BEFORE THE

UNITED STATES DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

WASHINGTON, D.C.

Pipeline Safety: Safety of Underground Natural Gas Storage Facilities Interim Final Rule	Docket No. PHMSA-2016-0016

COMMENTS OF

THE AMERICAN GAS ASSOCIATION

THE AMERICAN PETROLEUM INSTITUTE

THE AMERICAN PUBLIC GAS ASSOCIATION

THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

February 17, 2017

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I. INTRODUCTION

The American Gas Association (AGA), American Petroleum Institute (API), American Public Gas Association (APGA), and Interstate Natural Gas Association of America (INGAA) (jointly the Associations) jointly submit these comments on the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Interim Final Rule establishing for the first time Federal pipeline safety regulations for underground natural gas storage facilities (Interim Final Rule or IFR).[1] The Associations appreciate the opportunity to provide these comments, and offer revisions that are necessary to ensure a workable rule.[2]

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. Forty-four of these members operate 292 underground natural gas storage fields, including 14,101 wells. There are more than 73 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — more than 69 million customers — receive their gas from AGA members.

API is the national trade association representing all facets of the oil and natural gas industry including the transportation and storage of natural gas. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, underground storage, and marine businesses, and service and supply firms.

APGA[3] is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 700 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America. INGAA's members represent the vast majority of the interstate natural gas transmission pipeline companies in the

[1] Pipeline Safety: Safety of Underground Natural Gas Storage Facilities Interim Final Rule, 81 Fed. Reg. 91,860 (Dec. 19, 2016).

[2] On January 18, 2017, the Associations filed a Petition for Reconsideration with PHMSA, requesting that PHMSA promptly revise its regulations for underground natural gas storage facilities at 49 C.F.R. § 192.12 to provide for reasonable implementation periods and to incorporate by reference RP 1170 and 1171 without modification. The Associations reiterate those comments, and provide PHMSA with additional comments that are necessary to ensure that the regulations provide operators of underground natural gas storage facilities with clear regulatory requirements.

[3] Although APGA's members are not operators of underground natural gas storage facilities, APGA has a significant interest in the Interim Final Rule as consumers of storage services.

United States, operating approximately 200,000 miles of pipelines and over 10,000 storage wells, and serve as an indispensable link between natural gas producers and consumers.

Underground storage of natural gas is an integral component of the nation's energy system, and our nation's significant storage capacity enables storage operators and utilities to offer clean natural gas to consumers reliably throughout the year in a cost-efficient manner and without interruption. Each Association and its member companies has a strong commitment to advancing pipeline and underground natural gas storage safety. Building upon this commitment, the Associations fully supported the development of industry-wide safety standards for underground natural gas storage. As a result of these efforts, with input from national experts and stakeholders, including PHMSA and state regulators, API issued two Recommended Practices (RPs): API RP 1170: *Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage*[4] and API RP 1171: *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*[5] (jointly the Recommended Practices).

Storage operators' adoption of these Recommended Practices, as published by API, at all underground natural gas storage facilities will result in the most comprehensive safety enhancement to underground natural gas storage made in decades, and will apply to all aspects of the underground gas storage life cycle. The Recommended Practices appropriately recognize the diversity of underground natural gas storage facilities throughout the U.S. and are not limited to addressing facilities in a single state, basin, geological setting, or well type. By incorporating the Recommended Practices by reference, PHMSA's Interim Final Rule directs operators to implement a functional integrity management system, which includes the requirement for rigorous risk assessment to establish the appropriate preventative and mitigative measures to address the unique characteristics of each underground storage facility. Implementing the IFR will require significant and diligent effort by operators. Although operators have begun the implementation process, no operator has fully implemented all aspects of the Recommended Practices.

In developing the Recommended Practices, the authors carefully evaluated existing state regulations. They found that states had widely-varying requirements and did not identify any state regulatory framework or set of requirements that could comprehensively address all aspects of underground gas storage functional integrity on a national level. No state contains the diversity of gas storage fields and wells that would result in the fully-encompassing set of standards that the authors of the Recommended Practices were seeking. Therefore, the Associations commend

[4] API Recommended Practice 1170 "Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage" (1st edition, July 2015).

[5] API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (1st edition, September 2015).

PHMSA for applying the Recommended Practices, through the IFR, to all interstate and intrastate underground natural gas storage facilities throughout the nation.

The Recommended Practices appropriately recognize and address the diversity of underground natural gas storage facilities nationwide and appropriately serve as nationwide standards for underground natural gas storage functional integrity. That being said, PHMSA must promptly revise certain aspects of the IFR to ensure a practicable and effective final rule for underground natural gas storage facilities, including:

- Provide for *reasonable implementation periods*, as outlined in these comments;
    - Within 12 months, operators must have the foundational components of a functional integrity management system, including a written framework
    - Within three years, operators must have a storage functional integrity management system in place
    - Within 3 – 8 years, operators must complete underground gas storage facility risk assessments, including the baseline integrity assessments and preventative and mitigative measures warranted by the risk assessment.
- Incorporate by reference API RP 1170 and 1171 *without modification* of non-mandatory provisions;
- Incorporate underground natural gas storage facilities into a new "Part 19X," *separate from Part 192*; and
- Provide additional clarification on implementation through FAQs that can be used by operators while PHMSA revises the Final Rule. Topics warranting clarification are outlined in these comments.

The Associations and our members look forward to working with federal and state partners to advance our shared goal of ensuring strong and proven underground gas storage integrity. In that spirit, the Associations offer the following detailed comments on several aspects of the IFR that must be modified or further refined to assure a practicable and effective set of Federal regulations for the safety of underground natural gas storage facilities.

II. TIMING OF IMPLEMENTATION

It Is Not Practicable for Operators to Implement the Interim Final Rule by January 18, 2018.

In the Interim Final Rule, PHMSA requires that existing underground natural gas storage facilities using a solution-mined salt cavern for storage meet the requirements of API RP 1170, sections 9, 10, and 11, by January 18, 2018.[6] Similarly, PHMSA requires that existing underground natural gas storage facilities using a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage meet the requirements of API RP 1171, sections 8, 9, 10, and 11, by January, 18, 2018.[7,8] The plain text of the IFR requires operators of natural gas storage facilities to implement all actions under the applicable sections of API RP 1170 and 1171 within one year of the effective date of the IFR, January 18, 2017.[9] Based on the IFR's preamble and PHMSA's Underground Natural Gas Storage FAQs,[10] the Associations do not believe this was the intent of the IFR, as this time frame is not just unreasonable, but simply not practicable, and would not substantively fulfill the goal of the IFR and the Recommended Practices – to increase safety. While the Associations appreciate the intent of the FAQs, as discussed below, the clarifications on schedule and deadlines must be included in the Final Rule.

The Recommended Practices (API RP 1170 and 1171) direct a risk-based approach to addressing the safe design, operation, and maintenance of existing underground natural gas storage facilities. Many of the requirements in both Recommended Practices are intended to be sequential and build upon one another. There is a necessary sequential progression and coordination of actions that operators must take in order to fully implement the Recommended Practices. It is important to understand that allocating additional resources will likely have limited impact since many actions must be taken sequentially instead of simultaneously. As such, there is a minimum amount of time necessary to work through the steps.

Actual operator experience in developing standardized storage functional integrity management systems, as required by the IFR, suggests that more than 12 months are needed for implementation. In part, significant time is required for internal familiarization, development of procedures, implementation of training, and holistic adoption of integrity management concepts in

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[6] 49 C.F.R. § 192.12(b).

[7] 49 C.F.R. § 192.12(d).

[8] Included in both Sections 192.12 (b) and (d) is a list of topics from the Recommended Practices that operators must comply with. *Id*. ("operational, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping"). Because these terms are not taken directly from the Recommended Practices, it is not clear what regulatory purpose PHMSA intended by including this list.

[9] 81 Fed. Reg. 91,861.

[10] PHMSA, Underground Natural Gas Storage: FAQs, Dec. 19, 2016, https://primis.phmsa.dot.gov/UNG/faqs.htm.

order to integrate a storage functional integrity management system and the "plan-do-check-act" process cycle for storage assets.

One operator has documented their experience with building a storage functional integrity management system consistent with the incorporated Recommended Practices. Over an 18-month period beginning in 2013, the operator assembled internal and external subject matter experts and drafted, reviewed, and refined over 30 engineering standards, procedures, integrity plans, and related operating practices covering storage well and storage reservoir life cycle activity. The operator relied on 10 individuals, each with an average of 20 years of subject matter experience, to complete the tasks. This operator believes there is equally as much work remaining as has already been accomplished in order to complete the first cycle of planning in their "plan-do-check-act" process cycle.

Another observation from actual experience developing a storage functional integrity management system highlights the time required for just one step in the process: reviewing and analyzing a well file. A well file typically includes paper documents such as permitting documents, equipment and material records, drilling and completion histories, and operational records. The Recommended Practices direct a more structured and standardized process for organizing and reviewing this information than processes that may have been used in the past. It is not unusual for the process of reviewing and analyzing a well file to take 5 to 10 hours per well. For an operator of 500 wells, this process alone can require 30 man-months and does not include the time required to further incorporate and make the information in the file useful and available via a data management system.

Additionally, there are numerous logistical and administrative hurdles that make a one-year compliance time frame not practicable. There is limited specialized equipment and qualified personnel available to perform much of the work that could be required to implement the Recommended Practices incorporated in the IFR. For example, API RP 1171 Section 9.3 requires operators to evaluate and monitor well integrity. Based on the outcome of an operator's risk evaluation, this section could require the use of wireline and/or "slickline" trucks and multi-caliper tools to conduct downhole casing inspection logging, along with personnel qualified to conduct these complex operations. The limited availability of equipment and personnel will have a direct impact on the timing of implementing the IFR. PHMSA's one-year compliance time frame cannot be achieved given the necessary scheduling and allocating of this specialized equipment and qualified personnel.

Operators will be creating and implementing these functional integrity management systems contemporaneously with executing on-going, planned storage well integrity work. Storage operators have not waited for regulatory action to maintain their storage wells and there will not be a hiatus of scheduled well integrity work while functional integrity management system frameworks are being put in place. As such, not all of an operator's storage resources and subject matter experts can or should be expected to be completely dedicated to IFR plan development.

The process for implementing the Recommended Practices will be similar in many ways to the Gas Transmission Integrity Management ("Gas IM") regulations, which PHMSA promulgated in 2004.[11] In developing the Gas IM regulations, PHMSA acknowledged that a sequential series of actions over a period of time would be necessary for operators to develop sophisticated and effective integrity management programs.[12] The Gas IM regulations required operators to develop baseline plans for implementing assessment requirements within one year, and required assessments to be completed within ten years (with 50% being required within five years).[13]

To better define what is achievable by January 18, 2018, the Associations suggest that the foundational components of a storage functional integrity management system can be put in place and available for inspection by PHMSA within 12 months of the Effective Date of the IFR. Foundational components include the written framework, which would identify the integrity management program as well as plans and procedures to be developed during the full-development phase of the system. Specifically, these foundational components would include a plan for developing procedures, a specific breakout of how the applicable Recommended Practice requirements would be addressed in the management system framework and its procedures, an outline of the procedures to be developed, the resources committed to the development and implementation, how staff will be trained in awareness and application of the procedures, and an implementation schedule. These components must be prepared thoughtfully as they represent the roadmap for development of an operator's storage functional integrity management system.

Based on operators' experiences in beginning to build these storage functional integrity management systems, we strongly recommend that PHMSA set the requirement to three years for operators to have a storage functional integrity management system in place, including programs for training and qualifying staff and contractors on requirements, building competency, maintain databases, and assuring supervision and documentation.

