August 22, 2016

Email submittal

Tim Shular
Department of Conservation
801 K Street, MS 24-02
Sacramento, CA 95814

Re: INGAA's Comments on the Discussion Draft of Underground Gas Storage Regulations

Mr. Shular:

The Interstate Natural Gas Association of America (INGAA), a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America, respectfully submits these comments in response to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) "Discussion Draft Underground Gas Storage Regulations" (Proposed Rule). The Proposed Rule was released July 8, 2016, and INGAA welcomes the opportunity to provide comments.

Natural gas provides 25 percent of the basic energy needs in the United States. INGAA's members represent the vast majority of the interstate natural gas transmission pipeline companies in the United States, including two in California. INGAA's members operate approximately 200,000 miles of pipelines and many underground natural gas storage facilities, and serve as an indispensable link between natural gas producers and consumers. The North American natural gas pipeline system is an energy highway that is the envy of the world. Natural gas storage is essential to providing reliable gas deliveries and pricing throughout seasonal and daily demand fluctuations, electrical grid shutdowns and maintenance, and natural disasters. INGAA and its members have a long history of working collaboratively with a variety of stakeholders on regulatory standards for natural gas pipelines and storage facilities, including the U.S. DOT (PHMSA) and State agencies. INGAA appreciates your consideration of these comments. Please contact me at 202-216-5930 or tboss@ingaa.org if you have any questions.

Sincerely,

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INGAA COMMENTS ON DOGGR PROPOSED RULE, “DISCUSSION DRAFT UNDERGROUND GAS STORAGE REGULATIONS”

California Code of Regulations, Title 14, Division 2, Chapter 4, Subchapter 1 Onshore Well Regulations

PROPOSED REGULATION ORDER

Article 4. Requirements for Underground Gas Storage Projects

August 22, 2016

The Interstate Natural Gas Association of America (INGAA) appreciates the opportunity to submit these comments in response to the Division of Oil, Gas, and Geothermal Resources (DOGGR) "Discussion Draft Underground Gas Storage Regulations" (Proposed Rule). INGAA supports DOGGR's goal to clarify well construction, testing, monitoring, data collection, and emergency response standards to ensure safe operations. An overview of INGAA comments and recommendations includes:

1. It is premature for DOGGR to implement minimum safety standards for natural gas storage facilities until recommendations from the Aliso Canyon natural gas task force and Federal minimum standards are issued, per the PIPES Act of 2016. In the interim, INGAA recommends DOGGR adopt recently developed consensus standard API RP 1171 by reference.

2. INGAA supports DOGGR's use of a risk-based approach for assessing existing wells and designing new wells, determining appropriateness of safety valves, monitoring/evaluating corrosion, and verifying integrity of wells and reservoirs. DOGGR should remove overly-prescriptive requirements, which contradict DOGGR's risk-based approach. If DOGGR intends to retain prescriptive requirements, DOGGR should request that the Department of Energy (DOE) conduct studies through the National Labs to confirm actual effectiveness of the required equipment, relative to other alternatives.

3. The DOGGR Proposed Rule references California Air Resource Board (ARB) proposed natural gas storage facility monitoring requirements that are not feasible based on currently proven technologies. ARB's economic analysis also does not adequately estimate the costs and benefits of the proposed monitoring requirements. INGAA recommends DOGGR remove the reference to ARB's inspection and leak detection protocol and instead allow operators to submit an inspection and leak detection protocol based on API RP 1171.

4. DOGGR should allow one year for operators to create and submit Risk Management Plans. Operators should be permitted to include timelines for bringing existing wells/facilities into conformance with construction, integrity testing, monitoring, and data submission requirements in their Risk Management Plans.

Detailed comments follow.

Detailed Comments

1. It is premature for DOGGR to implement minimum safety standards for natural gas storage facilities until recommendations from the Aliso Canyon natural gas task force and Federal minimum standards are issued, per the PIPES Act of 2016. In the interim, INGAA recommends DOGGR adopt recently developed consensus standard API RP 1171 by reference.

Planned Federal Regulations and Consensus Standards Can Address Storage Field Concerns

On June 22nd 2016, President Obama signed federal legislation, the PIPES Act of 2016.[1] Section 12 of the PIPES Act requires the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue safety standards for underground storage facilities within 2 years. The Act states that "The Secretary *may* authorize a State authority (including a municipality) to participate in the oversight of underground natural gas storage facilities … A State authority may adopt additional or more stringent standards for intrastate underground natural gas storage facilities ***if** such standards are compatible with the minimum standards prescribed under this section.*"[2] The Act also requires PHMSA to take into consideration the recommendations of the Aliso Canyon natural gas leak task force in developing minimum safety standards for underground natural gas storage facilities. Specifically, the task force must: (i) analyze and develop conclusions regarding the cause and contributing factors of the recent Aliso Canyon natural gas leak, (ii) analyze the measures taken to stop the leak and alternatives that could have been used instead, (iii) develop an assessment of the impacts of the leak on health, safety and the environment, and (iv) analyze how local, State and Federal agencies responded to the incident. Congress provided the task force with up to 180 days – or December 19, 2016 – to prepare a report summarizing its findings on these issues. The deadline to form this task force was just last month (July 7, 2016). Given that PHMSA has yet to issue Federal minimum standards for natural gas storage wells and the Aliso Canyon task force has yet to issue a final report summarizing its findings and recommendations, it is premature for DOGGR to propose these prescriptive minimum safety standards.

