Pipeline and Facilities Program

California
Department of Conservation
Oil, Gas, & Geothermal Resources

AB 1420 Regulations – Questions and Answers

The purpose of these questions and answers is to help operators better understand new regulations through likely questions followed by short answers.

These questions and answers concern AB 1420 Part A regulation changes that are effective on October 1, 2018. Questions have been grouped below as general questions or specific questions about California Code of Regulations, Title 14, §§ 1760, 1774, 1774.1, and 1774.2.

General

1. **Q.** When will AB 1420 Part A regulations be effective?

A. October 1, 2018.

2. **Q.** What is considered "gas"?

A. "Gas" is now defined in § 1760(j) to mean any natural hydrocarbon gas coming from the earth.

3. **Q**. Are flowlines and gathering lines that contain associated or dissolved gas considered active gas pipelines?

A. In crude oil production, flowlines and gathering lines are not considered active gas pipelines when content is mostly liquid and may contain associated or dissolved gas. "Active gas pipeline" means an in-service pipeline that carries gas in gaseous or vapor phase and may contain fractional amounts of liquids, solids, and other non-hydrocarbon gases.

4. **Q**. My facility has gas lines, but there are no sensitive areas nearby. Is there anything I need to do to comply with these new regulations?

A. You will need to update your facility's pipeline management plan (PMP) by October 1, 2019, to include new data required by the AB 1420 Part A regulations. CCR § 1774.2(b) requires new information on preventive maintenance, list and map data for pipelines in sensitive areas, and a description of the product transferred in each pipeline. Please see the text of the regulations for more details on everything required in the PMP.

5. **Q**. My facility is a gas storage facility. Gas storage pipelines are already regulated by the California Public Utilities Commission (CPUC). Do I also have to apply AB 1420 regulations to my gas pipelines?

A. No, although AB 1420 regulations do apply, DOGGR and CPUC have a memorandum of understanding MOU that gives the CPUC primary authority over the design, construction, testing, operation, and maintenance of gas gathering, transmission, and distribution piping systems at underground gas storage facilities. Therefore, the provisions of AB 1420 are not enforced at gas storage facilities. However, any oil or gas *production* operations within the storage facility are subject to AB 1420 regulations.

6. **Q**. My facility has some local gas company supplied gas piped to my heat treatment systems, power production operations, and flare pilot. Must these natural gas supply pipelines follow AB 1420 regulations?

A. No, pipelines with natural gas supplied by the local gas company are not subject to the AB 1420 regulations. Other State and local jurisdictions may have requirements.

§1760. Definitions

1. **Q.** How do I determine whether my pipeline is in or near a sensitive area?

A. Your facility or lease pipeline may be in a sensitive area based on three criteria, found in CCR § 1760(r). "Sensitive area" means any of the following:

1) An area containing a building intended for human occupancy, such as a residence, school, hospital, or business that is located within 300 feet of an active gas pipeline and that is not necessary to the operation of the pipeline. If even one such building exists within 300 feet of any point along the pipeline, at least a portion of the pipeline falls within a sensitive area. To determine distances, field measurements could be made with a walker wheel or laser measuring tool, or non-field measurements could be done using an adequately scaled map.

2) An area determined by the supervisor to present significant potential threat to life, health, property, or natural resources in the event of a leak from an active gas pipeline.

3) An area determined by the supervisor to have an active gas pipeline that has a history of chronic leaks.

In the case of criteria 2) and 3), the DOGGR Supervisor will determine the boundaries of a designated sensitive area on a case-by-case basis.

2. **Q.** What types of buildings or areas of human occupation do not trigger a sensitive area designation?

A. Buildings which are not intended for human occupancy are not considered "sensitive areas." For example, buildings designated as Utility and Miscellaneous (U) or Storage (S) per the California Building Code (Title 24 of CCR) may be exempt. Places where workers (not associated with oil and gas operations) or the public are present for less than 2,000 hours per year may also be exempt. Agricultural fields, for example, are not considered sensitive areas. However, operators with questions about their sensitive area designation should consult DOGGR for confirmation.

3. **Q.** How are "environmentally sensitive" areas different from "sensitive" areas?