In addition, the Associations request that PHMSA incorporate the risk assessment and integrity assessment timelines currently outlined in Underground Natural Gas Storage FAQs 5 & 6.[14] Operators would be required to complete an underground natural gas facility risk assessment,

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[11] 49 C.F.R. Part 192, Subpart O.

[12] PHMSA, Gas Transmission Integrity Management: FAQs, (Integrity Management Programs FAQ-74, Dec. 17, 2004; Time Periods FAQ-124, March 9, 2005; Time Periods FAQ-237, Dec. 12, 200) https://primis.phmsa.dot.gov/gasimp/faqs.htm.

[13] 49 C.F.R. § 192.921(d).

[14] PHMSA, Underground Natural Gas Storage: FAQs, Dec. 19, 2016, https://primis.phmsa.dot.gov/UNG/faqs.htm.

including preventive and mitigative measures, within 3 to 8 years, depending on the size, complexity and initial risk evaluation of the facilities. As warranted by the risk assessment, baseline integrity assessments in each storage field would start within two years of the effective date of the rule, beginning with the highest risk facilities identified from the risk assessment process. Baseline assessments in each storage field would be completed within 3 to 8 years, depending on the size and complexity of the storage field and as warranted by the risk assessment. Operators would expedite implementation of preventive and mitigative measures for high risk or imminent risk facilities as identified by their risk assessment.

III. REQUIRING ALL "NON-MANDATORY" PROVISIONS OF THE RECOMMENDED PRACTICES

PHMSA's Requirement that All "Non-Mandatory" Provisions of the Incorporated Recommended Practices Are Mandatory is Not Necessary for PHMSA's Enforcement and Makes the Interim Final Rule Unreasonable

API RPs 1170 and 1171 are intended to maintain functional integrity through design, construction, operation, monitoring, maintenance, and documentation practices for underground natural gas storage facilities. To achieve this integrity, the Recommended Practices contain numerous provisions that use the term "shall" to denote a minimum requirement in order to comply with the RP. The Recommended Practices also use non-mandatory terms such as "should," "may," or "can" to denote a recommendation that is advised, but not required in order to conform to the specification.

In the IFR, PHMSA requires that all "non-mandatory provisions (i.e., provisions containing the word 'should' or other non-mandatory language) are adopted as mandatory provisions" for the incorporated Recommended Practices.[15] According to PHMSA, adopting non-mandatory provisions as mandatory is necessary to address PHMSA's "concerns about the enforceability of these [recommended] practices."[16] However, changing the Recommended Practices in this manner is not necessary for enforcement, nor is it practicable or reasonable. For the reasons outlined below, the Associations believe that there is no regulatory justification for making all "non-mandatory" provisions "mandatory," and request that PHMSA eliminate 49 C.F.R. § 192.12(f).

The Recommended Practices Contain Sufficient Mandatory Provisions to Ensure Enforceability.

Although both RP 1170 and 1171 contain non-mandatory provisions, this fact alone does not affect the enforceability of the Recommended Practices. Throughout the Recommended

[15] 49 C.F.R. § 192.12(f).

[16] 81 Fed. Reg. 91,865.

Practices, there are mandatory statements imposing broad obligations on operators of underground natural gas storage facilities. For example, within RP 1171 Section 8 "Risk Management for Gas Storage Operations," there is a broad obligation imposed on operators to develop, implement, and document a comprehensive risk management plan consistent with the intended actions of RP 1171:

> The operator shall develop, implement, and document a program to manage risk that includes data collection, identification of potential threats and hazards to the storage operation, risk analysis including estimation of the likelihood of occurrence of events related to each threat, the likelihood of occurrence and potential severity of the consequences of such events, and the preventative, mitigative, and monitoring processes to reduce the likelihood of occurrence and/or the likelihood and severity of consequences, and a periodic review and reassessment of the processes.[17]

Subsequent parts of Section 8 related to specific components of a risk management program – such as threat and hazard identification and preventative and mitigative measures – include non-mandatory statements. However, these non-mandatory statements do not compromise the enforceability of the broad obligations imposed on operators through the mandatory requirements. Instead, the non-mandatory statements provide best practice recommendations that operators should consider and apply in many situations, where warranted by site-specific conditions, but are not necessary for safety in all situations. When evaluating a storage operator's functional integrity management program and its effectiveness in achieving the mandatory obligations outlined in the Recommended Practices, PHMSA inspectors should still reference the non-mandatory practices; these are important practices that prudent operators will often employ, but may not be necessary or practicable for functional integrity at every facility, based on site-specific factors.

As a specific example, API RP 1171 Section 8.7.1 requires an operator to assess the effectiveness of risk monitoring and risk management programs and maintain a continual review and improvement cycle, but provides discretion on the interval of review and reassessment.[18] This discretion does not compromise the enforceability of the obligation to assess the effectiveness of the risk programs, or PHMSA's ability to issue a corrective order if an operator does not implement an effective review and improvement cycle.

Operator discretion and the use of non-mandatory provisions within pipeline safety regulations is not new, and is not limited to documents incorporated by reference. For example,

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[17] API RP 1171 Section 8.2 (emphasis added).

[18] *Id*. at Section 8.7.1 ("The operator shall assess the effectiveness of risk monitoring and risk management programs and maintain a continual review and improvement cycle. . . The interval of review and reassessment should be short enough to identify operational and monitoring trends and measure the effectiveness of P&M measures . . . .") (emphasis added).

PHMSA's requirements for operators to take additional preventative and mitigative measures on transmission pipelines in high consequence areas provides the operator with discretion to implement measures that the operator determines are required based on a risk assessment:

> An operator must base the additional measures on the threats the operator has identified to each pipeline segment. . . . An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S . . . a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

The regulations clearly put the burden and discretion on operators to determine the appropriate preventative and mitigative measures to implement. Similarly, PHMSA has incorporated by reference other API Recommended Practices without the caveat that non-mandatory statements must be mandatory for enforcement purposes.[19] "Should" requirements are enforceable by PHMSA in appropriate circumstances, just as "shall" requirements are enforceable.

Finally, the fact that API elected to issue API RPs 1170 and 1171 as "recommended practices" has no bearing on the enforceability of the Recommended Practices.[20] API Standards include several different types of documents, including "specifications," "recommended practices," "standards," and "codes."[21] Recommended Practices" are simply a type of API standard that communicate recognized industry practices and may include both mandatory and non-mandatory requirements. PHMSA's enforceability of these provisions is not compromised by using "should" in the regulatory text. As such, PHMSA should not be concerned with the enforceability of the non-mandatory provisions in the Recommended Practices.

<u>PHMSA's Broad Requirement That All Non-Mandatory Provisions Become Mandatory Has Resulted in a Regulation That is Not Practicable and is Unreasonable.</u>

In Section 49 C.F.R. § 192.12(f), PHMSA has added regulatory language stating that "the non-mandatory provisions (i.e., provisions containing the word 'should' or other non-mandatory

[19] *See. id*. at § 192.7(b)(1)-(3) (incorporating by reference API Recommended Practice 5L1, 5LT and 5LW).

[20] 81 Fed. Reg. 91865 ("API elected to issue RPs 1170 and 1171 in the form of 'recommended practices,' as opposed to 'standards.' This presented PHMSA with the challenge of dealing with concerns about the enforceability of these practices.").

[21] API, Procedures for Standards Development, Fifth Ed. April 2016, ANSI Approved June 2016 at 3.

language) are adopted as mandatory."[22] By including this language, PHMSA has significantly altered the Recommended Practices and has created regulatory requirements that are not practicable and are unreasonable.

The Recommended Practices were adopted with definitions of "shall" and "should" and the understanding that the term "should" would denote "a recommendation of that which is advised but not required in order to conform to the specification."[23] These terms are often included where a recommendation may not be appropriate or practical in all situations, or may be inappropriate due to site-specific conditions. For example, in API RP 1171 Section 6.4.5 "Cement Pumping Design," the RP recommends that pipe movement during hole conditioning and cement pumping be employed:

> When feasible, pipe movement (i.e., either rotation or reciprocation of the casing) during hole conditioning and cement pumping should be employed to help eliminate the possibility of cement channeling. (emphasis added)

Under Section 192.12(f), the requirement to employ pipe movement would become mandatory. However, pipe movement is not appropriate in all situations and could actually damage the seal between the pipe and caprock, which can result ultimately in the collapse of the hole or a stuck pipe.

The changes to the Recommended Practices through Section 192.12(f) also impose obligations on activities outside the control of underground natural gas storage operators. For example, API RP 1171 Section 9.4.3 "Third-Party Activity," states that "[t]hird-party wells located within the lateral and vertical buffer zone being plugged and abandoned by the third party should be plugged in a manner to isolate the storage reservoir and protect its integrity." (emphasis added). While this is certainly a best practice, operators of underground natural gas storage facilities have no control or authority to ensure that third-party wells meet this requirement. Similarly, API RP 1171 Section 10.3.1 would require operators to maintain lease or well roads, even though many of these roads are not owned by underground natural gas storage operators, but are owned by third parties or government entities.[24]

In addition to applying to "should" statements, Section 192.12(f) also applies to "other non-mandatory language" contained in the Recommended Practices. As a result, phrases such as "can" and "may" within the Recommended Practices may be treated as "shall." Such revisions are problematic and create numerous nonsensical regulatory requirements. For example, API RP

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[22] 49 C.F.R. § 192.12(f).

[23] API RP 1171 at iii; API RP 1170 at iii.

[24] API RP 1171 Section 10.3.1 (Lease or well roads ~~should~~ shall be maintained in a condition that permits personnel and equipment access to the well.).

1171 Section 11.12.4 could be interpreted to *require* the use of contractor personnel in the performance of construction, operating, maintaining and monitoring duties associated with storage wells and reservoirs. Clearly, this is not the intent of this section of the Recommended Practice.[25] Similarly, section 8.4.1 could *obligate* operators to determine that some storage facilities are not susceptible to specific threats based on existing information, which is clearly contrary to the goals of this IFR.[26]

The Associations have identified numerous non-mandatory provisions in the Recommended Practices that would create significant unintended consequences and an unreasonable burden on operators if made mandatory. Appendix A contains a detailed list of many of these provisions.

PHMSA has indicated their intent to "further evaluate the need for any additional regulatory requirements for underground storage facilities," after the issuance of the IFR.[27] During this evaluation period, it would be appropriate for PHMSA to establish a process for exploring additional requirements, beyond the mandatory requirements prescribed in the Recommended Practices, and for developing the language and applicability of additional mandatory requirements. This process should include an opportunity for discussion with key stakeholders, including storage operators, and could also inform the next edition of the Recommended Practices.

As currently enacted, the revisions to the Recommended Practices that result from current Section 192.12(f) result in unreasonable, not practical and often nonsensical regulatory requirements imposed on operators of underground natural gas storage facilities. The Associations strongly encourage PHMSA to eliminate the requirement in Section 192.12(f) that all "non-mandatory provisions (i.e., provisions containing the word 'should' or other non-mandatory language) are adopted as mandatory provisions."[28]

<u>The Procedure for Obtaining a Variance from the Recommended Practices is Unworkable and a Departure from PHMSA's Past Position</u>

Under Section 192.12(f), PHMSA has provided operators of underground natural gas storage facilities with a procedure for deviating from the incorporated Recommended Practices. However, because the procedure would only apply in narrow circumstances and is unreasonably

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[25] API RP 1171 Section 11.12.4 Contractor Personnel (The operator ~~may~~ <u>shall</u> use contractor personnel in the performance of constructing, operating, maintaining, and monitoring duties associated with storage wells and reservoirs. This subsection provides recommendations regarding training of contractor personnel.).

