SoCalGas-5

Exhibits to Prepared Reply Testimony of Tim Hower and Charlie Stinson of MHA Petroleum Consultants (March 20, 2020)

I.19-06-016

ALJs: Hecht/Poirier

Date Served: March 12, 2021

Ex. I - 1

DATA RESPONSE TO SOUTHERN CALIFORNIA GAS COMPANY IN I.19-06-016:

1. Identify the sponsoring witness(es) for SED's OPENING TESTIMONY.

The sponsoring witness for SED's opening testimony is Ms. Margaret Felts.

Ex. I - 2

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- UNGS IFR
- UNGS IFR (PDF)
- Full Interagency Task Force Final Report "Ensuring safe and relaible Undergroun...
- DOE Fact Sheet on Interagency Task Force Recommendations
- 49 CFR Part 192
- UNGS FAQs
- Pipeline Safety: Safety of Underground Natural Gas Storage Facilities; Petition...

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Underground Natural Gas Storage

This site is administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA). It provides information concerning Safe Operations of Underground Gas Storage Facilities for Natural Gas.

Interim Final Rule

On December 19, 2016, PHMSA published in the Federal Register an interim final rule (IFR) that revises the Federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This IFR responds to Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015. This IFR incorporates by reference two American Petroleum Institute (API) Recommended Practices (RP): (1) API RP 1170, "Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage," issued in July 2015, and (2) API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," issued in September 2015.

Gas Leak at Aliso Canyon Underground Natural Gas Storage Facility

On October 23, 2015, a massive gas leak occurred at the Aliso Canyon Underground Natural Gas Storage Facility near Los Angeles, California. In the wake of that incident, an interagency task force was established that consisted of representatives from the Department of Energy (DOE), Department of Transportation (DOT), the Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission (FERC), the Department of Commerce (DOC), the Department of Health and Human Services (HHS), and the Department of the Interior (DOI), and from state and local governments. The Task Force included premier scientists, engineers and technical experts from across the DOE complex, including five National Labs, the other Federal departments, and the Executive Office of the President.

The Task Force issued a report in October 2016 intended to help reduce the risk of future similar incidents.

Advisory Bulletin ADB-2016-02

On February 11, 2016, in response to the Aliso Canyon Underground Natural Gas Storage Facility incident, PHMSA issued Advisory Bulletin ADB-2016-02 to owners and operators of underground pipeline and storage facilities regarding the safe operation of underground storage facilities for natural gas [Docket No. PHMSA-2016-0016].

The bulletin was issued to remind all owners and operators of underground storage facilities used for the storage of natural gas, as defined in 49 CFR part 192, to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment. The bulletin was intended to inform operators about recommended practices and to urge operators to take all necessary actions, including but not limited to those set forth in the bulletin, to prevent and mitigate breach of integrity, leaks, or failures at their underground storage facilities and to ensure the safety of the public and operating personnel and to protect the environment. Operators should have comprehensive and up-to-date processes, procedures, mitigation measures, periodic assessments and reassessments, and emergency plans in place to maintain the safety and integrity of all underground storage wells and associated facilities whether operating, idled, or plugged. Operators must adhere to applicable State regulations for the permitting, drilling, completion, and operation of storage wells.

All owners and operators of underground storage facilities used for the storage of natural gas, as defined in 49 CFR part 192, should review their operating, maintenance, and emergency response activities to ensure properly and adequately the overall integrity of the facilities. Operators should identify the potential of

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facility leaks and failures caused by corrosion, chemical damage, mechanical damage, or other material deficiencies in piping, tubing, casing, valves, and associated facilities. Operators must also consider the importance of reviewing the location and operations of shut-off and isolation systems and reviewing and updating emergency plans as necessary.

PIPES Act of 2016

On June 22, 2016, the PIPES Act of 2016 was enacted (Public Law No. 114-183). With regard to Underground Gas Storage Facilities, the PIPES Act of 2016 (the Act) amends 49 U.S.C. section 60101(a) to define "underground natural gas storage facility" as "a gas pipeline facility that stores natural gas in an underground facility, including—(A) a depleted hydrocarbon reservoir; (B) an aquifer reservoir; or (C) a solution-mined salt cavern reservoir." The Act requires PHMSA to issue, within two years of passage, "minimum safety standards for underground natural gas storage facilities." In addition, the Act expressly allows states to adopt more stringent safety standards for intrastate facilities, if such standards are compatible with the minimum standards prescribed in section 12 of the Act. In order to implement the safety standards, the PIPES Act imposes a "user fee" on entities operating underground storage facilities.

Additional Information

- May 2019 presentation to American Gas Association
- August 2018 presentation to Southern Gas Association
- February 2018 presentation to the Louisiana Mid-Continent Oil & Gas Association.

