By considering the rate at which anomalies are growing, operators can evaluate the potential for future failures and the likelihood of the anomaly reaching a critical size within a specific time frame. This information is crucial for determining the appropriate integrity assessment interval to ensure the pipeline's continued safe operation. Calculating the anomaly growth rate and using it to determine the integrity assessment interval aligns with the principles of integrity management and compliance with relevant regulations. Regardless of the results, this draft subsection caps the integrity assessment interval to at least once every five (5) years.

(4) For pipelines which meet the criteria in § 2156(d), an ILI shall be conducted annually. Inspections shall occur at least six (6) months after prior inspection but not

more than 12 months from the prior inspection.

Necessity: The federal pipeline safety regulations require hazardous liquid operators to (1) have adequate cathodic protection to prevent external corrosion of the pipeline, and (2) routinely monitor the level of cathodic protection at sufficient locations to ensure continued corrosion protection for all segment of the pipeline. The OSFM has inspected and investigated several buried and insulated pipelines that have failed within the last ten (10) years including the Refugio oil spill that occurred near Goleta, CA in 2015. Buried and insulated pipelines most likely have an accelerated corrosion growth rate due to several factors including ineffective cathodic protection due to the shielding effect of the insulation and the hot temperature of insulated pipe which increases the corrosion rate significantly. This failure process is documented thoroughly in PHMSA's Failure Investigation Report that was released on May 2016 after the May 19, 2015 crude oil spill in Santa Barbara County, CA. One of the most important ways to prevent pipeline failure is to have more frequent integrity assessments to identify and remediate the critical anomalies that may cause pipeline failures and to calculate more accurate corrosion growth rates with the ILI run comparisons. As a result, OSFM is proposing that pipelines that are buried and insulated must perform integrity assessments at least once every year. Operators may have to perform the integrity assessments more frequent than once every year if the anomaly growth rate requires it as described in Subsection 2157(a)(3).

(5) For newly acquired pipelines for which the new operator does not have any data relating to the previously established assessment interval, an operator shall complete the ILI of a newly acquired segment of line pipe within one (1) year from the date that the pipe is acquired. The tools shall be selected to effectively detect and size the three (3) most likely threats of failure associated with the pipeline and in accordance with Table 1 of NACE International Standard Practice 0102-2010, "In-Line Inspection of Pipelines".

Necessity: The OSFM noticed several pipeline acquisitions in which an integrity assessment was not performed at the correct interval which resulted in a greater risk of failure when the critical anomalies were not identified and remediated timely. This language in this subsection ensures that newly acquired pipeline, with unknown integrity assessment intervals, must have an integrity assessment performed within a year so that the new operator can collect and review more recent (and therefore more accurate) integrity information on their new pipeline to determine whether further actions including remediation is needed to lower the risk of failure. The tools in which the operator select must be able to effectively size and detect the three (3) most likely threats of failure and in accordance with Table 1 of NACE International Standard Practice 0102-2010, "*In-Line Inspection of Pipelines*".

(6) For higher risk pipelines which meet the criteria in § 2155(c), an ILI shall be conducted every two (2) years until five (5) years pass without a reportable leak due to

corrosion or defect on that pipeline.

Necessity: The risks posed by higher risk pipelines, pipelines that have experienced a release due to corrosion or defect, are an emphasis of overarching statute directing additional testing and proven track record of avoiding spills following the 5 years after a reportable release has occurred. This provision integrates statutory requirement into the regulations to avoid confusion. It is necessary to include this provision because pipelines that experience a failure due to corrosion or defect may experience additional releases. The additional ILI testing will provide more frequent data to understand the risks a particular pipeline faces, and will provide a road map for more effective risk management along that pipe in line with statutory requirements.

(b) Pursuant to Government Code § 51013.5, the OSFM may determine more frequent assessments, in the interest of public safety.

Necessity: The OSFM anticipates requiring an operator to perform an ILI to assess a specific threat as soon as possible after a pipeline accident to ensure that the threat is mitigated throughout the pipeline. This integrity assessment may result in a more frequent interval than what the operator had previously established and is afforded under Government Code § 51013(h).