[26] API RP 1171 Section 8.4.1. General (The operator ~~may~~ shall determine that some storage facilities are not susceptible to specific threats based on existing information, in which case the operator can provide justification and documentation for the exclusion of a specific threats.).

[27] 81 Fed. Reg. 91861.

[28] 49 C.F.R. § 192.12(f).

burdensome, many operators could be left with essentially no mechanism for obtaining a variance from the incorporated Recommended Practices.

PHMSA establishes a reasonable test to support a variance: "no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety."[29] However, inconsistent with this test is general language limiting the availability of variances to situations where an action is "not practicable <u>and</u> not necessary for safety."[30] As a result, the variance process may not be available for an action that is "not necessary for safety," but that may otherwise be practicable to implement. It is unlikely that the resulting waste of operator resources is intended. Likewise, the variance process should be available for actions that simply are not practicable to implement. By definition, an action that is not practicable cannot be put into practice, yet that alone is not sufficient for an operator to avail itself of the variance procedure. Requiring both prongs of the test to be met is unduly burdensome.

Second, in the event that an action meets the "not practicable and not necessary for safety" standard, operators must then provide a substantial amount of justification from a subject matter expert that there will be <u>no</u> adverse impact on any aspect of the storage facility, and this justification must be signed by a corporate executive.[31] The amount of certainty and justification necessary to use the variance, coupled with the corporate signature requirement, essentially ensures that use of the variance process will be impracticable.

The variance process required in the IFR is a time intensive, expensive process for each variance and is a substantial departure from PHMSA's prior positions on variances. In 1999, the Research and Special Programs Administration, PHMSA's predecessor agency, stated that operators should have some discretion when complying with recommended practices and that an operator should note in its procedural manual the reasons why compliance with provisions was not necessary for safety.[32] Several years later, in 2005, when adopting a recommended practice for public awareness, PHMSA stated that it was not its intent "that every occurrence of 'should,' 'may,' or 'can' found in API RP 1162 be translated to 'shall' as a result of the incorporation."[33] Instead, operators should document in procedural manuals "the reasons why compliance with all or certain provisions of the practice is circumstantially unnecessary."[34]

When compared to these prior variance requirements, which are still onerous, the variance requirements in the IFR are unworkable for many operators. The burden associated with the

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[29] 49 C.F.R. § 192.12(f).
[30] 49 C.F.R. § 192.12(f) (emphasis added).
[31] *Id*.
[32] Pipeline Safety: Adoption of Consensus Standards for Breakout Tanks, 64 Fed. Reg. 15,926, 15929 (April 2, 1999).
[33] Pipeline Safety: Pipeline Operator Public Awareness Program, 70 Fed. Reg. 28,833, 28,837 (May 19, 2005).
[34] *Id*. Although the final regulatory text required operators to provide justification as to why compliance was not practicable and not necessary for safety, PHMSA's statements in the preamble suggest a less burdensome variance process than that included in the Interim Final Rule.

variance process is magnified by PHMSA adopting non-mandatory provisions that were never intended to apply to all facilities as mandatory. Accordingly, the Associations request that PHMSA revise the IFR to require operators to document variances in its procedural manual similar to the 1999 or 2005 methodology or allow for variances in situations where an action is "not practicable or not necessary for safety."

IV. MOVING UNDERGROUND STORAGE REGULATIONS FROM 49 C.F.R. 192

PHMSA Should Create a New Part Within Subchapter D for Underground Natural Gas Storage Facility Regulations to Ensure Clarity and Avoid Confusion with the Regulations for Pipeline Facilities in Part 192

To assure clarity with respect to current and future regulatory requirements for underground natural gas storage facilities, PHMSA should move § 192.12 to a new Part within Subchapter D of PHMSA's regulations. The Associations refer to this new Part as "Part 19X."

The Associations are concerned that these definitions and the inclusion of the underground natural gas storage facility regulations in Part 192 may result in the application of additional subparts or provisions of Part 192 to underground storage facilities, beyond the requirements outlined in § 192.12. Definitions for key terms used in § 192.3 were developed prior to PHMSA's regulation of underground natural gas storage facilities and apply throughout Part 192. These key terms are used to define the Scope of each subpart within Part 192. It is unclear how these terms would relate to storage facilities, and what impacts their application to storage facilities could have. The Associations have concerns regarding several of the definitions from § 192.3, including:

> *Pipe* means any pipe or tubing used in the transportation of gas, including pipe-type holders.
>
> *Pipeline* means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.
>
> *Pipeline environment* includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.
>
> *Pipeline facility* means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

The Associations do not believe that any of these key terms are intended to apply to underground natural gas storage facilities. However, PHMSA developed these definitions prior to promulgating underground storage facility regulations, and it is ambiguous whether each of these key terms could apply to underground storage facilities.

The application of additional subparts or provisions of Part 192 to underground natural gas storage facilities also could create an array of conflicts with the design, construction, and O&M practices prescribed by API Recommended Practices 1170 and 1171 and could result in some inappropriate and nonsensical requirements when applying *pipeline* regulations to *storage* facilities or *storage* regulations to *pipeline* facilities. Furthermore, application of additional subparts or provisions of Part 192, outside of § 192.12, to underground natural gas storage facilities was not analyzed in PHMSA's Notice of Interim Final Rule or Regulatory Impact Analysis.

While both pipelines and storage wells use cylindrical steel tubes placed underground as their main attribute, and employ similar types of equipment (valves, fittings, etc.), their respective methods of design, construction, and purpose are significantly different, requiring significantly different engineering practices. As a result, there are different API and ASME standards for the piping and equipment that are used in these different applications.

The Associations have conducted a detailed review comparing Part 192 with API RP 1170 and 1171 and have identified an array of potential conflicts. A few examples of such conflicts are described below:

- *§ 192.105 – Design formula for steel pipe:* § 192.105 outlines the design formula for line pipe. Clearly, different design considerations are necessary for vertical casing strings within storage wells, and these considerations are outlined in Section 6 of both API RP 1170 and 1171. Both Recommended Practices reference API Bulletin 5C3 on "Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties," which provides the appropriate design guidelines for casing and tubing within underground gas storage wells.

- *§ 192.145 – Valves:* § 192.145 specifies requirements for pipeline valves, including incorporation of ANSI/API Specification 6D, a discussion of pressure and temperature ratings for service, and other requirements. ANSI/API Specification 6D is a pipeline valve standard. "API 6A: Specification for Wellhead and Christmas Tree Equipment" is a rigorous standard that is the appropriate specification for wellhead valves associated with underground natural gas storage facilities. Both Recommended Practices reference API 6A.

  While it may appear simple just to modify § 192.105 to reference API 5C3 for storage well strings and modify § 192.145 to reference API 6A for storage well valves, these are just two instances among many where qualifying text would need to be added to a multitude of Part 192 sections to address the insertion of storage technology and practices into the existing pipeline regulations.

- *§ 192.455 & § 192.457 – External Corrosion Control:* § 192.455 & § 192.457 describe requirements for cathodic protection and coating systems to control external corrosion on pipelines. As PHMSA discussed in the Notice of Interim Final Rule, storage wells commonly do not have cathodic protection or coating. Employing coating is problematic for storage wells, due to the process for joining two pieces of casing together (screwing with pipe tongs) and then running the casing into a hole for hundreds or thousands of feet along the side of the hole and shallower casing strings. It would also be difficult to impress CP onto all strings of casing, particularly production casing that is bonded to cement. Cement provides corrosion protection, and underground gas storage facility operators can monitor for corrosion using a variety of integrity assessments, as outlined in both Recommended Practices.

- *§ 192.903 – Subpart O Definitions:* § 192.903 outlines the methodology for determining whether a pipeline segment is located in a High Consequence Area (HCA) and subject to the rigorous integrity management requirements designed to minimize the risk from a *pipeline* incident in HCAs. The definitions and calculations outlined in § 192.903, and many of the preventative and mitigative measures outlined in Subpart O, are specific to pipelines.

  While Subpart O applies to a specific subset of pipelines, the Recommended Practices outline a functional integrity management system that is applicable to *all* storage wells and reflects many of the same risk management principles as Subpart O. PHMSA's Interim Final Rule requires operators of underground natural gas storage facilities to conduct risk assessments as a basis for selecting and implementing preventative and mitigative measures. These assessments must consider the unique consequences of events on a site-specific basis.

There are important aspects of underground natural gas storage facility safety that had not been addressed in PHMSA's regulations until the Recommended Practices were incorporated by reference in §192.12. These aspects include design and operational considerations related to the geological formations that compose the storage reservoir; the sealing formations above, below, and lateral to the storage reservoir; and the shallower formations that may have an impact on well drilling and casing integrity. Outside of §192.12, none of the existing subparts of Part 192 are structured, nor particularly applicable, to address these formation issues since pipelines are not placed in such a deep environment.

Compounding these concerns, PHMSA's "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" Notice of Proposed Rulemaking[35] proposes substantial changes to Part 192, and would potentially add additional requirements for corrosion control, preventative and

[35] 81 Fed. Reg. 20,722 (April 8, 2016)

mitigative measures, and repair criteria that are very specific to integrity management for *pipeline* systems. Inappropriately applying these new requirements to underground natural gas *storage* facilities would likely result in an ineffective allocation of resources not addressed by the Proposed Rulemaking or its supporting Preliminary Regulatory Impact Analysis. PHMSA is continuously revising and restructuring Part 192 in an attempt to more effectively regulate pipeline safety. Similarly, in the Preamble to the Interim Final Rule, PHMSA indicates that it "plans to incrementally build on the framework of the IFR as necessary." Since the primary focus of Part 192 is natural gas transmission and distribution pipelines, it may be challenging for PHMSA to make further additions and structural changes to Part 192 to address transmission and distribution pipelines, while also building storage regulations within Part 192. There is a clear precedent for promulgating regulations for assets other than pipeline systems outside of Part 192: federal safety standards for liquefied natural gas (LNG) *storage* facilities are contained in Part 193.

For these reasons, the Associations encourage PHMSA to move the underground storage regulations to a new subpart (referred to as "Part 19X"). Furthermore, PHMSA should clarify that "Part 19X" does not apply to the pipeline facilities regulated under 49 C.F.R. Part 192. As noted by the examples earlier in this section, different engineering principles underlie the design, operations, and maintenance of underground natural gas storage facilities, as opposed to pipeline facilities.

While the Associations believe it is critical for the underground natural gas storage regulations to be contained within their own Part to ensure regulatory clarity, we believe PHMSA should work with industry, state regulators, and the public to leverage learnings from the development of Part 192 in considering future additional underground natural gas storage facility safety requirements. Part 192 is the product of decades of continuous improvement in the pipeline safety regulatory framework. There are certainly practices outlined in Part 192 that could ultimately add value to underground natural gas storage functional integrity management systems, if modified to apply to underground storage facilities and incorporated into "Part 19X." The Associations believe that such an analysis comparing Part 192 to API Recommended Practices 1170 and 1171 would also be beneficial in informing future editions of these Recommended Practices. The incorporation of selected key points from Part 192 into the Recommended Practices and "Part 19X" would leverage learnings from the development of Part 192, while avoiding the regulatory conflict and confusion that would be created by trying to incorporate the Recommended Practices into Part 192's existing Subparts.