Prior to the Aliso Canyon natural gas leak, INGAA and others undertook an effort to develop a consensus standard that provide guidance to operators on how to design, operate, and ensure the integrity of underground natural gas storage. Along with INGAA, trade associations that address all segments of the natural gas industry, including the American Petroleum Institute (API) and American Gas Association (AGA), as well as regulators (PHMSA, FERC, and State Authorities), participated in an effort to develop consensus practices and standards. This culminated in the release of two recommended practices (RP) accredited by the American National Standards Institute (ANSI). API RP 1171[3] (September 2015) addresses storage in depleted hydrocarbon reservoirs and aquifer reservoirs, which comprise the vast majority of storage fields including

[1] Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016, Pub. L. No. 114-183 (June 22, 2016) (codified as U.S.C. § 60141).
[2] *Id.* Emphasis added.
[3] Summary – API Recommended Practice 1171©, http://www.api.org/~/media/files/publications/whats%20new/1171_e1%20pa.pdf .

Aliso Canyon and all the other California storage fields. API RP 1170[4] (July 2015) addresses storage in salt caverns. Trade association members have committed to these practices through board resolutions, and the individual companies are modifying their existing integrity practices to be in conformance with these standards.

The new consensus standards and recent, planned, and potential new federal regulations provide platforms to address storage field integrity, safety, and environmental concerns. INGAA recommends DOGGR adopt API RP 1171 by reference at this time, and avoid adopting additional, prescriptive standards until the Aliso Canyon task force has issued its final report, and PHMSA has issued Federal minimum safety standards.

2. **INGAA supports DOGGR's use of a risk-based approach for assessing existing wells and designing new wells, determining appropriateness of safety valves, monitoring/evaluating corrosion, and verifying integrity of wells and reservoirs. DOGGR should remove overly-prescriptive requirements, which contradict DOGGR's risk-based approach. If DOGGR intends to retain prescriptive requirements, DOGGR should request that the Department of Energy (DOE) conduct studies through the National Labs to confirm actual effectiveness of the required equipment, relative to other alternatives.**

<u>INGAA Supports DOGGR's Proposed Risked-Based Approach</u>

INGAA recognizes that DOGGR references concepts and language from API RP 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" throughout DOGGR's Proposed Rule. INGAA commends DOGGR for incorporating elements of this consensus standard into its Proposed Rule. The risk-based approach to well integrity management advocated in API 1171 includes five steps: 1) Data Collection, Documentation, and Review, 2) Hazard and Threat Identification, 3) Risk Assessment, 4) Risk Treatment – Developing Preventative and Mitigative Measures, and 5) Periodic Review and Reassessment. Recognizing that well integrity data verification and assessment must be done for every storage well in order to effectively apply the management practices in API 1171, operators are working towards uniform application of the standard. INGAA supports the concept of setting performance standards for natural gas storage wells and developing a Risk Management Plan focused on attaining these standards, so that resources are expended in a timely and efficient manner on the wells that present the highest risk.

<u>Prescriptive Construction Standards Should Be Reduced; Risk Management Plans and Performance Standards Appropriately Direct Operators' Focus</u>

Pipeline operators and regulators have moved toward the Integrity Management model: using a data-driven risk management process to guide decision-making on the selection of preventative and mitigative measures and task frequency. Integrity Management began with pipeline systems as a pilot project in the late 1990's and culminated with PHMSA's issuance of Subpart O in

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[4] Summary – API Recommended Practice 1170©, http://www.api.org/~/media/files/publications/whats%20new/1170_e1%20pa.pdf .

2003. API RP 1170 & 1171 apply the established practice of utilizing a risk-based approach to the integrity management of storage wells.

Despite incorporating elements of API RP 1171's risk-based approach in the Proposed Rule, DOGGR's proposed Well Construction and Mechanical Integrity Testing requirements are overly-prescriptive. The prescriptive construction and integrity testing requirements proposed by DOGGR "turn the clock back" on the risk-based approach that has progressed for the last decade. This limits the efficient use of operators' integrity management "toolbox" to effectively respond to their risk assessments and achieve performance standards. A risk-based approach drives operators to first address wells that present the highest risk; applying DOGGR's numerous prescriptive requirements to all wells contradicts DOGGR's risk assessment approach and will require operators to spread resources and divert focus away from higher-risk wells. Despite the Aliso Canyon leak in 2015, integrity incidents at storage wells are historically "very unlikely" (using the Center for Chemical Process Safety standard, a range of 1E-05 to .99E-03 incidents per well-year), even with the regulations or consensus standards that existed prior to API RP 1170/1171.[5] Therefore, applying the multitude of prescriptive requirements that DOGGR has proposed to all storage wells, regardless of risk assessment, will likely increase cost and decrease gas availability/reliability for consumers, as storage wells may be substantially more challenging to operate. INGAA believes DOGGR should adopt API RP 1171 by reference at this time and avoid adopting additional, prescriptive standards. Once the Aliso Canyon task force has issued its final report and PHMSA has issued Federal minimum safety standards, DOGGR can then compare those with API RP 1171 and identify and address perceived shortcomings, if any. If DOGGR retains additional construction and testing requirements above API RP 1171 in the Final Rule, INGAA recommends changes to the Proposed Rule, as outlined below.