§ 2158. Required Validation, Field Evaluation and Repairs.

(a) An operator shall comply with the requirements in § 2158(d) if a condition that could adversely affect the safe operation of a pipeline is discovered when complying with paragraphs §§ 2158 (b) and (c).

(b) **Discovery of condition.** For the purpose of § 2158, discovery of a condition occurs when an operator has adequate information to determine that a condition exists and presents a potential threat to the integrity of the pipeline. Adequate information includes, but is not limited to, when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections, or when an operator receives the final internal inspection report. An operator shall promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition and make the determination required under paragraph § 2158(d). If the operator believes that 180 days are impracticable to make a determination about a condition found during an integrity assessment, the pipeline operator shall notify OSFM in accordance with § 2160 and provide an expected date when adequate information will become available.

Necessity: The OSFM adopted Code of Federal Regulation 49 C.F.R. Part 195 to apply to intrastate hazardous liquid pipelines in California. As such, pipeline operators are required to comply with 49 C.F.R. § 195.416 and § 195.452(h). These sections address the actions for operators to take when there are integrity issues in their pipeline. The

"Discovery of condition" is explained in 49 C.F.R. § 195.416 and § 195.452(h)(2). This proposed regulation section is required to limit the time for operators to address the integrity issues that they discovered during the integrity assessment, information analysis or in-line inspection of the pipelines. The element of discovery of a condition has led to ambiguity in reporting and prompt resolution to discovered conditions that has resulted in disproportionally large amounts of time taken by an operator to report issues on pipelines. In addition, it provides information to clarify when an operator has adequate information about a condition to determine that it presents a potential threat to the integrity of the pipeline.

(c) **Validation Digs.** Prior to the final ILI report being received, the pipeline operator shall perform at least three (3) separate validation digs that do not interact with each other. At a minimum, the pipeline operator shall perform validation digs in accordance with Level 2 or Level 3 of API 1163, In-line Inspection System Qualification.

(1) These validation digs shall meet the anomaly's depth sizing accuracy listed in the ILI tool specification. If the anomalies found during the validation digs do not meet the depth sizing accuracy, additional validation dig(s) shall be performed until three (3) separate validation digs that do not interact with each other meet the depth sizing accuracy.

(2) The conditions listed in § 2158(d) cannot be used to replace validation digs.

Necessity: Pipeline operators are required to assess the integrity of the line pipes by in-line inspection tool to detect and identify sizing defects in the pipelines. These inspections often reveal hundreds of defects with probable sizing accuracy provided by the tool vendor. However, the inspection is not complete until the reported features have been verified in the field. The operators must perform the validation digs to confirm that in-line inspection data matches the actual defects. Three (3) validation digs are selected as two (2) may have a lower chance of being accurate, and hence the third will increase the confidence level of one of the former two (2) digs. In addition, DOT's Inspector General issued an audit in September 2006 to address uncertainties, such as: under-sizing and over-sizing, in the characterization of defects using in-line inspection. Thus, ILI vendors and operators must account for potential inaccuracies in tool indications in their evaluation of ILI results. Furthermore, operators are required to integrate relevant information on the condition of line pipe in making decisions on excavation timing and other mitigative actions. Tool tolerances should be considered as part of the data integration process. Information on tool tolerances should be used to assure that defects requiring early excavation and mitigative action are properly identified and characterized. This does not necessarily mean simply adding the vendor-supplied tolerance value to reported depth of indications. Several sources of data may be used, in conjunction with vendor-supplied tool tolerances, to characterize pipeline defects. These include results of previous excavations, validation digs, results of concurrent inspections, and comparison to prior inspections. Uncertainties in this data should also be considered. In addition, information on tool tolerances may be incorporated in engineering analysis such as "probability of exceedance" to help operators prepare a comprehensive defect remediation plan and schedule future assessments. Pipeline operators have the flexibility to apply processes specific to their unique risks by utilizing these techniques when evaluating specific pipeline defects. Tool tolerances are not the only uncertainty associated with assessment results and are therefore not the only factor to be considered in evaluating the quality of internal inspection data and in making excavation timing and mitigation decisions. Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in § 2158(d), are promptly identified. Without field evaluation digs, there is no way of knowing the accuracy of the data provided from the ILI tool. In the absence of verification, the data is simply collected and not evaluated for the risks present on a particular pipeline.