V. PHMSA'S FREQUENTLY ASKED QUESTIONS ON UNDERGROUND STORAGE

On December 19, 2016 PHMSA issued Underground Natural Gas Storage: Frequently Asked Questions (FAQs), which are intended to "clarify, explain, and promote better understanding of issues concerning integrity assessment of Underground Natural Gas Storage Facilities."[36] This effort follows the precedent of utilizing FAQs to clarify the gas transmission and distribution integrity management regulations.[37;38] The Associations appreciate these FAQs for use in the interim while PHMSA revises the Final Rule and are committed to working with PHMSA to further develop and clarify these FAQs.[39]

PHMSA Should Provide Further Clarity Regarding Implementation Timelines and Expectations within 12 months

Currently, the FAQs explain that existing UGS facilities must have in place by January 18, 2018 "appropriate operational, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping *procedures*, along with implementation *plans* and *schedules*." (emphasis added).[40] The list of topics for which procedures, implementation plans and schedules must be implemented within one year is incredibly broad, and does not correspond with specific actions required by the Recommended Practices during initial development of a functional integrity management system framework.

As described above, the Associations suggest that the FAQs and the Final Rule recognize that foundational components of a storage functional integrity management system can be put in place and available for inspection by PHSMA within 12 months of the Effective Date of the IFR. Foundational components would include the written framework, which would identify the integrity management program as well as plans and procedures to be developed during the full-development phase of the system. Specifically, these foundational components would include a plan for developing procedures, a specific breakout of how the incorporated Recommended Practice requirements would be addressed in the management system framework and its procedures, an outline of the procedures to be developed, the resources committed to the development and implementation, how staff will be trained in awareness and application of the procedures, and an implementation schedule.

[36] PHMSA, Underground Natural Gas Storage: FAQs, Dec. 19, 2016, https://primis.phmsa.dot.gov/UNG/faqs.htm.
[37] PHMSA, Underground Natural Gas Storage: FAQs, https://primis.phmsa.dot.gov/dimp/ .
[38] PHMSA, Underground Natural Gas Storage: FAQs, https://primis.phmsa.dot.gov/gasimp/faqs.htm .
39 Although the Associations appreciate PHMSA's efforts to address some of their concerns regarding timing through FAQs, the Associations believe that the regulatory text must be revised to provide regulatory clarity and certainty, consistent with these comments and the Association's Petition for Reconsideration.

[40] PHMSA, Underground Natural Gas Storage: FAQs, Question 1, Dec. 19, 2016.

PHMSA Should Provide Further Clarity Regarding Requirements for New Components, which are Outlined in FAQ #7

FAQ #7 outlines requirements for the replacement, expansion, or addition of "significant facilities" with an existing storage facility:

> The replacement, expansion or addition of significant facilities (such as new wells, tubing, casing or wellheads) within an existing facility will be considered as new UGS facilities, if they are constructed after July 18, 2017. Those facilities must meet the applicable requirements in §192.12(a) or (c).

The Associations believe PHMSA's intent is to require that for new components installed after July 18, 2017, *only the newly-installed component* would be subject to the new construction requirements in the Recommended Practices. PHMSA should clarify this in FAQ #7 and, ultimately, in the Final Rule.

In addition, PHMSA should redefine what is meant to be included within the "significant facilities" designation. The definition of "significant facilities" should be limited to new wells, casing, or wellhead, and should not include tubing or other routine, minor maintenance items. For example, replacing 40 feet of tubing that may be 4,000 feet in length should not be considered significant.

PHMSA Should Clarify Notification Requirements in § 192.22

Regarding National Registry Notifications, the IFR added as 191.22(c)(1)(iv):

> (iv) Construction of a new underground natural gas storage facility or the abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility.

PHMSA should provide further clarification in the FAQs and the Final Rule regarding the types of changes to underground natural gas storage facilities that require notification under § 191.22. Many operations and maintenance activities could be described to include a "well workover." Thousands of these events occur nationally each year; we do not believe PHMSA intends for each of these activities to be reported 60 days in advance.

PHMSA has provided the Associations with some clarification, via email, that only well workovers that involve replacement should be reported, and notifications for operations and maintenance activities should not be reported. Still, the Associations believe this guideline is ambiguous and inconsistent with the scale of changes to pipelines that currently require reporting under § 191.22. Notification is required for pipeline work that costs over $10 million dollars, involves construction of 10 or more miles of new pipe, or involves construction a new LNG facility. PHMSA should establish a similar threshold for notification of changes to underground natural gas storage facilities in the FAQs and, ultimately, in the Final Rule.

Furthermore, PHMSA should establish expectations for work that operators decide should be conducted in a shorter timeframe than 60 days. For example, an integrity assessment may reveal a condition that warrants a workover as soon as practicable. The Associations believe it would be inconsistent with PHMSA's goals supporting the IFR if operators were required to delay integrity work due to the notification requirement. PHMSA has already provided guidance to the Associations via email that if an operator decides work needs to be done immediately, the operator should not delay the work because of the notification requirement. This guidance should be documented in the FAQs and, ultimately, in the Final Rule.

PHMSA Should Issue FAQs to Clarify Certain Annual and Safety Related Condition Reporting Requirements

PHMSA should use the FAQs to provide clarification on some minor issues related to the new Underground Natural Gas Storage Facility Annual Report:

- For Section "C4: Maximum Wellhead Surface Pressure," PHMSA should clarify that operators are to report the maximum pressure observed during the year at an indicative well for each storage formation.
- For Section "C13: Number of Wells with gas flow only through production tubing," PHMSA should confirm that "hanging string" completions should be included in this count.
- For Sections C21-C23, if the same well undergoes a given mechanical integrity test more than one time during a calendar year, PHMSA should clarify how this should be counted and reported.

In the IFR, PHMSA also extends Safety Related Condition reporting requirements in § 191.23 to underground natural gas storage facilities. PHMSA should use the FAQs to clarify whether operators are to submit two separate reports if there is a safety related condition at a storage facility that impacts a pipeline facility, or vice-versa. For example, how should an operator report a single safety related condition on a pipeline that causes a 20% or more reduction in operating pressure within both the pipeline and an injection well at an associated storage facility?

VI. REGULATORY IMPACT ANALYSIS

In support of the Interim Final Rule, PHMSA has developed a Regulatory Impact Analysis (RIA), which evaluates the expected costs and benefits of the IFR. Although the Associations are supportive of PHMSA adopting the Recommended Practices and the burdens such adoption will impose, PHMSA's RIA includes some inappropriate assumptions and erroneous cost and benefit estimates. The Associations believe it is important that PHMSA recognize the true impacts of the IFR.

Foundational to an agency's requirement to perform a RIA is the requirement to "evaluate benefits and costs against the same baseline."[41] In the RIA, PHMSA outlines three different possible baseline scenarios: full, partial, and regulatory compliance:

- *Full compliance*: For this first scenario, PHMSA assumed that the entire industry would be implementing the API Recommended Practices in the absence of this rule. Based on the voluntary compliance, PHMSA suggests that the costs associated with the measures described in the API Recommended Practices are therefore not attributable to the regulation. PHMSA estimated incremental costs to consist only of those (minimal) costs associated with notifications or reporting to PHMSA, as such reports would not be needed absent the regulatory requirement to provide information to the government.
- *Partial industry compliance*: For this second scenario, PHMSA assumed that only those operators who are INGAA members or have stated publicly that they are implementing the API Recommended Practices would implement the measures in the absence of this rule and that the regulation could therefore impose an incremental cost on all other operators of interstate facilities or of intrastate facilities in states without regulatory requirements. PHMSA considered this baseline to represent a lower bound level of implementation in the absence of the regulation, and that the incremental costs may overstate the impacts of the IFR.
- *Regulatory compliance only:* For this last scenario, PHMSA assumed that only those operators of intrastate facilities subject to existing state regulations would implement safety measures contained in the API Recommended Practices. PHMSA judged this baseline as highly unlikely and considered the incremental cost to represent an upper bound of the costs that are attributable to the IFR.[42]

PHMSA concludes that the "most likely baseline conditions [are] between full compliance and partial compliance."[43] Based on PHMSA's baselines, PHMSA concludes that between 100% and 85%[44] of underground storage wells are already complying with the requirements the IFR. PHMSA goes on to use these estimates to support its overall conclusion that the costs associated

[41] OMB Circular No. A-4. Page 15.

[42] RIA, Page 4-4.

[43] RIA. Executive Summary. Page ES-3.

[44] "Under these assumptions, 2,408 wells will be subject to testing under the regulation (referred as "applicable wells" below), out of the total of 16, 991 active wells in the United States." RIA Page 5-6.

with the IFR "are unlikely to have a significant impact on the natural gas transmission and storage industry, on the demand for natural gas, or on natural gas consumers."[45]

PHMSA's Core Assumptions Supporting its Cost Estimates are Flawed.

PHMSA's estimate of costs associated with the Underground Natural Gas Storage Interim Final Rule is founded upon the following underlying assumptions:

(1) All operators that voluntarily adopt the Recommended Practices "would comply with all non-mandatory provisions in the RPs in the absence of the IFR except as justified in accordance with 192.12(a)(6)."[46]

(2) Only the requirements to conduct mechanical integrity testing of storage wells and reporting to PHMSA will impact an operator's cost to comply. All other requirements described within the IFR "are steps that operators already take to ensure the reliable and safe supply of natural gas"[47] and therefore "will require *de minimis* changes in existing practices."[48]

(3) In the nine states with existing state regulations requiring well integrity tests, operators would be required to perform no additional actions and "will not incur incremental costs as a result of the IFR".[49]

The Associations believe there are flaws in each of these assumptions. The following detailed comments describe the concerns.

(1) PHMSA Incorrectly Assumes that All Operators Voluntarily Adopting the RPs would have Complied with all Non-Mandatory Provisions

In an effort to develop baselines that represent the "way the world would look absent the proposed action,"[50] PHMSA has attempted to identify operators that have committed to voluntarily adopt the API RPs. To some degree, including voluntary actions within the baseline is appropriate. However, PHMSA has misconstrued public support for the voluntary adoption of the Recommended Practices with a commitment to complete adoption of all aspects the RPs, including non-mandatory provisions, within a limited timeframe. There are important distinctions between a voluntary commitment and the codification of a regulatory requirement.

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[45] RIA, Page 5-11.

[46] RIA. Section 4.1.3 Baseline Scenarios. Page 4-4.

[47] RIA. Section 3.1 API Recommended Practices. Page 3-2.

[48] RIA. Executive Summary. Page ES-2.

[49] RIA. Section 4.1.1 Federal and State Regulations. Page 4-1

[50] OMB Circular No. A-4. Page 15.

In the IFR, PHMSA requires that all "non-mandatory provisions (i.e., provisions containing the word 'should' or other non-mandatory language) are adopted as mandatory provisions."[51] PHMSA's assumption that all operators that have committed to voluntarily adopting the RPs would also voluntarily adopt the non-mandatory provisions is flawed.

As described in the Petition for Reconsideration filed by the Associations and reiterated in these comments, implementing all the non-mandatory provisions in the RPs is not practicable and unreasonable. It is unreasonable to assume that an operator that committed to voluntarily adopt the Recommended Practices also would voluntarily adopt non-mandatory provisions that are not practical and do not advance safety.[52]

The IFR directs operators to implement a substantive functional integrity management system that includes: data collection, documentation and review, hazard and threat identification, risk assessment, risk treatment, and periodic review and reassessment. To assume, without verification, that "between 100% and 85%" out of 124 operators of the 390 active underground storage fields have already fully integrated every element of the Recommended Practices, mandatory and non-mandatory provisions alike, to an auditable level, is purely speculative.[53]

(2) <u>PHMSA Incorrectly Assumes that Only Mechanical Integrity Testing and Reporting Would Impose Compliance Costs on Operators</u>

PHMSA states that only mechanical well integrity testing and reporting to PHMSA will impose compliance costs on natural gas storage operators. This assumption fails to recognize many of the costs associated with implementing the Recommended Practices within the timelines proposed by PHMSA.