DOGGR establishes a reasonable performance standard in proposed §1726.5(a): "Operators shall design, construct, and maintain gas storage wells to effectively ensure mechanical integrity under anticipate operating conditions for the underground gas storage project. The operator shall ensure that a single point of failure does not pose an immediate threat of loss of control of fluids and make certain integrity concerns with a gas storage well are identified and addressed before they can become a threat to life, health, property, or natural resource." Then, in proposed §1726.5(b), DOGGR presents an extensive list of primary and secondary mechanical barriers, all of which are required in order for the well to achieve the performance standard outlined in §1726.5(a).

Required primary mechanical barriers include tubing and packer equipment. The majority of natural gas storage wells in the United States (75% or more) do not include tubing and packer set-ups.[6] Installing tubing and packer equipment on storage wells that currently flow through production casing only will create performance, safety, operability, and economic burdens, without necessarily reducing risk. Installing tubing restricts the flow capacity through a well, which may require drilling of additional wells to meet current injection/withdrawal obligations. On a national basis, widespread installation of tubing in storage wells would result in a reliability replacement demand equivalent to a five percent (5%) to twenty-five percent (25%) increase in

[5] "Underground Natural Gas Storage, Integrity & Safe Operations" (July 6, 2016), https://www.regulations.gov/document?D=PHMSA-2016-0023-0002 .
[6] "Underground Natural Gas Storage, Integrity & Safe Operations, Appendix 6" (July 6, 2016), https://www.regulations.gov/document?D=PHMSA-2016-0023-0002 .

the number of storage wells.[7] In this case, drilling more wells could increase exposure to storage well incidents, without necessarily reducing the likelihood or consequence of an individual incident, and without increasing gas availability/reliability for consumers. Adding tubing to a well also adds potential leak points; for example, installing 30-foot joint tubing in a well 8000 feet deep adds 269 potential leak points (each screwed connection is a potential leak point). As one example, without a tubing and packer set-up, cementing behind the production casing and assuring a good quality cement bond with the adjacent intermediate or surface casing (another prescriptive requirement of proposed §1726.5(b)), would also assure that "a single point of failure does not pose an immediate threat of loss of control fluids…" An additional approach that could achieve the performance standard in proposed §1726.5(a) without a tubing on packer completion could be a "slim hole" or "tubingless" completion installed within the original casing. In this example, a cemented liner provides a barrier in addition to the original casing. The Final Rule should encourage operators to select the equipment and processes, from a variety of available options, that most efficiently mitigate risk.

In one exception to the otherwise prescriptive primary and secondary barriers required in §1726.5(b), the Proposed Rule adopts language from API RP 1171 Section 6.2.5 and establishes a risk-based approach to evaluating the appropriateness of automatic or remote-actuated safety valves (§1726.3(a)(2)). INGAA supports DOGGR's proposed risk-based approach to determining safety valve requirements, as it acknowledges the many potential safety and environmental impacts of installing various types of emergency shutdown valves. As the Proposed Rule acknowledges, potential safety benefits include limiting the magnitude, duration, and consequence of an event, particularly in damage-prone or sensitive areas. At the same time, the Proposed Rule acknowledges that disadvantages of emergency shutdown valves include increased risk to workers and the public due to increased well servicing rates and related loss-of-containment potential, and increased challenges with emergency intervention operations.[8] DOGGR's recognition of the pros and cons of emergency shutdown valves is no different than the pros and cons of tubing and packer completions. INGAA urges DOGGER to recognize this similarity and permit operators to use the same risk base decision making process on the applicability of tubing and packers as for emergency shutdown valves. Entering existing wells to install tubing and packers raises many of the same safety and environmental concerns as installing a subsurface safety valve. INGAA contends that a "one size fits all" approach is not effective in minimizing safety and environmental impacts of natural gas storage, and therefore supports DOGGR's proposed risk-based approach to determining safety valve requirements. This approach should be extended to other proposed construction requirements.

DOGGR establishes a performance standard in proposed §1726.5(a). DOGGR should eliminate the overly-prescriptive requirements in proposed §1726.5(b), in favor of requiring operators to submit API RP 1171-compliant Risk Management Plans to meet the performance standard proposed in §1726.5(a), as required by proposed §1726.3. INGAA commends DOGGR for including §1726.5(c) in the Proposed Rule; this is essential to the Proposed Rule as written, because it allows the operator some opportunity to present an alternative design and construction method to DOGGR that is compliant with §1726.5(a). The prescriptive requirements in proposed §1726.5(b) are not necessary to achieve DOGGR's performance standard, and should

[7] Underground Natural Gas Storage, Integrity & Safe Operations, Appendix 6" (July 6, 2016), https://www.regulations.gov/document?D=PHMSA-2016-0023-0002 .
[8] *Id.*

be eliminated to allow operators full use of current and future production and control technologies to achieve the performance standard outlined in proposed §1726.5(a). If DOGGR intends to retain the prescriptive requirements listed in §1726.5(b), DOGGR should request that the Department of Energy (DOE) conduct studies through the National Labs to confirm actual effectiveness of the required equipment, relative to other alternatives. For example, the National Labs should evaluate the effectiveness of cemented, casing-only completions vs. tubing/packers, with respect to well integrity.