A. The "environmentally sensitive" designation in CCR § 1760(f) considers all oil or gas production facilities and their proximity to areas of human occupancy or environmental sensitivity. The "sensitive area" definition is narrower, and considers only the proximity of *active gas pipelines* to areas of human occupancy, or other areas as designated by the DOGGR Supervisor. Some areas may be designated both "environmentally sensitive" and a "sensitive area" due to their proximity to occupied buildings. However, the "environmentally sensitive" designation considers proximity to sensitive plant and animal habitats, to bodies of water, and to coastal zones. These areas are not included in the definition of a "sensitive area."

4. **Q.** Why do the regulations have separate definitions for "environmentally sensitive" and "sensitive area"?

A. The effects of a gas release differ from those of an oil spill, and have different impacts on the surrounding area. The "sensitive area" distinction identifies receptors that are sensitive to the effects of a gas release. This definition was included in DOGGR's regulations to adequately address and prepare for this potential hazard.

4. **Q.** In §1760(k), the "gathering line" definition pertains only to pipelines that transport liquid hydrocarbons. Are gas gathering lines exempted from new DOGGR requirements?

A. No, active gas gathering lines would be considered an "active gas pipeline" as defined per §1760(s), and are subject to all DOGGR requirements for active gas pipelines.

6. **Q**. When is a flowline or gathering line considered an active gas pipeline?

A. Under the new regulations, a flowline or gathering line is considered an "active gas pipeline" when it meets the definition in CCR § 1760(a). "Active gas pipeline" means an in-service pipeline that carriers gas in gaseous or vapor phase and may contain fractional amounts of liquids, solids, and other non-hydrocarbon gases. Flowlines and gathering lines would be considered "active gas pipelines" if they are in-service and carry primarily gas. “In-service” CCR § 1760 (p) means any production facility that is capable of containing fluid safely and can be shown to operate as designed.

7. **Q**. What other pipelines at my facility may be considered “active gas pipelines” besides flowlines and gathering lines?

A. Two other types of pipelines that may be considered “active gas pipelines” are process pipelines and intra-facility pipelines that carry gas. Process pipelines, or “plant piping,” are the pipelines within a process facility or tank farm. Intra-facility pipelines are gas lines that enter or exit a facility, connecting to another facility or piece of production equipment. Some specific examples of process pipelines and intra-facility inlet and outlet pipelines are: a) tank and vessel vapor recovery lines, b) process lines to/from vessels, separators, and treatment units, or c) produced gas supply lines to a heater, steam generator, flare or electrical generation operation (e.g. micro-turbine).

§1774. Pipeline Construction and Maintenance

1. **Q.** Why is the Cal/OSHA regulation CCR § 6533 referenced in DOGGR’s regulations?

A. DOGGR included a reference to Cal/OSHA’s regulation to identify applicable standards in pipeline construction and maintenance. Operators should already be familiar and in compliance with Cal/OSHA’s requirements. Please contact Cal/OSHA for guidance on complying with their regulations.

§1774.1 Pipeline Inspection and Testing

Inspection

1. **Q.** CCR § 1774.1(b) now reads, “Operators shall inspect all active gas pipelines in sensitive areas that are 10 or more years old for leaks or other defects at least once a year, or at a frequency approved by the Supervisor and listed in the operator’s Pipeline Management Plan.” What kind of inspections are acceptable for active gas pipelines?

A. Two examples of leak inspection methods for active gas pipelines are: 1) Gas leak detection via hand held vapor analyzer, and 2) infrared photography or video. These methods can be used on both underground and aboveground pipelines. Visual inspection should be used for all aboveground sensitive gas pipelines to identify defects. Visual inspection following soapy film application is another valid method of inspecting aboveground pipelines for leaks.

2. **Q.** CCR § 1774.1(a) already requires operators to visually inspect all aboveground pipelines for leaks and corrosion at least once a year. Why were additional inspection requirements added for active gas pipelines in CCR § 1774.1(b)?

A. Additional requirements were added for active gas pipelines to improve public safety because: a) gas leaks are not always detectable with human senses, and b) buried active gas pipelines must also be leak tested. Inspection per §1774.1(a) pertains only to aboveground pipelines and is primarily for corrosion inspection of pipeline exterior, and for detection of liquid leaks.

3. **Q.** How does annual leak detection differ from the periodic mechanical integrity testing required by CCR § 1774.1(f)?