First, the Associations believe that PHMSA has not adequately accounted for all of the required activities associated with "mechanical well integrity testing." For example, API RP 1171 Section 9.3.1: *Well Integrity Evaluation* and Section 9.3.2: *Well Integrity Monitoring*, describes the requirements for operators to perform "well integrity testing". Those requirements include:

- The operator shall evaluate the mechanical integrity of each active well, including each third party well, that penetrates the storage reservoir and buffer zone or areas influenced

[51] 49 C.F.R. 192.12(f)

[52] PHMSA states that it would expect all operators to comply with all non-mandatory provisions in the RPs in the absence of the IFR except as justified in accordance with § 192.12(a)(6). It appears that PHMSA intends to reference § 192.12(f), which provides a detailed and almost unworkable process for operators to justify not implementing a non-mandatory provision. It is unclear how operators that committed to voluntarily adopting the Recommended Practices well in advance of PHMSA's publishing the IFR would have had the foresight to predict the prescriptive language contained in §192.12(f).

[53] RIA. Section 5.1.4 Reporting Costs. Page 5-4.

by storage operations. This includes requesting and evaluating data from third-party well owner/operators

- The operator shall monitor for and evaluate the presence of annular gas by measuring and recording annular pressure and/or annular gas flow.
- The operator shall visually inspect each wellhead assembly at least annually for leaks.
- The operator shall test the operation of the master valve, wellhead pipeline isolation valve, and safety valve systems at least annually for proper function and ability to isolate the well.
- The operator should monitor for tubular corrosion and evaluate corrosion impact on well integrity and operating pressure.

However, in the RIA PHMSA describes only two actions for "well testing costs":

1. Logging costs (noise, temp, bond, casing integrity, caliper, pressure test)
2. Workover rig costs.

The Associations believe these two costs represent only one subset of requirements within an operator's obligation to, "evaluate the mechanical integrity of each active well." That being said, the Associations are concerned that even the estimates for well testing may understate costs in many circumstances. For example, PHMSA states that their estimated costs for logging include the analysis of the results by the vendor, but it does not include the activities a storage operator must perform to validate the results of the inspection. This validation can entail independent calculations of the remaining strength of the casing and other quality assurance measures. PHMSA should account for these additional activities in their assumed costs for logging. Additionally, there will be instances where operators need to perform additional downhole inspections or tests, in addition to the routine integrity testing frequency assumed in the partial compliance baseline, in order to close data gaps associated with performing risk management analysis, verifying well barrier element design and current condition, and establishing damage mechanisms and rates. Costs for these additional tests and services could include additional rig time, pressure testing equipment, tank rentals, and other equipment services. One-time costs between $16,000 and $40,000 per well, depth-averaged to approximately $24,000 per well, would be required in such cases to close the gaps. PHMSA should account for these costs in the RIA.

As another example, an operator may decide to implement a surface well site leak detection program as the result of a risk analysis for a specific well or facility. Conducting risk assessments as the basis for determining appropriate preventative and mitigative measures is an inherent requirement of the Recommended Practices. Remote methane leak detection equipment may cost approximately $20,000 per device. While a single device may be mobilized to multiple wells and facilities to take measurements on a periodic basis, there will obviously be labor costs associated with this program as well.

Additionally, PHMSA states that it "expect[s] that operators already conduct assessment, monitoring, planning, and recordkeeping activities as part of normal business operations and may simply need to incorporate the existing procedures into their program. Accordingly, PHMSA estimated the incremental burden and costs of those other RP elements to be zero for this analysis. This assumption applies to all three baseline scenarios."[54] The IFR directs operators to implement a substantive functional integrity management system that includes: data collection, documentation and review, hazard and threat identification, risk assessment, risk treatment, and periodic review and reassessment. Additional one-time and recurring costs may include: developing risk assessment and risk-based decision methodology; completing decisions and action plans required by PHMSA Advisory; self-auditing, reporting findings, developing action plans and tracking improvement. At a minimum, to accurately estimate costs, PHMSA should apply the methodology used to estimate costs for the adoption of the "mechanical well integrity testing" to the other elements within the RPs: full, partial, and regulatory compliance.

Finally, while some operators may be performing many of the functions within the RPs, PHMSA has failed to account for the costs associated with formalizing the procedures, documentation, and test data related to performing these actions. The IFR establishes a requirement not only to develop this information and an appropriate database, but to incorporate it into a form suitable for regulatory review. When an operator voluntarily performs an action, there is no obligation for them to maintain auditable procedures and records of the action. As soon as that action is a regulatory requirement, there is a burden on the operator to formalize all procedures and records.

(3) <u>PHMSA Incorrectly Assumes that Regulatory Requirements in Nine States Are Identical to the IFR Requirements</u>

Stemming from its assumption that only mechanical integrity testing of storage wells "has the greatest potential to impose incremental costs on facility operators", PHMSA limited its evaluation of the scope of existing State regulatory requirements to those state regulations associated with mechanical integrity testing. Based on this analysis, PHMSA identifies nine states[55] that have existing State requirements that mirror the requirements of the IFR and assumes that operators in those nine states will have no costs to comply with the IFR.

The Associations are concerned that PHMSA has limited the scope of their analysis of State regulations to a point that mischaracterizes the current regulatory state and the total IFR burden. As just one example, Mississippi requires operators to hydrostatically pressure test

[54] RIA. Section 5.1.3 Costs of Other RP Elements. Page 5-3.

[55] (1) Alabama (2) California (3) Illinois (4) Indiana (5) Kansas (6) Kentucky (7) Mississippi (8) Pennsylvania (9) Texas

cemented casing strings, test for mechanical integrity annually at salt caverns, and verify that all wellhead, flowlines, valves and related connections have been pressure tested to 1.5 x MAOP. However, there is no requirement in Mississippi for operators to perform "monitoring of annulus pressure" as suggested by PHMSA.[56] This requirement would only be imposed on operators by the IFR, a cost which is not accounted for in the RIA.

PHMSA Underestimates the Burden to Operators Associated with Reporting Requirements

Underground storage operators will now have several new reporting requirements with which to comply: Incident Reports (§191.15(c)), Annual Reports (§191.17(c)), Safety Related Conditions (§191.23(a)(2)), and 60-Day Notifications of Changes (§191.22(a)(1)(iv)). The Associations believe that PHMSA has understated the number of hours to complete the reports, as well as the assumed hourly cost.

The Associations support the 1-18-17 revision of PHMSA's Underground Natural Gas Storage Facility Annual Report and believe PHMSA is collecting the necessary data to execute its regulatory program. That being said, the Associations believe the annual reporting burden estimate will be higher than PHMSA anticipates. PHMSA estimates the annual reporting burden cost to the entire storage industry at less than $80,000 annually.[57] This estimate is based on an extremely low assumed average preparation cost of $61/hour, which would not account for technical or legal input, or senior management approval. The data must be uploaded, reviewed, and stored and made retrievable for reporting. Some management systems were designed to be repositories and were not developed with reporting. Companies will have to add staff to place data in reportable systems and formats. The Associations estimate that 75-125% more staff time, relative to PHMSA's estimate, will be necessary to complete this reporting, and the average hourly rate for this staff will also be 75-125% higher than PHMSA's estimate.

The Associations also believe that PHMSA burden estimates of 10 and 6 hours for each nationally standardized incident and safety-related condition reports, respectively, significantly understates the safety sensitive nature associated with the completion of each report.[58] The completion of each report requires significant coordination with several internal groups at operating companies as well as numerous external stakeholders, including: the public, state and local law enforcement, first responders, contracted metallurgists, material laboratories, etc.

PHMSA has also underestimated the reporting burden associated with the 60-day advance notice of workovers. PHMSA has estimated they will receive only 25 notices per year. The

[56] RIA in Exhibit 2-3: *Summary of State Mechanical Integrity Requirements for Natural Gas Storage.*

[57] PHMSA US Regulatory Impact Analysis at 5-5.

[58] The Associations remind PHMSA that PHMSA increased the estimated burden hours to complete Incident Reports to 12 hours in their recent Notice and Request for Comment on Incident Reports. See 81 Fed. Reg. 95294. The same Form will be used for reporting incidents at underground natural gas storage facilities.

Associations believe PHMSA should anticipate receiving hundreds of notifications each year as operators begin compliance efforts associated with the IFR.

The estimates associated with compiling and maintaining records justifying API RP deviations (8 hours to document) are also likely significantly understated. Indeed, as required by the IFR:

> *The justifications for any deviation from any provision of API RP 1170 and API RP 1171 must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility.*[59]

The process of technically reviewing and documenting the impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety will require significant time and expertise. This will require detailed analysis of the proposed deviation and likely require the drafting of separate procedure(s) to detail the operator's process to monitor the deviation and promote safety. The burden associated with compliance with this deviation process is discussed at length earlier in these comments.

PHMSA Incorrectly Assumes Full Rate Recovery

In its analysis of the economic impacts of the IFR, PHMSA makes several vast generalizations that either inaccurately assume the ability of storage operators to pass through the costs of compliance to consumers or are inappropriate for inclusion in the RIA.

First, PHMSA states that the costs incurred by SoCalGas to conduct tests "represent approximately a quarter of the total O&M costs the company reported in a 2014 regulatory filing."[60] PHMSA makes no conclusion or observations after stating this fact. PHMSA has not explained the relevance of including this fact in the RIA or whether PHMSA accounted for O&M costs into its cost/benefit analysis. Each operator is unique in both the portfolio of their assets and how they allocate O&M versus Capital spend. PHMSA's comments on this arena do not seem to be applicable for a RIA.

Second, PHMSA states that "operators of natural gas storage facilities may be able to pass through their compliance costs to their customers through increased rates for their storage services" and that the estimated costs to comply with the IFR represents "less than 0.1 percent of the average price paid by residential customers in the United States in 2015, assuming that all incremental

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[59] 49 CFR § 192.12 (a)(6).

[60] RIA. Section 5.2 Economic Impacts. Page 5-10.

storage costs are passed through to end-use customers."[61] PHMSA inaccurately assumes that storage operators will be able to pass through all IFR compliance costs. First, the storage market is very competitive. Operators often must discount their rates heavily in order to compete with each other. Storage operators cannot necessarily pass through increased compliance costs to customers due to the competitive market even if they have regulatory authority to recover such costs. However, the majority of storage capacity is subject to economic regulation and may not be able to recover costs in between rate cases. Further, the Associations do not agree that PHMSA's "less than 0.1 percent of the average price paid by residential consumers" metric to quantify the compliance costs of the IFR since it does not represent the significantly larger costs on individual storage operators.[62]

Both Cost & Benefit Estimates Must Be Evaluated Against the Same Baseline

PHMSA must evaluate both costs *and* benefits against the same baselines and the same conclusions. PHMSA seems to recognize that these analyses must align based on their footnoted-disclaimer:

> If storage facility operators currently conduct mechanical integrity tests and implement other measures contained in the API RPs or will do so without being compelled by regulations, then the associated prevention benefits (and the costs) are already reflected in the baseline and are not attributable to the IFR.[63]

However, the primary thrust of PHMSA's discussion of the benefits associated with the IFR overlooks the Agency's conclusion that it expects 85% to 100% of wells to not be impacted by the IFR. In the body of the RIA, PHMSA provides a qualitative description of the potential benefits that the codification IFR will realize. The four benefits identified by PHMSA are: (1) safety: reduction in risks due to mechanical integrity testing, (2) operating costs: detection and addressing of well integrity issues preventatively, (3) methane emission reduction: prevention of well failures due to mechanical integrity tests, and (4) regulatory certainty. The Associations believe the Recommended Practices will enhance the operations of the vast majority of underground natural gas storage facilities. Nevertheless, due to PHMSA's erroneous conclusions regarding its baseline and analysis of estimated costs, the potential benefits that PHMSA identifies as related to the IFR (as opposed to voluntary actions) can only be applied to at most 15% of the wells in operation.