<u>Prescriptive Testing Standards Should Be Reduced; Risk Management Plans and Performance Standards Appropriately Direct Operators' Focus</u>

Similarly, the Proposed Rule requires very prescriptive and burdensome testing requirements in §1726.6, but in this case DOGGR provides no opportunity for operators to propose alternative testing procedures or intervals in their Risk Management Plan. Currently, operators establish logging frequencies using a risk management approach and based on historical integrity assessment data. Operators often log low-risk wells on a less frequent basis than higher risk wells. As a result, there are not enough logging tools currently available to conduct temperature and noise logs annually, or thickness inspections every two years, as required in the proposed §1726.6. By comparison, enhanced recovery and liquid hydrocarbon storage wells subject to federal regulations for the Underground Injection Control (UIC) program, established by the Safe Drinking Water Act (SDWA), are generally required to demonstrate mechanical integrity every five years.[9] DOGGR does not even provide a timeline or staggering for the conducting of initial assessments under this section; this would put safety, operability, and economic burdens on operators during the first year of the proposed rule, as all wells will have to be logged with an insufficient number of tools available in the market.

§1726.6(a)(3) requires a pressure test of at least as high as 115 percent of the maximum operating pressure. Periodic pressure tests at these elevated pressures expand the casing, potentially breaking down the bond between the cement and the casing, especially at the proposed frequency. INGAA recommends that casing testing and commissioning follow the recommended practices in API RP 1171, Section 6.9.1. Allowance must be made so that the pressure on the tubular and packer at the base of the well does not exceed the design pressure; 115% of MAOP at the surface represents a much higher pressure at the bottom of the well.

There are important safety and service reliability impacts of the proposed testing frequency. Well equipment, including tubing and packers and subsurface safety valves, may have to be removed (where present) to facilitate much of the required integrity testing. Equipment inside the well casing impedes entry and exit of analytical tools, impeding the operator's ability to employ analytical tools (e.g., profile calipers) and run logging/detection programs.[10] Removing tubing, packers, safety valves, and other equipment, especially at the proposed frequency, poses a significant safety risk to employees, and runs the risk of damaging the equipment. Damage may not be apparent until the well is put back into service, creating a potential integrity issue. Pressure testing requires filling the well with treated water, which then must be disposed of. Filling the well with fluid, especially on a biennial basis, risks damaging the storage formation

[9] 40 C.F.R. §146.23

[10] "Underground Natural Gas Storage, Integrity & Safe Operations, Appendix 6" (July 6, 2016), https://www.regulations.gov/document?D=PHMSA-2016-0023-0002 .

and may require abandonment of the well and/or drilling a new well to replace the lost capacity. Some operators currently install new tubing when tubing is pulled, to reduce the risk of thread/collar leak when re-coupling the previously-installed tubing (this risk is created only by uninstalling and reinstalling existing tubing). Installing the new tubing could cost $100,000 – $750,000 each occurrence, varying greatly based on the depth of the well. Furthermore, removal and reinstallation of this equipment adds days to the downtime associated with the proposed testing regime, potentially impacting reliability and availability of gas for customers, especially during peak demand. With over 400 natural gas storage wells in California, the proposed testing frequency has the potential to drastically impact employee safety, gas reliability, and operating cost of natural gas storage wells in California.

INGAA recommends that DOGGR adopt API RP 1171 by reference, including the risk assessment and integrity testing requirements outlined in this consensus standard. If DOGGR elects to issue more prescriptive requirements, DOGGR should require a risk and performance-based approach to the Mechanical Integrity Testing requirements prescribed in proposed §1726.6. Similar to proposed §1726.5(a), DOGGR should establish performance criteria for baseline temperature, noise, thickness, and pressure test results. Operators will then conduct baseline temperature, noise, thickness, and pressure testing at a frequency defined in their Risk Management Plan to establish well condition. This will reduce the burden associated with limited commercial availability of logging tools. Companies will then establish reassessment intervals based on risk assessments of the baseline testing, using processes outlined in their Risk Management Plans. This process will assure maximum effectiveness of integrity testing by scaling operators' resources and focus based on actual risk to life, health, property, or natural resources.

3. **The DOGGR Proposed Rule references California Air Resource Board (ARB) proposed natural gas storage facility monitoring requirements that are not feasible based on currently proven technologies. ARB's economic analysis also does not adequately estimate the costs and benefits of the proposed monitoring requirements. INGAA recommends DOGGR remove the reference to ARB's inspection and leak detection protocol and instead allow operators to submit an inspection and leak detection protocol based on recently developed consensus standards (API RP 1170 and API RP 1171).**

ARB's Proposed Continuous Monitoring Technology is Not Proven

Referencing inspection and leak detection protocol, in proposed §1726.5(e), "The requirements of this subdivision shall cease to apply if the California Air Resources Board adopt and implement regulations with the same or stricter requirements." ARB has proposed stricter requirements[11] and INGAA provided feedback on ARB's proposed requirements during the Public Comment period.[12] The following comments with respect to DOGGR's Proposed Rule are similar to those that INGAA provided to ARB.

[11] "Appendix A: Proposed Regulation Order" (May 31, 2016), http://www.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm .

[12] "INGAA's Comments on the CARB Proposed Regulation for Greenhouse Gas Emissions Standards for Oil and Natural Gas Facilities" (July 18, 2016), http://www.ingaa.org/Filings/RegulatoryFilings/29949.aspx .

The continuous monitoring technology for storage facility monitoring required by ARB in proposed §95668(i)(1)(A) and (C) is not proven, because these provisions primarily rely upon the use of optical gas imaging (OGI), which is a periodic screening device used to *qualitatively* identify leaking components. OGI does not quantify leak volumes or leak rates. Proposed §95668(i)(1)(A) – (C) provides a list of three monitoring requirements. The requirements include: (A) Continuous monitoring of the ambient air. (B) Daily screening of each storage wellhead assembly and surrounding area within 200 feet of the wellhead; or (C) Continuous monitoring of each storage wellhead assembly and surrounding area within 200 feet of the wellhead. ARB background documents (e.g., Economic Analysis cost estimates) imply that ARB intends for condition (A) to apply, plus either (B) or (C). There are technological issues associated with the continuous monitoring proposed in subsections (A) and (C). A comment below also reviews the economic analysis for these three options, including the daily "manual inspection" option in subsection (B). Cost considerations are superseded by the technological issues.