A. Mechanical integrity testing (MIT) must be conducted in one of four methods prescribed by regulation. MIT has a predictive aspect and verifies that a pipeline is fit for service until the next scheduled test. Leak detection testing does not include this predictive aspect, nor does it determine whether a pipeline is fit for continued service. Leak detection can only confirm leak status at the time of inspection or monitoring.

4. **Q.** My facility currently performs gas leak detection on a quarterly or annual basis at the production facility per South Coast Air Quality Management District Rule 1148.1 or 1173, or per California Air Resources Board SB 1371 requirements. Will this satisfy DOGGR's leak detection requirement?

A. Yes, but only if the gas leak detection that is performed for other agency requirements is enhanced to provide a comprehensive leakage survey along the entire run of aboveground and underground gas pipelines located in "sensitive areas."

Testing

1. **Q.** Why is periodic MIT now required for all active gas pipelines in sensitive areas, when AB 1420 only addresses active gas pipelines that are four inches or less in diameter?

A. DOGGR regulation CCR § 1774.1(f) has been expanded to ensure MIT is completed on all active gas pipelines near sensitive receptors. Previously, MIT was only required for those pipelines greater than 4" in diameter located in "urban areas," and all "active environmentally sensitive pipelines that are gathering lines." However, the regulation left open the possibility that active gas pipelines near sensitive receptors would go untested because they were not in a location deemed "environmentally sensitive" or populous enough to be considered an "urban area." The expanded regulation ensures that active gas pipelines of any size that are located near sensitive receptors are tested regularly. This expansion of the MIT requirements for active gas pipelines is within DOGGR's authority under PRC § 3106 and 3270.

2. **Q.** Will I have to perform MIT on all active gas pipelines located in sensitive areas immediately after this regulation becomes effective?

A. No. For pipelines that are subject to MIT under the new regulations, but were not subject to MIT previously, MIT is not required to be completed until January 2, 2020. However, current operators must submit a revised Pipeline Management Plan (PMP) to DOGGR by October 1, 2019. The revised PMP must include a testing method and schedule, among other things listed in CCR § 1774.2(b).

3. **Q.** I have some gas gathering lines that are regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA). Are PHSMA-regulated pipelines subject to the new DOGGR pipeline regulations?

A. If the gathering lines are located within an oil and gas field, they fall within DOGGR's administrative boundaries and are subject to DOGGR's regulations. The operator must comply with both PHMSA's regulations and DOGGR's new regulations. Some PHMSA requirements may satisfy DOGGR's regulatory requirements, and DOGGR will consider accepting operator's PHMSA compliance data on a case-by-case basis. Please see 49 CFR 192 for all of PHMSA's existing regulations.

4. **Q.** The gas separation operations at my facility appear to be located within a sensitive area. Does all gas process piping located within a sensitive area now require periodic MIT?

A. Gas process piping greater than 1" nominal diameter meets the definition of "pipeline" per CCR § 1760(m). If this process piping also meets the definition of "active gas pipeline" per CCR § 1760(a), and is located in a sensitive area, it is subject to periodic MIT. MIT must be conducted in one of four methods prescribed by regulation; these methods are listed at CCR § 1774.1(f). For example, the operator can conduct nondestructive testing using ultrasonic or other techniques approved by the DOGGR Supervisor, to determine wall thickness. Process piping associated with skid-mounted equipment and located within sensitive areas, is part of the production facility and is subject to periodic testing.

5. **Q.** Why was the retention period for MIT results increased from 5 years to 10 years?

A. Operators may conduct MIT at an alternative frequency than every two years with the approval of the DOGGR Supervisor. Testing is also not required on pipelines which are not currently active. DOGGR increased the retention period for MIT results so that a pipeline will have at least two test records retained on file. Corrosion rates are established using at least two test cycle measurements.

6. **Q.** DOGGR added new language to CCR § 1774.1(f) which reads, "The operator shall assess all test results to determine continued safe operations and that risks identified in the Pipeline Management Plan (PMP) are adequately addressed." What conditions may elevate the risks identified in the PMP?

A. Risk is inherent to such things as a pipeline's environment, product characteristics, condition, operation, and proximity to receptors. The operator should be monitoring changes, such as but not limited to increased pipeline corrosion rates, pipeline coating degradation, changes in production fluid chemistry, effectiveness of cathodic protection, or newly constructed nearby buildings. Changes in these conditions that increase risk should be addressed by the operator.