(d) **Required Repair Conditions**.

(1) **Immediate repair conditions.** The following conditions shall be field evaluated and remediated within three (3) days from the discovery of condition and the evaluation and remediation of immediate repair conditions shall be completed prior to the next integrity assessment interval listed in § 2157:

(A) All conditions listed in 49 C.F.R. § 195.452(h)(4)(i).

(B) Any indication of stress corrosion cracking.

(C) Any indication of selective seam weld corrosion (SSWC) that upon excavation are determined to be SSWC.

(D) Crack or crack-like feature(s) with a predicted burst pressure less than 1.1 times maximum operating pressure (MOP) as calculated using crack-like flaw evaluation method ASME FFS-1/API 579-1.

(E) Crack or crack-like feature(s) with a predicted depth greater than or equal to 40% of the pipe nominal wall thickness regardless of dimensions.

(F) For buried and insulated pipelines, any cluster corrosion or general corrosion regardless of dimensions.

Necessity: The OSFM regulates the safety of intrastate hazardous liquid pipelines through certification from the United States Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA). The PHMSA requirements are the minimum requirements in which OSFM can build upon. However, OSFM may impose additional requirements on intrastate hazardous liquid pipeline operators for the protection of people, property, and environment. Furthermore, the NTSB's investigation into the 2010 crude oil pipeline rupture near Marshall, Michigan also recommended that PHMSA should revise Title 49 Code of Federal Regulations § 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable. Furthermore, all conditions identified by an integrity assessment or information analysis that could impair the integrity of the pipeline must be evaluated and scheduled for repair. This section meets the suggested Federal requirements noted above. It is imperative that conditions that merit repair be addressed, this section closes the loop on inspection and repairs designed to prevent failures.

(2) **60-day repair conditions.** All conditions listed in 49 C.F.R. § 195.452(h)(4)(ii) shall be field evaluated and remediated within 60 days from the discovery of condition and the evaluation and remediation of 60-day repair conditions shall be completed prior to the next integrity assessment interval listed in § 2157.

Necessity: The Federal pipeline safety regulations require hazardous liquid operators to evaluate and remediate the discovery of conditions as specified in § 195.452 within 60 days. Thus, anomalies that are not meeting criteria for "immediate repair condition" must be evaluated and remediated in timely manner. The Federal conditions are expanded here and applied to non-high consequence areas as mandated in the Elder California Pipeline Safety Act. Furthermore, all conditions identified by an integrity assessment or information analysis that could impair the integrity of the pipeline must be evaluated and scheduled for repair. This section meets the suggested Federal requirements noted above. It is imperative that conditions that merit repair be addressed, this section closes the loop on inspection and repairs designed to prevent failures.

(3) **180-day repair conditions.** The following conditions shall be field evaluated and remediated within 180 days from the discovery of condition and the evaluation and remediation of 180-day repair conditions shall be completed prior to the next integrity assessment interval listed in § 2157:

(A) All conditions listed in 49 C.F.R. § 195.452(h)(4)(iii).

(B) For buried and insulated pipelines, an anomaly that has a metal loss depth greater than 40% of nominal wall, regardless of dimensions.

(C) Crack or crack-like feature(s) with a predicted burst pressure less than 1.5 times MOP as calculated using crack-like flaw evaluation method ASME FFS – 1/API 579-1.

(D) Surface breaking laminations or laminations which intersect either the longitudinal weld seam or girth weld.