ARB's Economic Analysis and other support documents provide minimal detail on the automated monitoring technologies considered by ARB, and the cost estimates are based on either (1) applying optical gas imaging (OGI) with costs apparently based on presumed costs for infrared (IR) camera, such as the FLIR camera or (2) a combination of unspecified ultrasonic monitors and IR detectors. Thus, it appears ARB anticipates OGI would be used in a continuous operating mode. While INGAA members have used OGI for periodic leak surveys, INGAA does not believe that commercial technologies are available for continuous monitoring. This perspective is supported by the U.S. Department of Energy (DOE), which launched a program to address this technology gap, as discussed below.

Although vendors are attempting to adapt OGI for continuous operation, its market entry and use to date for methane detection is as a hand-held camera for short term field tests rather than continuous operation. OGI functionality provides leak *detection*, but does not quantify leak rates or provide quantitative assessments such as changes from a baseline level, which is a performance metric in the Proposed Rule. ARB background documents also indicate ultrasonic meters could be used for monitoring. There is no detail on such technology, commercial products, or its application. INGAA does not agree with ARB conclusions that such technology is available to meet rule requirements.

ARB improperly assumes the availability of a commercial system for fixed mounted leak detection that requires little or no user intervention. For methane detection, OGI is currently used as a hand-held instrument requiring human interface for leak determination. This technology has not been commercially implemented at compressor stations or storage fields for the purpose of autonomous ambient monitoring or for leak detection. FLIR, the leading OGI technology provider, has investigated gimbal mounted systems for use in fixed mount applications, but software, system integration, communication, audible and visual alarm or warning system development and integration still need to be tested and validated. Then, performance would need to be proven for the application and distances associated with storage wellheads and associated equipment. For such use, additional concerns would need to be addressed such as intrinsic safety requirements, labor from human intervention to investigate false positives, QA/QC criteria (e.g., calibrations, periodic audits) for continuous operation, and an alternative optics (e.g., telephoto lens) to allow storage wellhead surveying at greater distances.

In addition, ARB envisions monitoring that includes a performance metric requiring action when levels vary by more than 10% from a baseline. This monitoring paradigm is not established and is highly uncertain. It is unclear how such monitoring would be implemented for the two technologies noted by ARB – i.e., OGI or ultrasonic meters. For example, because methane is ubiquitous in the atmosphere from natural and anthropogenic sources, monitoring ambient methane levels would raise site-specific technical challenges that would differ for every storage field, such as: proximity to and prevalence of other methane sources (e.g., agricultural operations, wetlands); natural variability on an hourly, daily, and seasonable basis; wind direction and wind speeds; site topography; other meteorological effects; and surrounding area topography, buildings, and other physical features. In addition, maintenance and other operational activities could result in short term "deviations from a baseline" that actually result from standard and accepted practices. Thus, both operational and natural influences (e.g., natural diurnal affect depending on meteorology) clearly indicate that a "static" baseline is not appropriate, further complicating the ability to assess "performance." Developing the basis for establishing a "baseline," and inherent variability from "normal" scenarios, would likely become a complex research program, and months or years of monitoring would be required to understand the associated uncertainty and variability.

In addition to establishing a baseline, establishing an action level at a 10% deviation includes analogous complexities. OGI technology is not suited for assessing a quantitative change and has not been proven in that capacity. OGI *detects* methane but does not otherwise determine or quantify an associated measurable value. There are obvious and huge technical challenges in relying on OGI for the monitoring required by proposed §95668(i)(1)(A) or (C). It is also unclear how ultrasonic technology noted by ARB would be used in this capacity.

Technology gaps for methane monitoring have been acknowledged by the DOE, and DOE has launched an Advanced Research Projects Agency-Energy (ARPA-E) program: the ARPA-E Methane Observation Networks with Innovative Technology to Obtain Reductions (MONITOR) program. This program includes multiple research projects targeting development of monitoring envisioned by proposed §95668(i). DOE notes that MONITOR projects are

> …developing innovative technologies to cost-effectively and accurately locate and measure methane emissions associated with natural gas production. Such low-cost sensing systems are needed to reduce methane leaks anywhere from the wellpad to local distribution networks….[13]

This innovation is needed because:

> Existing methane monitoring devices have limited ability to cost-effectively, consistently, and precisely locate and quantify the rate of the leak.[14]

The ARPA-E MONITOR program includes six projects that would provide methane monitoring systems with continuous or near-continuous capabilities for sensing leaks and characterizing leak

[13] DOE ARPA-E website for MONITOR program, http://arpa-e.energy.gov/?q=arpa-e-programs/monitor.
[14] *Id.*

rates. Another five projects are investigating technologies that are even earlier in development where it is premature to research an integrated, functional system. The program was launched in 2015, and projects will include a demonstration phase if earlier phases meet performance objectives. The demonstration testing would occur in the third year. This national R&D program will not conduct the demonstration phase for about two more years. In addition, there are no assurances of success. Some of the projects employ OGI approaches, but it does not appear that ultrasonic monitoring implied by the ARB analysis is being assessed.