7. **Q.** CCR § 1774.1(f)(2) now includes pressure testing instead of hydrostatic testing. Why was the terminology changed?

A. The terminology was changed to broaden the description of testing methods available to operators. Hydrostatic testing is a type of pressure testing. Pneumatic pressure testing is now also permitted under the updated regulation.

8. **Q**. The stored energy of a compressed gas is hazardous if there were to be a pipeline failure during a pneumatic pressure test. Why does DOGGR allow pneumatic pressure testing?

A. DOGGR permits pneumatic pressure testing performed according to industry standards, with guidance from the entities listed in CCR § 1774.1(f)(2)(A) and (B). The referenced standards and entities provide guidance on performing pneumatic pressure testing, following stringent pressure limits, with safety planning and execution. If an operator elects to perform pneumatic pressure testing to satisfy their MIT testing requirement, the safe execution of the testing is the operator's responsibility. This type of pressure testing may be beneficial to operators of gas pipelines, where drying pipelines following a hydrotest is problematic.

9. **Q**. What are some examples of industry standards and methods for pressure testing oil and gas pipelines?

A. Some examples of industry standards and methods for pressure testing oil and gas pipelines are listed below:

- American Petroleum Institute (API) RP 1110, "Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas…",

- The American Society of Mechanical Engineers (ASME) B31.3, “Process Piping”
- ASME B31.4, “Pipeline Transportation Systems for Liquids and Slurries”
- ASME B31.8, “Gas Transmission and Distribution Piping Systems”
- ASME PCC-2,” Repair of Pressure Equipment and Piping”
- American Society for Testing and Materials (ASTM) F2164-18, “Standard Practice for Field Leak Testing of Polyethylene (PE) and Crosslinked Polyethylene (PEX) Pressure Piping Systems Using Hydrostatic Pressure”
- 49 CFR 192, “Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards”
- 49 CFR 195, “Transportation of Hazardous Liquids by Pipeline”

10. **Q.** At our facility, we follow the pipeline testing and inspection standards of Cal/OSHA regulation CCR § 6533. Would this substitute for the MIT required in DOGGR’s regulation CCR § 1774.1(f)?

A. The CCR § 6533 pipeline testing and inspection standards may satisfy DOGGR’s MIT requirements, if the testing is done every two years, subject to the approval of the DOGGR Supervisor.

11. **Q**. For a test method requiring prior DOGGR Supervisor approval, how do I get approval?

A. Send a written request to the District Deputy at your local District DOGGR office. In the letter, include a detailed description of the pipeline undergoing test (e.g. pipeline identification, test segment boundaries, above or below ground, etc.) and explain why the chosen test method is appropriate (e.g. a guided wave test pre-assessment shows test objectives can be achieved). Then wait for a confirming response back from DOGGR before performing the test.

12. **Q**. Are my gas gathering lines in sensitive areas that operate at less than 0 psig, exempted from testing?

A. Gathering lines located in sensitive areas that operate at less than 0 psig, are exempt from testing if they meet the same criteria for vapor recovery piping exemption. Per §1774.1(g) vapor recovery piping are exempt from testing under §1774.1(f) if they are equipped with safeguards and are leak tested at least annually. An example of safeguards are installed oxygen sensors that detect a leak of atmospheric air into the system before the compressor is affected by the leak. These sensors should be continuously monitored and alarmed to be an effective safeguard.

13. **Q.** I am performing MIT using ultrasonic testing in accordance with API 570 “Piping Inspection Code,” with Supervisor approval per CCR 1774.1(f)(1). If wall loss is detected in some areas and is below the minimum replacement thickness, is this a failed test? Do I have to take my pipeline out of service and notify DOGGR in writing?

A. If engineering analysis is not promptly performed on the areas with wall loss below minimum replacement thickness, it is a failed test. The pipeline shall be promptly designated out-of-service and DOGGR shall be notified in writing. If engineering analysis is performed promptly after detecting wall loss below minimum replacement thickness, the pipeline can remain in-service pending the results of the engineering analysis.