Necessity: The OSFM regulates the safety of intrastate hazardous liquid pipelines through certification from the United States Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA). The PHMSA requirements are the minimum requirements in which OSFM can build upon. However, OSFM may impose additional requirements on intrastate hazardous liquid pipeline operators for the protection of people, property, and environment. Furthermore, the NTSB's investigation into the 2010 crude oil pipeline rupture near Marshall, Michigan also recommended that PHMSA should revise Title 49 Code of Federal Regulations § 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable. Based on OSFM experience, buried and insulated pipelines have an accelerated corrosion growth rate due to several factors including ineffective cathodic protection due to the shielding effect of the insulation and the hot temperature of insulated pipe which increases the corrosion rate significantly. And the existence of lamination defect near the weld decrease the effective thickness of pipe and it reduces the mechanical properties such as impact toughness, tensile strength, etc. Furthermore, all conditions identified by an integrity assessment or information analysis that could impair the integrity of the pipeline must be evaluated and scheduled for repair. And anomalies are not meeting criteria for 'immediate repair condition' or '60-day repair condition' must be evaluated and remediated in timely manner. This section meets the suggested Federal requirements noted above. It is imperative that conditions that merit repair be addressed, this section closes the loop on inspection and repairs designed to prevent failures.

(4) **12-month repair conditions.** The following conditions shall be field evaluated and remediated within 12 months from the discovery of condition and the evaluation and remediation of 12-month repair conditions shall be completed prior to the next integrity assessment interval listed in § 2157:

(A) Any time-dependent anomaly, such as a metal loss, crack, or crack-like anomaly, that has an anticipated predicted burst pressure less than the established MOP prior to the next integrity assessment date. The anomaly growth rate must be calculated in accordance with Section 9 of the American Petroleum Institute Recommended Practice 1160, “Managing System Integrity for Hazardous Liquid Pipelines”.

(B) Anomaly with a metal loss depth greater than or equal to 40% of nominal wall, regardless of dimensions.

Necessity: The OSFM regulates the safety of intrastate hazardous liquid pipelines through certification from the United States Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA). The PHMSA requirements are the minimum requirements in which OSFM can build upon. However, OSFM may impose additional requirements on intrastate hazardous liquid pipeline operators for the protection of people, property, and environment. Above sections are required in the proposed ILI regulations to ensure that operators address those conditions in a timely manner. Furthermore, the NTSB's investigation into the 2010 crude oil pipeline rupture near Marshall, Michigan also identified the need to develop criteria for determining when a probable crack defect in a pipeline must be field evaluated and remediated, and the time limits be established for completing those mitigative actions. The NTSB recommended developing acceptable integrity assessment methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable. In addition, the metal loss depth greater than 40% of nominal wall should be evaluated and remediated to account for unexpected tool tolerance and anomaly growth rate. Furthermore, all conditions identified by an integrity assessment or information analysis that could impair the integrity of the pipeline must be evaluated and scheduled for repair. And anomalies are not meeting criteria for 'immediate repair condition', '60-day repair condition', or ‘180-day repair condition’ must be evaluated and remediated in timely manner. This section meets the suggested Federal requirements noted above. It is imperative that conditions that merit repair be addressed, this section closes the loop on inspection and repairs designed to prevent failures.

(5) **Types of Repairs.** All repairs shall be performed in accordance with Section 451.6.2.9 of ASME/ANSI B31.4-2006 “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids”, except the following types of repairs are not allowed:

(A) Deposition of weld metal

(B) Hot tapping

(C) Fittings

Necessity: The OSFM regulates the safety of intrastate hazardous liquid pipelines through certification from the United States Department of Transportation - Pipeline and