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[61] RIA. Section 5.2 Economic Impacts. Page 5-10.

[62] Because PHMSA's conclusions regarding the cost to gas customers and end users are based on inaccurate assumptions, PHMSA has not adequately considered "the economic impacts of the regulations on individual gas customers," and ensuring "that the regulations do not have a significant economic impact on end users" as required by the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016." 49 U.S.C. § 60141(b).

[63] RIA. Section 6.2. Benefits of the IFR. Footnote 33. Page 6-5.

VII. MISCELLANEOUS COMMENTS

PHMSA's Use of the Interim Final Rule Process Is Not Proper

In issuing the Interim Final Rule, PHMSA invoked the "good cause" exception under the Administrative Procedure Act to bypass the statutorily required notice-and-comment process. While the Associations have supported expedient incorporation of the Recommended Practices as Federal Regulations, we are concerned about PHMSA's use of the "good cause" exception in the future. The use of IFR process, in this case, has removed one of the most important aspects of the Administrative Procedures Act: a clear and open understanding of the issues and the solutions. Many of the Associations' comments in this docket represent the same comments that would have been filed during a standard notice and comment period, and we believe this feedback would have been helpful in assuring effective implementation of the federal underground gas storage regulations.

According to PHMSA, normal notice and comment was not practicable and not in the public interest because storage facilities operating in the absence of minimum federal PHMSA safety standards are prone to corrosion.[64] Furthermore, PHMSA was concerned that its lack of enforcement authority to ensure compliance posed an "immediate threat to safety, public health, and the environment."[65] PHMSA's justification is contradicted by its own Regulatory Impact Assessment and does not reach the level of the "good cause" required to invoke the exemption.

As PHMSA appropriately recognizes, there has been widespread industry commitment to adopt the Recommended Practices. In fact, each Association has encouraged its members to adopt the Recommended Practices in advance of any federal standards.[66] PHMSA relies on this support for the Recommended Practices in evaluating the costs associated with the Interim Final Rule and suggests that 100% and 85% of active wells are voluntarily being addressed and will not be subject

[64] 81 Fed. Reg. 91865.

[65] *Id*.

[66] AGA, "Natural Gas Utilities Focused on Storage Safety: AGA Board of Directors Updates Commitment to Enhancing Safety," Feb. 22, 2016, https://www.aga.org/news/news-releases/natural-gas-utilities-focused-storage-safety.

API, "Industry Continues To Enhance Best Practices Of Natural Gas Storage Facilities," Feb. 2, 2016, http://www.api.org/news-policy-and-issues/news/2016/02/02/industry-continues-to-enhance-best-pract.

INGAA, "INGAA Board of Directors reaffirms commitment to underground gas storage integrity, supports accelerated adoption of industry standards," Feb. 11, 2016, http://www.ingaa.org/News/PressReleases/27133.aspx.

to testing under the Interim Final Rule.[67,68] PHMSA's expectations for voluntary compliance directly contradict PHMSA's invoking the "good cause" exception, which is to be "narrowly construed and only reluctantly countenanced."[69]

As noted above, PHMSA has invoked the "good cause" exception due to impracticability and the public interest. When invoking the impracticability of notice and comment, the interim final rule must respond to an imminent threat to the environment or safety or national security.[70] As PHMSA has recognized, the Agency's predecessor considered regulating underground storage facilities more than 20 years earlier, but chose not to do so.[71] PHMSA's own conscious decision not to regulate underground storage cannot now be used to support its argument that public notice and comment are impracticable. Moreover, PHMSA acknowledges that in the absence of the Interim Final Rule, operators will adopt the Recommended Practices for between 85% and 100% of wells.

Nor does PHMSA's justification meet the public interest prong of the good cause exception, which is met only in the rare circumstance when ordinary procedures would in fact harm that interest.[72] The use of the public interest prong is appropriate when notice and comment "would defeat the purpose of the proposal – if, for example, 'announcement of a proposed rule would enable the sort of financial manipulation the rule sought to prevent.'"[73] In these circumstances, it is appropriate for an agency to dispense of the notice and comment requirements "in order to prevent the amended rule from being evaded."[74] There is no concern that notice and comment would enable storage operators to evade the Recommended Practices. In fact, the opposite is true. There has been widespread support for operators to voluntarily implement the Recommended Practices

[67] The Associations' concerns with PHMSA assumptions underlying this analysis are discussed in Section VI. Nonetheless, PHMSA's expectations for compliance outside of the Interim Final Rule are directly relevant to PHMSA's reliance on the "good cause" exception.

[68] Regulatory Impact Assessment at ES-3; ES-5:6 (PHMSA believes that the most likely baseline conditions lie between full compliance – where the entire industry voluntarily implements the Recommended Practices – and partial compliance – where intrastate operators operating in states with existing standards and operators that are INGAA members or that have publicly supported the Recommended Practices voluntarily implement the Recommended Practice.).

[69] *Mack Trucks v. EPA*, 682 F.3d 87, 93 (D.C. Cir. 2012) (quoting *Util. Solid Waste Activities Grp. v. EPA*, 236 F.3d 749, 754 (D.C. Cir. 2001)).

[70] *Id*. at 93.

[71] 81 Fed. Reg. 91864.

[72] *Mack Trucks,* 682 F.3d at 95.

[73] *Id*. (quoting *Util. Solid Waste Activities Grp.*, 236 F.3d at 755).

[74] *Id*.

Definition of Underground Natural Gas Storage Facility

The IFR revises § 192.3 to include a new definition for underground natural gas storage facilities, which includes the term "solution-mined salt cavern *reservoir.*" (emphasis added). The term "reservoir" is not accurate in reference to salt caverns. The correct term is simply "a solution-mined salt cavern." This term is also used in § 192.12(a) and § 192.12(b), and should be revised for technical accuracy.

VIII. CONCLUSION

The Associations continue to support PHMSA's efforts to regulate the safety of underground natural gas storage facilities and believe that the changes recommended through these comments are necessary to ensure that the regulations are practicable, reasonable, and will enhance the safety of these facilities. In summary, the Associations request that PHMSA promptly revise its regulations for underground natural gas storage facilities as follows:

- Provide for *reasonable implementation periods*, as outlined in these comments;
    - Within 12 months, operators must have the foundational components of a functional integrity management system, including a written framework
    - Within three years, operators must have a storage functional integrity management system in place
    - Within 3 – 8 years, operators must complete underground gas storage facility risk assessments, including the baseline integrity assessments and preventative and mitigative measures warranted by the risk assessment.
- Incorporate by reference RP 1170 and 1171 *without modification* of non-mandatory provisions;
- Incorporate underground natural gas storage facilities into a new "Part 19X," *separate from Part 192*; and
- Provide additional clarification on implementation through FAQs that can be used by operators while PHMSA revises the Final Rule. Topics warranting clarification are outlined in these comments.

Respectfully submitted,

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Date: January 18, 2017

APPENDIX A

API Recommended Practice 1170
Non-Mandatory Provisions of Concern *if Made Mandatory*

The second column in the table below lists specific provisions from the Recommended Practice that are of concern to the Associations and our members if made mandatory. The language highlighted in red is non-mandatory in the Recommended Practice, but could be interpreted as mandatory in the IFR, due to § 192.12(f). The third column in the table below contains commentary intended to explain why the associated provision would be problematic as a mandatory provision in the underground natural gas storage facility regulations.

#	API Recommended Practice 1170	Comment
1	**9.2.2 Equipment – ESD Equipment** An instrument flange may be used between the wing valve and ESD valve to gather real-time pressure data when the cavern is not in use. The flange shall be rated for the same pressure as the valves (see 6.4.11 and .4.1).	Instrument flanges may be located elsewhere. This provision is intended to provide flange rating guidance *only if* in cases where the instrument flange is located between the wing valve and the ESD.
2	**9.2.3 Equipment – Flow Measurement Equipment** Each cavern should be equipped to measure flow into and out of the cavern. Flow measure is a valuable tool in facility inventory control and monitoring. These devices can be used as a check on the flow metering at metering facilities.	Please note that installing this equipment nation-wide may take 3-5 years.
3	**9.3.5.1 Instrumentation, Control and Shutdown – General** If the brine string extends into the brine, a pressure transmitter monitoring the brine string can detect an abnormally high pressure. Setting should be below the operating gas pressure (both static and dynamic) but above normal operating brine pressure. This equipment should detect a complete or partial failure of the debrining string, but may not detect small hanging string leaks or wellhead leaks.	The "may" in this section does not mean the same thing as a "shall".
4	**9.3.6 Instrumentation, Control and Shutdown – Fire and Gas Detection** This section describes a variety of alternatives for fire and gas detection and suppression equipment and includes several "should," "can," and "may" statements.	The section is intended to present operators with a variety of alternatives for fire and gas detection. If the non-mandatory provisions are made mandatory, operators may be required to install redundant equipment with minimal incremental safety benefit.

#	API Recommended Practice 1170	Comment
5	**9.6.1 Site Security and Safety – General** The operator should evaluate the safety and emergency response benefit of closed circuit television (CCTV), access control, man-down systems, barriers, intrusion detection and perimeter control.	This sentence says to evaluate the benefit of all these safety systems, but changing the "cans" to "shalls" in 9.6.2 through 9.6.11 makes all of them required, whether they provide additional safety and emergency response benefit or not.
6	**9.6.5 Site Security and Safety – CCTV** Security cameras should be used to provide real time and recorded visual monitoring of cavern wellhead, building entrances, gates, fences, and other strategic locations. Not only can they alert an operator of a real time security or safety issue, they can provide valuable information during post incident review.	Installing CCTV systems may be infeasible for certain facilities; operators should be able to evaluate the feasibility of these systems.
7	**9.6.11 Site Security and Safety – Barriers** Barriers should be installed around wellheads and other critical facilities to prevent accidental or intentional damage by vehicles and equipment. These barriers should be removable to provide space for maintenance or workover equipment.	Installing barriers around certain wellheads may be infeasible; operators should be able to evaluate the feasibility of these barriers.
8	**9.7.5.1 Training – General** Training programs are valuable tools in the ongoing development of employees to ensure that they have the knowledge and skills necessary to perform their duties safely. These programs can take the form of manuals, on-the-job training and computer based training. Training programs should address routine (normal) operations, but should also address possible abnormal operations and emergency conditions. Training programs should be reviewed periodically to measure the effectiveness of the program.	These listed choices are provided for flexibility, not duplication of effort. Changing the “can” to a “shall” makes all the listed choices required, which is redundant and costly.
9	**11.4 Abandonment – Wellbore Integrity Test** A wellbore mechanical integrity test should be performed after removal of the stored gas.	A wellbore being abandoned for reasons of failed mechanical integrity will not pass a mechanical integrity test. Therefore, this requirement as a “shall” could be detrimental to well integrity and safety.