The DOE program is indicative of the current state of the science, and shows that technology is not available to address the monitoring envisioned by proposed §95668(i). Due to technological limitations, INGAA recommends DOGGR remove the reference to ARB's regulations in §1726.5(e).

ARB's Economic Analysis Should Be Revised and Benefits Should Be Estimated

The ARB Economic Analysis (EA) should be revised to address errors, omissions and questionable assumptions. The analysis does not estimate environmental benefits, and that estimation should be completed to justify the requirements. As discussed further below, recently developed consensus standards provide an avenue to managing storage field operations.

Storage well monitoring costs are included in Appendix B to the Staff Report, Initial Statement of Reasons. Appendix B is the ARB Economic Analysis (EA), and Section L, "Monitoring Plan," provides ARB estimates for the storage monitoring requirements. While ARB estimates benefits for other proposed standards, it does not estimate benefits from §95668(i). This oversight is significant because monitoring costs are substantial and have been under-estimated in the EA.

INGAA understands ARB's interest in storage field well leaks and the underlying intent of the proposed monitoring, but INGAA does not believe that §95668(i) would result in significant benefits. Qualitative leak monitoring programs, including OGI and audio-visual-olfactory inspections, are sufficient to detect leaks in a timely manner without the excessively burdensome, uncertain, and costly criteria proposed in this rule. At most, the proposed storage field Monitoring Plan may result in a brief reduction in the duration of a major incident leak and is unlikely to preclude such an incident.

The storage well monitoring costs in the EA include numerous errors, deficiencies, unsupported data, and inconsistencies. These flaws raise questions about the reliability of the cost-effectiveness analysis used to support the proposed storage facility monitoring requirements.

A detailed cost review of ARB's Economic Analysis (EA) is not provided here. But, INGAA is aware of a detailed review of ARB's estimated storage field monitoring costs prepared by Southern California Gas Company (SoCalGas) as a part of its comments to ARB.[15] INGAA supports the methodology and general conclusions of the SoCalGas review.

[15] "SoCalGas and SDG&E Comments on Proposed Regulation on Oil & Gas" (July 18, 2016) http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=oilandgas2016 .

The EA review completed by SoCalGas concludes that costs are under-estimated by a factor of 3 to 4.

The reasons that these costs have been under-estimated include:

- ARB reliance upon cost information from businesses that would profit from providing automated leak detection systems. No data or evidence is provided to document that systems have been successfully implemented for storage facility applications, and references for monitoring system costs were not provided.
- The EA includes *NO costs* for:
  - Operation and maintenance of automated wellhead monitoring systems;
  - Method 21 leak screening and subsequent leak repairs required by §95668(i)(4) and (5);
  - Contingencies for unproven technologies applications;
  - Data collection and alarm systems for notification of company and agency personnel;
  - Monitoring Plan preparation, and recordkeeping and reporting; and
  - Site and corporate support for survey teams (e.g., scheduling, leak repair).
- Based on experience with implementing OGI for more established hand-held leak surveys, costs are under-estimated for:
  - Capital cost of ambient monitoring equipment (e.g., including the number of monitors because multiple monitors would be required);
  - O&M costs associated with the ambient monitoring equipment;
  - OGI unit costs and the number of cameras required for wellhead monitoring to ensure camera availability and continuous compliance with the rule; and
  - Scenarios that erroneously conclude well groupings that allow the monitoring of multiple wells with a single instrument.
- The cost estimate assumes the monitoring systems have a ten-year lifetime, which is highly optimistic for sensitive instrumentation that has not been proven for continuous monitoring applications.

In addition, ARB has not considered the environmental, landowner, and permitting impacts of installing the ancillary infrastructure required to operate the proposed new monitoring technology. Storage wells traditionally have minimal, if any, power and communications infrastructure. Installation of overhead power/communications infrastructure to each facility and/or well to comply with §95668(i) represents a large amount of construction, including in previously undisturbed areas. The EA does not seem to recognize this; it appears wireless technology and/or underground burial is assumed. Additionally, "for purposes of the impact analysis, ARB assumes that compliance with the daily monitoring requirements will be achieved through installation of the grid detection system or through installation of wellhead sensors." As discussed, commercial systems are not currently available to support this assumption. The EA severely underestimates the initial cost of ancillary infrastructure (e.g., power, control, communications, security) associated with adding monitoring equipment to often-remote locations. The cost of this ancillary infrastructure will greatly surpass the $84,630 estimated in Appendix B of ARB's proposed rulemaking,

The review showed that the EA includes other deficiencies and flaws, such as arithmetic calculation errors (e.g., three on page B-53 alone) and conflicting cost assumptions (e.g., capital cost of monitoring equipment per well is listed as $54,000 in the text and $90,000 in the equation on page B-52).

In sum, the EA generally assumed that the monitoring equipment is purchased with no other transaction costs (i.e., installation, personnel training, troubleshooting, ongoing O&M). Collectively, these issues contribute to a significant under-estimate of costs. The SoCalGas review concluded that these costs are low and are off by a factor of 3 to 4. In addition to costs considered in the SoCalGas review, additional EA under-estimates are evident for power and communications infrastructure.

INGAA recommends that DOGGR allow operators to submit an inspection and leak detection protocol for approval that reflects API RP 1171 as part of operators' Risk Management Plan. INGAA recommends that DOGGR revise §1726.5(e) to read, in entirety:

> (e) The operator of an underground gas storage project shall adhere to an inspection and leak detection protocol that complies with API Recommended Practice 1171 and has been approved by the Division. The protocol shall include inspection of the wellhead assembly and attached pipelines for each of the gas storage wells used in association with the underground gas storage project, and surrounding area within a 100-foot radius of the wellhead of each of the wells used in an underground gas storage project. The operator's selection and usage of gas leak detection technology shall take into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology.