Hazardous Materials Safety Administration (PHMSA). The PHMSA requirements are the minimum requirements in which OSFM can build upon. However, OSFM may impose additional requirements on intrastate hazardous liquid pipeline operators for the protection of people, property, and environment. Above sections are required in the proposed ILI regulations as they make operators more responsible for repairs of the defects in timely manner, which will ensure the integrity of their pipeline. This language clarifies that an operator must evaluate all anomalous conditions, such as: any condition that is irregular, abnormal, deviates from the norm, etc. and operator must remediate those conditions that could reduce the integrity of a pipeline. This list will instruct operators and close the gap on the repair conditions that they should be prepared to evaluate and remediate. Furthermore, ASME B31.4-2006, table 451.6.2 (incorporated by reference, see 49 C.F.R. § 195.3), provides examples of permanent repair methods to address pipeline anomalies. While the table specifically addresses acceptable repair methods of liquid pipeline anomalies, the examples therein are informative for hazardous liquid pipelines. In the event the time to failure is too short in relation to the time scheduled for the repair, and it is not feasible to make a permanent repair at the time of anomaly discovery, methods documented in operations and maintenance procedures and proven by test, investigation, or experience that are outside of the examples listed in ASME B31.4-2006, table 451.6.2, may be used and considered a temporary repair. Regardless of whether a repair is permanent or temporary, it must restore serviceability and safe operation of the pipeline. A pipeline operator cannot operate a pipeline using unsafe repair methods, such as those listed.

§ 2159. Pressure Reduction.

(a) Until the remediation of a condition specified in § 2158(d)(1) is complete, an operator shall reduce the operating pressure of the affected pipeline by at least twenty (20) percent below the highest operating pressure actually experienced at the location of the defect within the two (2) months preceding the inspection or shutdown the affected pipeline.

Necessity: Pipeline rupture or failure is caused by the hoop stress developed in pipe wall due to the internal pressure in the pipeline. As the internal pressure caused by transporting hazardous liquid gradually increases, the risk of pipeline failure also increases. Hence, one method to lessen the risk of pipeline failure is to reduce the internal pressure. As stated previously, OSFM adopts Code of Federal Regulation 49 C.F.R. Part 195 for the regulations of intrastate pipelines in California. As such, pipeline operators are required to comply with Title 49, Part 195. § 195.452(h) addresses the actions for operators to take when there are integrity issues in their pipeline. 49 C.F.R. § 195.452(h)(2) states that an operator must calculate the temporary reduction in operating pressure using the formulas referenced in 49 C.F.R. § 195.452. The paragraph also states that if no suitable remaining strength calculation method can be identified, an operator must implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two (2) months prior to the date of inspection, until the anomaly is repaired. Thus, temporary pressure reductions add extra safety margin and serve to mitigate potential failure and release, and the safety impacts of repair delays.

(b) When an operator cannot meet the schedule for evaluation and remediation as specified in § 2158(d)(2), § 2158(d)(3), and § 2158(d)(4) and utilizes a temporary pressure reduction to address the required condition, the operator shall reduce the operating pressure by at least ten (10) percent below the highest operating pressure actually experienced at the location of the defect within the two (2) months preceding the inspection or shutdown the affected pipeline.

Necessity: The Code of Federal Regulations (49 C.F.R. Part 195) requirements are the minimum requirements in which OSFM can build upon. However, OSFM may impose additional requirements on intrastate hazardous liquid pipeline operators for the protection of people, property, and environment. The above section is required in the proposed ILI regulations to ensure that operators must take further remedial action or make repair of the defects in timely manner, which will ensure the safety of the pipeline. Thus, temporary pressure reductions add extra safety margin and serve to mitigate the safety impacts of repair delays.

(c) When a pressure reduction exceeds 365 days, the operator shall notify OSFM in accordance with § 2160 and explain the reasons for the remediation delay. An operator shall also take further action by reducing the operating pressure of the affected pipeline by an additional ten (10) percent to ensure the safety of the pipeline.

Necessity: The Code of Federal Regulations, 49 C.F.R. § 195.452(h)(1)(ii) required operators to notify regulating agency when a pressure reduction exceeds 365 days. It also required operators to take further remedial action to ensure the safety of the pipeline. The OSFM believes that a reduction of pressure by ten (10) additional percent of operating pressure will provide an additional safety margin until the conditions can be evaluated and remediated. In addition, OSFM believes that notification of extended delay will provide essential information on the repair conditions interfering with the operator’s ability to complete the evaluation and remediation. This further provides a greater understanding of the cause of repair delays in which it will help identify where extra actions can help. This notification will enable OSFM to intervene, if necessary, in order to facilitate the needed repairs and to evaluate the need for additional measures until remediation can be completed.