API Recommended Practice 1171
Non-Mandatory Provisions of Concern *if Made Mandatory*

The second column in the table below lists specific provisions from the Recommended Practice that are of concern to the Associations and our members if made mandatory. The language highlighted in red is non-mandatory in the Recommended Practice, but could be interpreted as mandatory in the IFR, due to § 192.12(f). The third column in the table below contains commentary intended to explain why the associated provision would be problematic as a mandatory provision in the underground natural gas storage facility regulations.

#	API Recommended Practice 1171	Comment
1	**5.2.2 Geological Reservoir Characterization – Geological Characterization** Locations of abandoned wells, underground disposal horizons, mining, and other industrial activities should be mapped. The design should address alternative geological characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternative interpretations. Anomalous geologic features should be evaluated in terms of their potential for compromising reservoir integrity with respect to the containment of stored gas. Such features may include faulting, natural fracturing, folding, and unconformities.	As a mandatory requirement, definition should be qualified by adding "as known and available in the public domain." As a mandatory requirement, definition is needed as to the extent of the alternatives. As a mandatory requirement, definition is needed as to the extent of the evaluations.
2	**5.3.2 Engineering Reservoir Characterization – Engineering Characterization** The engineering characterization should include a review of records for all existing and abandoned wells that penetrate the formations being characterized. Existing wellbore and wellhead records should be reviewed to evaluate their current mechanical integrity in order to verify suitability for the intended design and protection of reservoir integrity. Plugged and abandoned wells should be evaluated to determine if the plugging practices, and plugging materials utilized and the placement of the plugs, effectively prevent fluid migration. Section 6 provides guidance with regard to recommended well characteristics.	As a mandatory requirement, should be qualified by adding "as known and available in the public domain."

#	API Recommended Practice 1171	Comment
	Engineering data for the characterization of hydrocarbon reservoirs should include completion and production records for the target reservoir. Records from vertically and laterally offset well completion, stimulation, and production operations within the geological characterization zone described in 5.2 should be reviewed. The quantity and quality of available data used in the engineering characterization should be evaluated to determine the need for supplemental data gathering, either prior to or during construction. The design should address alternative engineering characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternatives.	As a mandatory requirement, should be qualified by adding "as known and available in the public domain." As a mandatory requirement, definition is needed as to the extent of evaluation and the alternatives.
3	**5.4.1 Containment Assurance of Reservoir Design – General** The quantity and quality of data used in the containment assurance analysis should be evaluated to determine the need for supplemental data gathering, either prior to or during construction. The design should address alternative characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternatives.	As a mandatory requirement, definition is needed as to the extent of evaluation and the alternatives.
4	**5.4.3 Containment Assurance of Reservoir Design – Maximum and Minimum Pressure** The minimum reservoir pressure should not be designed less than historic minimum operated pressure unless reservoir geo-mechanical competency can be demonstrated. The impacts of intended minimum reservoir pressure should be accounted for in a regional review of the geologic horizon as it relates to geo-mechanical stress, reservoir liquid influx, surface facility gas cleaning and liquid handling, and liquid disposal, all of which affect the maximum cycling capacity of the storage field and can impact mechanical integrity of the facilities. The minimum reservoir pressure determination can include supplemental well drilling, coring, and laboratory analyses to provide data for the evaluation.	As a mandatory requirement, definition is needed as to the extent of evaluation. The "can" statement is conditional/opportunistic advice, not intended to apply in all situations.
5	**5.4.4 Containment Assurance of Reservoir Design – Well Penetrations** Selected plugged wells may be re-entered, examined, and replugged or monitored to manage identified containment assurance issues.	This "may" statement is conditional if observations warrant and not intended to apply in all situations.
6	**5.4.5 Containment Assurance of Reservoir Design – Supplemental Evaluations** Supplemental geological characterization may be performed for hydrocarbon reservoirs having a minimal amount of existing and available geologic data or if	These "may" statements are conditional if observations warrant and are not intended to apply in all situations.

#	API Recommended Practice 1171	Comment
	undrilled potential entrapments are indicated nearby from the initial evaluations. Additional targeted geophysical surveying or geologic data collection may be obtained.	
7	**6.3.4 Well Casing – Intermediate Casing** A well may have one or more intermediate strings of casing as needed to maintain control of subsurface conditions and to support subsequent drilling operations.	Requiring intermediate string of casing in all wells is unnecessary and costly. This may also increase drilling risk, with little to no material benefit to safety or integrity. Intermediate casing strings are not always necessary for new gas storage wells, and it may be impossible to retro-fit existing wells with an intermediate casing string. Instead, operators should use intermediate casing as needed; for example, where site-specific reservoir and/or geologic conditions warrant an intermediate casing string, or where an intermediate string is needed to maintain control of subsurface conditions and support drilling operations.
8	**6.4.4 Casing Cementing Practices – Cement Slurry Design and Controls** Cement volumes in excess of the calculated or measured requirement may be used when required to circulate cement to surface. Laboratory testing may be conducted to confirm that the cement blend meets design requirements.	Cement volumes in excess of the calculated or measure requirement are not always necessary. In many cases, operators use local cementing companies and use very basic cement blends that do not need to be tested to confirm they meet design requirements. Additionally, the service companies don't have the resources to do the testing. This may drive cementing to only the major service companies.
9	**6.4.5 Casing Cementing Practices – Cement Pumping Design** When feasible, pipe movement (i.e., either rotation or reciprocation of the casing) during hole conditioning and cement pumping should be employed to help eliminate the possibility of cement channeling. After pumping, there should be no pipe	In some cases, pipe movement could damage the seal between the pipe and caprock if the casing does not move freely and becomes stuck during this process. This may significantly increase risk of stuck pipe and/or not cementing pipe fully to

#	API Recommended Practice 1171	Comment
	movement or disturbance until the cement has been allowed to develop initial compressive strength. Backup equipment should be available in order to address possible pumping equipment failures while circulating the cement.	bottom in situations where wellbore stability above and/or within the storage zone is a possibility. As such, it is not always proper to rotate/reciprocate the pipe as this can lead to hole collapse or stuck pipe. As a mandatory requirement, this provision is problematic because an operator would generally not have back-up equipment for every single piece of equipment used for pumping a cement job. Other requirements in the RP establish sufficient standards for the final cement installation.
10	**6.5.3 Completion and Simulation – Fracture Stimulation** Monitoring may include: — annulus pressure or flow at the fracture-treated well and at nearby wells; — pressure and unusual pressure changes in the fracture-treated well and in nearby wells; — fluid composition and/or volume flowed back from the fracture-treated well; — groundwater quality and unusual quality changes in the vicinity of the fracture-treated well; — use of tracers in the fracture treatment and tracer detection logging or other logging techniques in of the fracture-treated well and/or nearby wells after the job to determine fracture location indications; and — post-treatment gas detection logs of the fracture-treated well and/or of nearby wells to investigate gas saturations behind casing and detect apparent change in saturation, if any.	This list was intended to be a recommendation of possible monitoring options, not an all-inclusive list. If required, clarification would be needed as to what constitutes a "nearby well" or how big an area in the "vicinity" of a well.
11	**6.7.2 Storage Zone Isolation** Special provisions may be necessary to isolate formations behind uncemented casing.	Uncemented casing in and of itself may not necessarily pose a significant threat or risk of loss of integrity. A site-specific risk assessment is required to determine whether a well with uncemented casing poses a greater risk than a similarly completed well that has casing fully

#	API Recommended Practice 1171	Comment
		cemented. If this provision is made mandatory, there will be significant added costs to storage operators and significant additional risk associated with related well intervention work. This should remain optional as a "may" statement to recognize that not all conditions of uncemented casing pose a significant threat to well integrity, and allow for site-specific assessments of the threat.
12	**6.8.1 Environmental, Safety, and Health – Design and Construction Safeguards** The operator should conduct an environmental impact review prior to well drilling.	Section 6.8.1's requirement to conduct an Environmental Impact Review (EIR) prior to drilling of a well could be burdensome and may not be necessary in all instances. Imposing an EIR requirement for the drilling of a new well on a well pad previously subject to an EIR would be excessive and could increase costs and extend project schedules with little to no material benefit to safety and the environment.
13	**7.2.3 Testing and Commissioning – Baseline Conditions** Baseline quality of groundwater in the vicinity of the storage operation may be tested prior to commissioning or as specified by regulatory authorities.	This may be infeasible at some storage well locations unless an existing nearby water well is accessible. This requirement would have a significant cost impacts and in many instances, would require permission from third-party landowners to construct groundwater monitoring wells where none exist.
14	**7.3.2 Reservoir Integrity Management – Monitoring and Analysis Methods** Offset hydrocarbon production or disposal operations should be monitored for unexplained flow or pressure changes.	This is problematic if made mandatory, as operators do not control access to offset production. If made mandatory, these requirements could have significant cost impacts. Operators in close proximity to third party production operations would need to acquire production, disposal, and operating pressure conditions. Unless the third party producers are

#	API Recommended Practice 1171	Comment
	In lieu of shut-in observation wells, the relationship may be based on a flowing well pressure. Subsurface correlation and gas identification logs such as gamma ray and neutron log suite may be obtained to confirm the location of gas being injected into the intended storage reservoir, as needed.	required to submit their production, disposal, and operating pressure conditions to state regulators, the data may not be available. The "may" statements are clearly conditional advice not intended to apply in all situations.
15	**7.4.2 Mechanical Integrity Monitoring – Surface Monitoring Methods** Plugged well site locations should be inspected for evidence of leakage or surface encroachments.	If mandatory, Section 7.4.2 would require monitoring of wellhead injection/withdrawal pressure and injection/withdrawal flow rate and well annulus pressures or vents. This would likely have a significant cost impacts and additional resource/staffing needs to acquire the data and/or maintain automated equipment. Conversion of wells to allow for this monitoring may take a few years to accomplish and would require that individual wells be temporarily taken out of service to complete the work. This should also be qualified by "Plugged well site locations known in the public domain and accessible..."
16	**8.4.1 Threat and Hazard Identification and Analysis – General** The operator may determine that some storage facilities are not susceptible to specific threats based on existing information, in which case the operator can provide justification and documentation for the exclusion of a specific threats.	The description of hazards and threats would not make sense if all instances of “may” were converted to “shall.”
17	**9.3.2 Well Integrity Demonstration, Verification, and Monitoring – Well Integrity Monitoring** The operator should monitor for tubular corrosion and evaluate corrosion impact on well integrity and operating pressure using risk assessment. Corrosion monitoring and evaluation should address the following:	Regarding tubular corrosion, operators should have discretion in how this requirement is achieved. For example, imposing a mandatory requirement that operators run casing inspection logs in both the tubing string and the casing string of wells would result in significant additional

#	API Recommended Practice 1171	Comment
		costs to industry, potentially with little to no material benefit to safety and integrity. If mandatory, it could also increase risks related to well workovers due to the invasive nature of effective inspection of both the tubing string and the casing string (both strings should be logged independently of one another). It is not feasible to always conduct the activities specified in this provision. If mandatory, this requirement could be problematic when adjacent wells are owned by third parties with no legal requirement for them to allow the storage operator to inspect their well. As a mandatory requirement, this should be qualified with "for well site locations known in the public domain and accessible..."
	The operator should identify the recorded location of plugged wells that penetrate the storage reservoir, within the buffer zone, or areas influenced by storage operations and inspect each well site for evidence of gas or other fluid flows to surface. The operator should inspect adjacent active and plugged wells during or following a stimulation or hydraulic fracturing treatment to verify integrity maintenance when a well located within the reservoir area and buffer zone is being treated at pressures exceeding maximum storage reservoir pressure.	Regarding plugged and abandoned wells, it may not be possible to locate all plugged wells – depending upon availability of historical records – and obtain access to plugged wells on private lands. If mandatory, this provision would likely result in impacts to costs and resources, and ongoing access for periodic inspections may not be possible without specific agreements and/or consent of the landowner on which the well is located. As a mandatory requirement, this should be qualified with "for well site locations known in the public domain and accessible..."