The engineering analysis should be performed by a qualified engineer. Two examples of industry manuals the engineer could follow in performing the analysis are ASME B31G, “Manual for Determining the Remaining Strength of Corroded Pipelines,” and AP 579, “Fitness for Service.” If results show the pipeline is fit-for-service until the next test required by DOGGR, then the pipeline can continue to remain in-service and shall be re-evaluated during the next test cycle. If analysis results show the pipeline is not fit-for-service until the next required test, then it is a failed test. The pipeline shall be removed from service, pending possible repair/replacement, and DOGGR shall be notified in writing.

14. **Q.** If I don’t currently own a particular testing standard that I would consider using, will DOGGR provide a copy to me?

A. No, although DOGGR has copies of the common testing standards, copywrite laws prevent DOGGR from providing a copy to operators. Testing standards that an operator chooses to use should be obtained or purchased by the operator. An excellent reference that contains much of the information and the federal standards is the “Pressure Testing Requirements for Hazardous Liquid Pipelines in California” that is available for free on the Office of the State Fire Marshal Pipeline Safety Division ‘s website.

§1774.2 Pipeline Management Plans

1. **Q**. Does my facility have to report on all gas pipelines listed in the PMP and aspects of integrity management carried out for another agency’s compliance requirement?

A. Yes. The operator shall prepare a PMP for all pipelines, per CCR § 1774.2(a). The PMP should include a testing schedule and testing method for all pipelines, even when the testing is performed to meet the requirements of another agency, like PHMSA or Cal/OSHA. Including this schedule allows the operator to document that pipeline integrity is comprehensively managed. This documentation may also demonstrate how compliance with another agency's requirements meets DOGGR's testing and reporting requirements.

3. **Q**. Products at our facility include crude oil, natural gas, and produced water. Is this general description satisfactory for a product list per CCR § 1774.2(b)(5)?

A. Maybe, however if the fluid stream also contains other significant components like hydrogen sulfide, then those components also need to be documented. CCR § 1774.2(b)(5) requires a description of the product transferred in each pipeline.

4. **Q.** Why do I now need to describe preventative maintenance for associated appurtenances, instrumentation and equipment?

A. This description of preventative maintenance is required in CCR § 1774.2(b)(3) to ensure safe pipeline operations. Properly maintained equipment reduces mechanical/electrical failure and decreases human error, minimizing abnormal process conditions that could lead to loss of containment, fire, or injury. The operator's minimum requirement is to provide a description of the preventative maintenance planned for this equipment. Information included in the pipeline management plan allows DOGGR to verify that the operator is performing preventative maintenance on associated appurtenances, instrumentation and equipment. Examples of equipment related to pipeline operations include valves, actuators, gauges, and sensors.

5. **Q.** For all pipelines, CCR § 1774.2(b)(5) requires, "A description of the products transferred in each pipeline". Does this description include whether a pipeline has hydrogen sulfide in the fluid stream? At what levels in the fluid stream?

A. Yes, if hydrogen sulfide is contained within the fluid stream, then the presence of hydrogen sulfide must be identified as a product transferred in that pipeline. Noting the presence of "trace amounts" of hydrogen sulfide is sufficient to meet the requirement of the regulation. Other toxic or corrosive contaminants should also be identified.

6. **Q.** What type of software do I need to use the optional downloadable DOGGR PMP template?

A. The template was created using Microsoft Excel, but other spreadsheet software (such as Google Sheets), can be used to convert and edit the PMP template. DOGGR encourages operators to use Microsoft Excel to fill out the template. If you choose to use another software program, please convert the template back to Excel prior to submission.

A final option for an operator that does not have access to Microsoft Excel: 1) Print the two worksheets and enter the information by hand, or 2) If requested, DOGGR will mail the operator a printed copy of the template so the operator can enter information by hand on paper copies.

§1774.X Active Gas Pipeline GIS Mapping Requirements

Note: DOGGR requirements for GIS mapping were not included in the new AB 1420 regulations which became effective October 1, 2018. Rulemaking to address this topic is anticipated to start in 2019. As part of rulemaking, a workshop will be held to get input and feedback from operators regarding the draft regulations, data specifications, and submission procedures. Further questions and answers will be developed and added here following this workshop. Among the topics to be addressed will be acceptable formats for GIS mapping of active gas pipelines in sensitive areas.