(d) An operator may be required to take further remedial action, as directed by the OSFM, to ensure the safety of the pipeline.

Necessity: Unanticipated conditions may give rise for the need to reduce operating pressure on pipelines beyond those situations enumerated above. For example, repair conditions that are extended beyond 365 days may no longer be feasible to operate a pipeline at only a 10 percent additional pressure reduction. This provision anticipates that potential outcome. The OSFM's experience has revealed that local permitting agencies may not have the necessary staff, resources, or expertise necessary to fully understand the engineering challenges faced in repairing conditions on pipelines. This typically results in an extended permitting timeline from discovery to completion of repairs. This subsection offers operators and the OSFM options in approaching pipeline integrity and continued operations while balancing potential pipeline failure due to conditions on a pipeline.

§ 2160. Notifications.

(a) Notifications to the OSFM shall be made via email to pipelinenotification@fire.ca.gov for the following:

(1) **Approval for integrity assessment.** An operator shall complete and submit to the OSFM In-Line Inspection Form ILI-1 (Notification of Proposed In-Line Inspection) for approval at least 30 days prior to performing any ILI on the pipeline.

Necessity: Operators will be required to complete and submit In Line Inspection Form ILI-1 (Notification of Proposed In-line Inspection) to the OSFM at least 30 days prior to performing any in-line inspection. The authorizing legislation requires operators to seek a waiver for utilizing an alternative integrity assessment method from the OSFM. Including this requirement in the proposed ILI regulations specifies how an operator must communicate the waiver requirement to the OSFM. Furthermore, this proposed section will allow the OSFM adequate time to review the waiver request. This section is necessary for the OSFM to conduct appropriate inspections that ensure compliance with Federal and State regulations, enhance public safety, and protect California's vital natural resources and the environment.

(2) **ILI tool runs.** A notification to OSFM shall be made at least three (3) days in advance of all ILI tool run dates. Any changes to the date of the ILI tool run shall be brought to OSFM's attention at least three (3) days prior to commencement of the tool run.

(3) **ILI reports.** Once the pipeline operator receives a copy of the preliminary and final report from the tool vendor, it shall be emailed to OSFM within three (3) days.

(4) **Required conditions and validation digs as specified in § 2158(c) of this Article.** A notification to OSFM shall be made at least three (3) days in advance of the anticipated validation dig date.

(5) **Pressure Reductions**. A notification to OSFM shall be made at least three (3) days in advance before the operator takes a pressure reduction to address an integrity issue.

Necessity: The Elder California Pipeline Safety Act requires operators to notify OSFM at least three (3) working days prior to conducting integrity assessment. The OSFM cannot eliminate this requirement from the rule. The requirement has been conditioned to require notification of integrity assessments that may substantially affect the schedule for carrying out the activities. We have revised this requirement to require operators to notify OSFM when the conditions 2 to 5 listed above exist. These requirements are made to help ensure that operators will be able to complete those activities in a timely manner and will provide OSFM an opportunity to verify those activities are in compliance with Federal and State regulations, enhance public safety, and protect California's vital natural resources and the environment.

(b) Extension.

(1) **Exceeding ILI tool deadline**. A notification to OSFM shall be made 90 days prior to the due date of the integrity assessment if the operator anticipates a delay in the ILI tool run which will exceed the assessment interval specified in § 2157 of this Article.

(2) **Exceeding deadline for required condition**. A notification to OSFM shall be made at least a week prior to the due date of the required condition if the operator anticipates a delay in the field evaluation and remediation which will exceed the deadline specified in § 2158(d) of this Article.

(3) All operators seeking extensions shall provide justification and documentation demonstrating good cause for delay to the OSFM for review and acceptance, in accordance with § 2160.