#	API Recommended Practice 1171	Comment
	The operator may obtain compositional analysis of water samples taken from the storage reservoir or other formations for potential comparison to water that may accumulate within the wellbore during storage operations to identify possible well integrity problems.	Regarding water samples as a mandatory requirement, this would impose a significant burden on operators for additional sampling and analysis of water that may accumulate in the wellbore of any storage well. In other words, if a wellbore is suspected of having any water in it, the operator would be obligated to obtain a fluid sample for analysis and compare it to the analysis of other samples from the reservoir or other formations. This would increase operating costs and potentially the need for additional resources to gather and analyze the data with little or no material benefit to storage integrity.
18	**9.4.2 Reservoir Integrity – Buffer Zone** The operator should review both the lateral and vertical components of the buffer zone as additional geologic or operational data become available, to determine if the boundaries continue to protect the integrity of the reservoir.	Determination of the need to define vertical buffers is location-specific depending on varied and complex issues such as geological, subsurface rights, and historical issues. Older facilities may never have had vertical buffers defined in a regulatory filing, such filings may require significant time and resources to draft and be granted, and there may not be a need to define the vertical buffers.
19	**9.4.3 Reservoir Integrity – Third-Party Activity** New third-party wells located within the lateral and vertical buffer zone should be drilled and completed in a manner to isolate the storage reservoir as recommended by the storage operator. Third-party wells located within the lateral and vertical buffer zone being plugged and abandoned by the third part should be plugged in a manner to isolate the storage reservoir and protect its integrity.	These requirements would apply to the third party drilling, not the storage operator. While underground gas storage operators would support this action by third-party drillers, third parties may have no statutory or legal requirements to cooperate with the storage operator. Section 8, Table 2, has suggestions of P&M measures that could be pursued to mitigate this threat.

#	API Recommended Practice 1171	Comment
		Section 9.4.3 would require operators to work with third-party or regulatory agencies to foster implementation of those preventative and mitigative measures. If made mandatory, this would impose a significant burden on storage operators. While storage operators could identify preventative and mitigative measures that should be implemented to protect the integrity of the storage operation, they likely have no authority to mandate compliance with such measures (unless the third party willingly enters into a contractual agreement). If this requirement is adopted, the regulatory agency charged with oversight of drilling activities should explicitly impose these requirements on the third party.
20	**9.4.4 Reservoir Integrity – Observation Wells** The operator should use observation wells around, above, or below the reservoir to monitor pathways of potential communication and/or migration.	Observation wells are one of the integrity management "tools in the toolbox" and are not applicable to every situation. For example, not every spill point requires an observation well if it can be shown that degraded reservoir quality, large elevation relief from the lowest known gas to the spill point, or other such factors make it extremely unlikely to be a potential gas migration path. This could have a significant impact on storage operators in terms of costs for drilling additional, and potentially unnecessary, observation wells.
21	**9.4.5 Reservoir Integrity – Gas Composition** The operator should obtain compositional analysis of gas samples taken from available shallower zones or casing annuli for comparison to gas analysis from the storage reservoir to identify potential gas leakage or gas migration pathways.	This item should not be interpreted to require gas samples from every annulus of every well or every shallow zone, but only in those cases where potential gas leakage has been determined to have occurred. Additionally, making this provision mandatory may establish a requirement to drill

#	API Recommended Practice 1171	Comment
		observation wells (see comments above regarding observation wells).
22	**9.5.3 Gas Inventory Assessment – Hydrocarbon Reservoir Methodology** For a storage reservoir converted from a depleted hydrocarbon reservoir, the operator should use methods of inventory assessment based on reservoir operating characteristics, including but not limited to: - Conducting semiannual low and high inventory (generally in the spring and fall) storage pressure surveys to obtain a representative reservoir pressure at low and high inventories - Performing material balance studies using the reservoir pressure and inventory data collected during the semiannual surveys - Monitoring shut in well pressure trends for indication of gas migration - Using key indicator wells to monitor the pressure relative to inventory	As a mandatory requirement, if the intention is that this be a formal material balance evaluation for purposes of inventory verification, then every 6 months is much too frequently. A comparison of inventories at similar pressures acquired semiannually would be fine, as this is much less burdensome than a material balance study.
22	**9.5.5 Gas Inventory Assessment – Additional Actions** The operator should account for wellbore liquid levels, where wellbore liquid levels are suspected to be present, when analyzing wellhead and/or bottom hole pressure data for reservoir integrity with necessary corrections made for elevation and fluid gradients.	Bottom hole pressure equipment is not readily available in some areas. As a mandatory requirement, this should be qualified by adding "necessary equipment is available to discover and verify liquid levels."
23	**9.6.2 Deviations** Well pressure and/or flows should be monitored for deviations from expectations to alert operators of potential wellbore integrity issues.	This is consistent with sound engineering practice. However, there would likely be significant cost impacts to operators who do not currently have the capability to monitor pressure and/or flow rate at individual wellheads. There may also be additional resource/staffing needs to acquire the data and/or maintain automated equipment. Conversion of wells to allow pressure and/or flow monitoring may take a few years to accomplish and would require that individual wells be temporarily taken out of service to complete the work.

#	API Recommended Practice 1171	Comment
24	**9.6.3 Flow Erosion** The operator should monitor casing and wellhead component wall thickness at facilities where the conditions are suitable for erosion to occur. The frequency of wall thickness monitoring should be evaluated using risk assessment.	As a mandatory provision, this may be problematic because it may be duplicative of efforts required elsewhere in the Recommended Practice. For new facilities, Section 5.4.6 establishes the requirement for operators to consider "Design factor to protect the mechanical integrity of the storage facility," including an "analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures."
25	**10.2.1 Site Security and Safety – General** this requirement may be addressed through the use of a site access control plan.	This "may" statement is conditional advice clearly not intended to apply in all situations.
26	**10.2.2 Site Security and Safety – Site Security and Safety** The operator should implement and maintain site security and safety measures. The operator should evaluate local and site-specific conditions in developing the security measures and may include requirements for: - security check points; - barricades such as bollards, jersey barriers, or concrete impediments; - industrial-type steel mesh fencing; - locking gates; - security lighting; - security cameras; - alarm systems; - windsocks; - wellhead enclosures; - valve handles removed, or valves secured; and, - other means of preventing unauthorized entry or operation of storage facilities. The operator may employ additional measures to enhance site security and safety based on an analysis of site specific factors.	This list was intended to be a recommendation of site security and safety measures to consider, not an all-inclusive list of requirements.

#	API Recommended Practice 1171	Comment
27	**10.3.1 Ingress and Egress – Roads** Lease or well roads should be maintained in a condition that permits personnel and equipment access to the well.	As a mandatory requirement, this should be qualified to allow for weather related and other exceptions. Many existing wells do not have roads, making it a "shall" would be interpreted as well roads as being mandatory. Installing roads will detract funds from more critical requirements to reduce overall risk. Some sites will require legal intervention in order to construct which will take much longer than a year to litigate. Roads to all observation wells are not necessary.
28	**10.3.2 Ingress and Egress – Fences and Enclosures** Ingress or egress of the site may be controlled by fences or enclosures	Most storage facilities do not currently have a fence or other enclosure around each well. As a mandatory requirement, this would have a significant impact on storage operators in terms of cost, resources, and operations. Wells are often located on private property owned by third parties. Installation of fencing or other types of enclosures would require approval from the landowner, who may not be willing to consent. The need for fencing or other types of enclosures at individual well sites and other storage facilities should be determined based on a site-specific risk assessment.
29	**10.4.2 Signage – Additional Information** The operator can add other information or signage to enhance site security and safety; such additional information could include applicable location information or warnings for areas containing potentially hazardous, flammable, or noxious vapors	This "can" statement is conditional/operational advice clearly not intended to apply in all situations.
30	**10.6.2 Emergency Preparedness/Emergency Response – Training** The training can include mock drills and participation in table-top exercises at regular intervals. The table-top exercises or mock drills can include civil emergency responders to enhance understanding and successful incident response.	These "can" statements are intended to provided operators with alternatives for conducting drills.
31	**11.2.1 Procedures – Construction, Operation, and Maintenance Procedures**	Section 11 becomes a very prescriptive section if the "shoulds" are replaced with "shalls." The

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		"should" statements give guidance on what may be included in the procedure. When these become shall statements, the level of detail required to be in the procedure is much more prescriptive than envisioned by the RP 1171 authors, and will require more time and more detail. This will create more burden and make it difficult to complete all of the required detailed procedures in the timeframe (1 year) specified in 192.12 section (d). Section 11.2.1 addresses the imposition of minimum requirements for construction including drilling and other well entry work, reservoir integrity monitoring and management, O&M, emergency response, control room communications and responses, personnel safety, safety management systems, and site-specific procedures determined to be necessary by the operator. It will take time and resources to develop these documents.
32	**11.12.1 Training – Training Requirements** The operator should provide training for personnel responsible for operating, maintaining, and monitoring storage wells and reservoirs in accordance with their duties and responsibilities.	Please note this must be a multi-year process. Developing training plans and documentation for all of these activities will be a substantial effort that is not feasible within 12 months.
33	**11.12.3 Training – Supervisory Personnel** Specific job requirements may require the company person or persons directly responsible for the work being conducted ("supervisors") to be located on site while the work is being conducted (see 6.10).	As a mandatory statement, PHMSA needs to specific what "specific requirement" include
34	**11.12.4 Training – Contractor Personnel** The operator may use contractor personnel in the performance of constructing, operating, maintaining, and monitoring duties associated with storage wells and	As a mandatory requirement, this would now require operators to use contract personnel for these monitoring duties. In-house monitoring is often the better option when available.

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	reservoirs. This subsection provides recommendations regarding training of contractor personnel. The operator should define minimum qualification or experience requirements for contractors performing work on their storage wells and reservoirs. The operator should develop a method to verify contractor training, which may include a review of the contractor's safety training programs, worksite checks of individual contractor employee training, or operator observation of contractor work performance.	 Please note that this is a multi-year process. Developing training plans and documentation for all of these activities will be a substantial effort that is not feasible within 12 months.
35	**11.13.1 Records – Documentation** The operator shall maintain records to document establishment of and compliance with procedures as required in Section 11. Records may be kept in an appropriate format (paper or electronic). The integrity of the records, especially electronic, should be verifiable. Records should include superseded procedures.	Section 11.13.1 indicates that records should include superseded procedures. However, while this may be implementable on a go-forward-basis, operators should not be required to produce and document outdated procedures that may have been used in the past to perform well work and other maintenance procedures.
36	**11.13.2 Records – Training Records** Company personnel training records should include: — identification of the trained individual; — identification of the training and methodology of training provided; and — date(s) training was completed by the individual. Contractor Training Records—The operator should retain documentation of the contractor training review (see 11.12.4).	Please note that this is a multi-year process. Developing training plans and documentation for all of these activities will be a substantial effort that is not feasible within 12 months.