<u>If §95668(i) is Retained, Revisions are Warranted</u>

If DOGGR elects to retain prescriptive inspection and leak detection protocol requirements similar to ARB's proposed requirements, revisions are needed to address technical issues and implementation. As discussed above, there are technical challenges and cost implications associated with implementing the proposed rule monitoring provisions for underground storage facilities. If requirements are retained in the final rule, they should be revised to attempt to mitigate technical issues and develop a functional monitoring program with feasible criteria.

a. <u>Applicability of the three options in §95668(i)(1)(A) – (C)</u>

The applicability of the three "options" in §95668(i)(1)(A) – (C) should be clearly defined. Based on punctuation, (A) is a stand-alone sentence, and (B) and (C) are a list of two options. In addition, support documents imply that ARB anticipates item (A), plus (B) or (C) would be implemented. INGAA recommends requiring only one of the three options, as all of the options require extraordinary effort and, if functional, provide similar assurance. If technical challenges associated with continuous monitoring can be addressed, any of the three items would provide real time or daily data on site integrity and multiple requirements are not warranted.

With one of three options required, operators would have the ability to consider a near-term "manual" program based on item (B), while technology for continuous monitoring systems matures and becomes commercially available. Operators could opt to migrate from a manual process to more automated approach as warranted by technological advances. This approach would be similar to the requirements of DOGGR's current Emergency Rulemaking Action with respect to Underground Gas Storage Projects.[16]

b. Monitoring Schedule, baseline determination, and phased implementation

Although INGAA recommends the removal of continuous monitoring requirements for reasons stated earlier in this document, we discuss some additional considerations if continuous monitoring is required (i.e., §95668(a)(1)(A) plus (B) or (C) is required). Additional time and effort will be needed to identify and validate technologies that meet the Proposed Rule criteria, while fulfilling operator expectations for performance and reliability. As discussed above, an extended implementation period will likely be necessary to develop a monitoring "baseline" that considers site-specific variability and uncertainty. Additional time may also be needed to allow continuous monitoring technologies to mature.

DOGGR should consider a staged implementation approach that includes a design and testing phase prior to requiring compliance with performance objectives. This is necessary because developing a "baseline" and measuring deviations from that baseline will be fraught with uncertainty. This would result in compliance uncertainty, which is untenable for operators. As discussed above, there are many unknowns in understanding a baseline and perceived deviations, so an extended schedule is warranted to gather information and "test" this process. After implementation, operators would report on lessons learned and requirements could be revisited. Based on insights gained as monitoring data is collected, a plan could be developed for full implementation of monitoring requirements with defined performance metrics (e.g., comparison versus baselines values).

Without such an approach, continuous monitoring would surely face significant near-term technical challenges, and determining compliance could be complex. While INGAA supports transparency, prematurely implementing a monitoring approach would likely yield false positives and misinform the nearby community and public.

[16] California Code of Regulations §1724.9

4. DOGGR should allow one year for operators to create and submit Risk Management Plans. Operators should be permitted to include timelines for bringing existing wells/facilities into conformance with construction, integrity testing, monitoring, and data submission requirements in their Risk Management Plans.

Members of AGA, API, and INGAA collaborated on white paper titled "Underground Natural Gas Storage, Integrity and Safe Operations," which was presented at PHMSA's Public Workshop on Underground Natural Gas Storage Safety on July 14, 2016.[17] The paper contends "full conformance with API 1171 following a final rulemaking could take 7 – 10 years, taking into account the gap analysis currently underway to compare the new API 1171 to individual integrity management practices, and the development and implementation of risk assessment techniques applicable to an operator's specific storage fields, integrity management plans, inspection and maintenance practices, emergency management plans and storage well blowout contingency plans, and procedures for well and reservoir integrity tasks and activities (management of change, training and competency programs)." DOGGR's Proposed Rule includes more prescriptive and extensive construction, integrity testing, monitoring, and data submission requirements than AP RPI 1171. Per the proposed §1726.3(a)(1), "If the operator has storage wells that are not in conformance with the requirements of Section 1726.5, then the Risk Management Plan shall include a work plan for either bringing the wells into conformance or phasing the wells out of use." As written, §1726.3(a)(1) only applies to construction requirements. If DOGGR elects to retain the extensive, prescriptive requirements outlined in the Proposed Rule, the Final Rule should comprehend the extended timeline required for full conformance with all construction, integrity testing, monitoring, and data submission requirements. Obviously, bringing existing wells/facilities into conformance will take substantially more time and resources than applying the proposed requirements to new wells/facilities.

Furthermore, even assembling the Risk Management Plan in a comprehensive and cohesive manner will require extensive resources and coordination throughout many groups within operators' organizations. In the Emergency Regulations, DOGGR allowed operators six months to submit Risk Management Plans.[18] The Proposed Rule requires substantially more components within Risk Management Plans than the Emergency Regulations. As such, DOGGR should allow operators at least one year to submit Risk Management Plans from the effective date of the Final Rule.