Necessity: Operators engage in pipeline integrity assessment activities that range in size and complexity from in-line inspection assessment to the evaluation and remediation of defects. This section provides the necessary clarification needed to avoid confusion of the type of notifications. If this section were not included, pipeline operators and the OSFM would be sending and receiving numerous integrity assessment notifications outside the goals of proposed ILI regulations. The definition necessarily narrows the field of notification requirements on the regulated entities and the OSFM to a known realm of possibilities as opposed to a general requirement to provide notification for any integrity assessment. These notifications further allow the OSFM to schedule inspections and timely review of upcoming activities on pipelines necessary for ensuring pipeline safety.

(c) Exemptions.

(1) A notification to OSFM shall be made 90 days prior to the timing of compliance specified in §2161 of this Article.

(2) All operators seeking exemptions shall provide documentation and information with

supporting arguments demonstrating that the construction of a pipeline cannot be modified to accommodate the passage of an ILI to the OSFM for review and acceptance.

Necessity: Some pipelines are inherently incapable of accommodating and ILI tool. Therefore, this section is needed so that operators can demonstrate that the construction (i.e., length, diameter, operating pressure, or location) of a pipeline cannot be modified to accommodate the passage of an ILI tool.

§ 2161. Timing for Compliance.

(a) No later than January 1, [XXXX], an operator of a pipeline shall prepare and follow a written ILI program that contains all the elements described in this Article.

Necessity: This section provides the groundwork for the regulated entities to understand the deadline requirements necessary for compliance under the proposed regulatory scheme. The timing for compliance will be one year from adoption of the proposed ILI regulations. Without this section the regulated entities may not recognize what pipelines are subject to the article's requirements or the date by which compliance must be achieved. This language is necessary for the OSFM and pipeline operators to meet the time sensitive compliance regime and remain consistent with the legislative intent to afford the regulated entities time to implement required actions once the regulations are final.

§ 2162. Record Retention.

(a) An operator shall retain records that demonstrate compliance with the requirements of this Article. At minimum, the following records shall be retained for the useful life of the intrastate pipeline:

(1) Notifications to OSFM

(2) Approval letters from OSFM

(3) ILI reports

(4) Field evaluation report

(5) Repair records

(6) Documents to carry out the requirements in this Article

(b) All documentation shall be made available to the OSFM upon request.

(c) When an operator divests its assets, it shall transfer all records listed in § 2162(a) to the new operator who acquired those assets.

Necessity: 49 C.F.R. Part 195 provides an extensive listing of records that should be kept, and documentation that should be developed and maintained for an integrity management program. In addition to these items, each operator may have documentation that is unique to its integrity management program operation or program results. Records associated with integrity management program activities such as internal inspection results, pipe repair and mitigation records, risk analysis results, and records associated with the implementation of other preventive and mitigative actions such as Emergency Flow Restriction Devices should be retained for the life of the pipeline system. The technical justification for changes to the assessment plans, the use of other technologies, and the extension for integrity assessment intervals beyond 5 years should also be retained for the life of the system. Documentation of integrity management program operational, analytical, and management processes should be kept up to date to reflect current practices and insights obtained from the integrity management program results. The retention of these documents will inform current and future owners and operators of the pipeline and will further help determine ILI assessments and identifying conditions and threats that require focused attention in maintaining pipeline integrity.

§ 2163. Intrastate, Interstate, And Other Non-Jurisdictional Pipelines.

(a) Should an interstate pipeline or other pipeline that is not currently under the jurisdiction of the State Fire Marshal, become reclassified as an intrastate pipeline or become jurisdictional to the State Fire Marshal, that pipeline shall be subject to all the requirements of this Article.

(b) Operators will have 12-months from the time the pipeline became jurisdictional to the State Fire Marshal conform to the requirements of this Article.

Necessity: One of primary goals of the proposed regulation is improving the protection of the public, property, and the environment by closing the regulatory gaps where appropriate. Including this section will ensure the regulatory scheme captures current and future pipelines that are jurisdictional to OSFM.

§ 2164 Enforcement.

The State Fire Marshal may take enforcement action for violations of this Article consistent with authority found in Government Code Sections 51010 et seq.

Necessity: It is necessary to include this section so the OSFM can take enforcement action where warranted to ensure compliance with the proposed regulations.