The discussions earlier in this document around timelines for implementing integrity testing and monitoring requirements in the Proposed Rule provide examples supporting why the industry cannot "flip a switch" and become compliant with API RP 1171, let alone additional prescriptive requirements, overnight. Justification for a staggered timeline to implement integrity testing and monitoring requirements are detailed above. The proposed rule also requires operators to assemble and electronically submit a massive amount of data, calculations, charts, maps, and logs. Many, if not most, of these required items were previously not required to exist, let alone be organized into a single coherent and electronic format and transmitted to DOGGR. INGAA commends DOGGR for identifying in §1726.4(d) that it may not always be feasible to supply the

[17] "Underground Natural Gas Storage, Integrity & Safe Operations" (July 6, 2016), https://www.regulations.gov/document?D=PHMSA-2016-0023-0002 .
[18] California Code of Regulations §1724.9

data specified in §1726.4(a) and that "the Division may accept alternative data," but operators have concerns about what the burden of proof may be. Therefore, INGAA recommends that an additional subdivision be added to proposed §1726.3 and it reads:

> () If the operator has gas storage wells that are not in conformance with the project data, well construction, mechanical integrity testing, or monitoring requirements of this Article, then the Risk Management Plan shall include a work plan for either bringing the wells into conformance or phasing the wells out of use. The timeline for complete conformance with this Article should be outlined in the work plan.

DOGGR can expect conformance milestones to be achieved throughout the work plan period.

Additionally, the Proposed Rule does not establish a process or timeline for DOGGR to review, respond to, and approve an operator's Risk Management Plan (so that operators can begin implementing the plan). INGAA recommends that DOGGR clarify its proposed process and timeline, and solicit feedback from industry on this issue before final rulemaking.

5. General Comments and Clarifications

INGAA recommends the following additional changes to enhance the clarity and effectiveness of the Proposed Rule:

- The term "underground gas storage project" can be confusing. The term "project" in industry parlance generally refers only to new construction activities. INGAA recommends changing this term to "underground gas storage facility," which generally includes the connecting piping to the wells, storage compressors, dehydrators, filters, scrubbers, and meter equipment used to measure the gas flow into and out of the storage field.
- "Area of Review" is defined both as "surrounding areas that may be subject to the [reservoirs] influence" as well as "delineated by the geologic extent of the reservoir." This definition is internally inconsistent, and should be further clarified.
- §1726.4(a)(5)(F)(ii) states that wells that have been abandoned or inactive for more than two years shall have cement plugs. There are a number of reasons why wells may be temporarily inactive for more than two years; it is important to consider the reason the well was initially taken out of service (e.g. lack of gas demand, integrity issue, etc.). Plugging an existing well only to drill a new well could create more safety and environmental concerns than maintaining the existing well. INGAA recommends that operators perform a risk assessment when determining the most appropriate time frame to plug a well, which would be included as part of the Risk Management Plan.

Conclusion

Underground storage of natural gas is an essential component of the energy network, both in California and across the U.S. Natural gas storage is critical to providing reliable gas deliveries and pricing throughout seasonal and daily demand fluctuations, electrical grid shutdowns and maintenance, and natural disasters. Without storage, power generators, transmission and distribution system operators, industrial customers, and residential users would face potential supply shortages and highly variable pricing.

Because of the fundamental importance that underground natural gas storage plays in America's energy network, operators are always searching for new equipment, tests, and procedures to improve safety and reliability. As such, INGAA supports DOGGR's goal to clarify well construction, testing, monitoring, data collection, and emergency response standards to ensure safe operations. INGAA and trade associations that represent all segments of the natural gas industry, including API and AGA, have worked to develop API RP 1170 & 1171, consensus standards which provide guidance to operators on how to design, operate, and ensure the integrity of underground natural gas storage.

It is premature for DOGGR to implement minimum safety standards for natural gas storage facilities until recommendations from the Aliso Canyon natural gas task force and Federal minimum standards are issued, per the PIPES Act of 2016. In the interim, INGAA recommends that DOGGR adopt the recently developed consensus standards API RP 1171 by reference. This consensus standard represents a risk-based approach that guides operators on well design and construction, mechanical integrity testing, data collection, and monitoring. Each storage field is uniquely situated, and API RP 1171 acknowledges the variety of geography, geology, surface use, depth, and many other site-specific factors that must be taken into consideration when designing a facility's Risk Management Plan. API RP 1171 also incorporates considerations for the equally important non-facility aspects of integrity management, for example: employee training, testing, documentation, procedures, periodic reviews, and continual improvement. Incorporating these standards by reference, instead of setting prescriptive requirements, will allow operators to assemble Risk Management Plans and select from an appropriate range of tools to address the risks identified through assessments of specific wells. This approach will also encourage innovation of new tools and processes to meet operators' Preventative and Mitigative obligations, as outlined in API RP 1171.

If DOGGR elects to retain the prescriptive construction, testing, monitoring, and data collection requirements in the Proposed Rule, some changes are necessary to make the proposed requirements more effective and feasible:

1. DOGGR should request that the Department of Energy (DOE) conduct studies through the National Labs, with industry input, to confirm actual effectiveness of the construction requirements, relative to other alternatives.
2. DOGGR defers to ARB in establishing an inspection and leak detection protocol, but ARB's proposed requirements rely on technologies that have not yet been proven. DOGGR should consider a staged implementation approach that includes a design and testing phase prior to requiring compliance with performance objectives.
3. DOGGR should allow operators at least one year to submit Risk Management Plans from the effective date of the Final Rule.
4. Additionally, DOGGR should collaborate with industry to establish realistic timelines for conformance with the extensive construction, testing, monitoring, and data collection requirements of the Proposed Rule. Operators should define these timelines as part of their Risk Management Plans.