Menu links on the left of this page provide additional information regarding the safe operation of underground natural gas storage facilities. This site will be updated as new information becomes available.

Related Links

- PHMSA Underground Natural Gas Storage IA Question Set
- UNGS IFR
- UNGS IFR (PDF)
- Full Interagency Task Force Final Report "Ensuring safe and relaible Underground Natural Gas Storage"
- DOE Fact Sheet on Interagency Task Force Recommendations
- 49 CFR Part 192
- UNGS FAQs
- Pipeline Safety: Safety of Underground Natural Gas Storage Facilities; Petition for Reconsideration (PDF)
- Pipeline Safety Underground Natural Gas Storage Grants

Last updated: Thursday, February 27, 2020

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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, and 195

[Docket No. PHMSA–2016–0016; Amdt. Nos. 191–27; 192–126; 195–103]

RIN 2137–AF22

Pipeline Safety: Safety of Underground Natural Gas Storage Facilities

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: The Pipeline and Hazardous Materials Safety Administration is publishing this final rule to amend its minimum safety standards for underground natural gas storage facilities (UNGSFs). On December 19, 2016, PHMSA issued an interim final rule (IFR) establishing regulations in response to the 2015 Aliso Canyon incident and the subsequent mandate in section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016. The IFR incorporated by reference two American Petroleum Institute (API) Recommended Practices (RPs): API RP 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage'' (First Edition, July 2015); and API RP 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' (First Edition, September 2015). The IFR required each provision in the API RPs to apply as mandatory (*i.e.,* each ''should'' statement would apply as a ''shall'') unless an operator provides written justification for not implementing the practice, including an explanation for why it is impracticable and not necessary for safety. Based on the comments received to the IFR and a petition for reconsideration, PHMSA has determined that the RPs, as originally published, will provide PHMSA with a stronger basis upon which to base enforcement than the IFR. This final rule also addresses recommendations from commenters and a petition for reconsideration of the IFR by modifying compliance timelines, revising the definition of a UNGSF, clarifying the states' regulatory role, reducing recordkeeping and reporting requirements, formalizing integrity management practices, and adding risk management requirements for solution-mined salt caverns.

DATES: This final rule is effective on March 13, 2020. The Director of the Federal Register approved the incorporation by reference on January 18, 2017.

FOR FURTHER INFORMATION CONTACT:

Technical questions: Byron Coy, Senior Technical Advisor, by telephone at 609–771–7810 or by email at *byron.coy@dot.gov.*

General information: Ashlin Bollacker, Technical Writer, by telephone at 202–366–4203 or by email at *ashlin.bollacker@dot.gov.*

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I. Executive Summary

A. Purpose of This Final Rule

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is amending the pipeline safety regulations applicable to underground natural gas storage facilities (UNGSFs). PHMSA is amending the UNGSF regulations in response to comments and recommendations received on its interim final rule (IFR) published on December 19, 2016 (81 FR 91860). The IFR implemented PHMSA's authority to regulate UNGSFs and the Congressional mandate in section 12 of the PIPES Act (Pub. L. 114–183) to establish minimum safety standards for depleted-hydrocarbon reservoirs, aquifer reservoirs, and solution-mined salt caverns used for the storage of natural gas.[1] Congress issued the mandate to PHMSA following a large-scale natural gas leak at the Aliso Canyon UNGSF in Southern California on October 23, 2015. The mandate required PHMSA to establish minimum safety standards for UNGSFs within two years of the PIPES Act issuance on June 22, 2016. To meet the mandate's deadline—and address the urgent need for safer storage of natural gas—PHMSA published the IFR with a 60-day comment period. The IFR went into effect on January 18, 2017.

Since that time, PHMSA has considered public comments and a petition for reconsideration of the IFR and is modifying the minimum safety standards for UNGSFs in this final rule accordingly. PHMSA has also further reviewed the Final Report of the Interagency Task Force on Natural Gas Storage Safety[2] to ensure any amendments in this final rule are consistent with the Task Force's recommendations to PHMSA.[3] As detailed in this final rule, PHMSA believes these changes will reduce regulatory burdens and reduce costs for industry and gas consumers while sustaining safety and protecting the environment.

B. Summary of the Major Provisions

Consistent with the IFR, this final rule maintains the incorporation by reference of American Petroleum Institute (API) Recommended Practices (RPs) 1170 and 1171 (the RPs) as the basis of the minimum safety standards in 49 CFR part 192. API RP 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage''[4] has recommended practices for solution-mined salt cavern facilities used for natural gas storage and covers facility geomechanical assessments, cavern well design and drilling, solution mining techniques,

[1] For a description of these storage types and other basic information about underground natural gas storage, see *https://www.eia.gov/naturalgas/storage/basics/.*

[2] ''Ensuring Safe and Reliable Underground Natural Gas Storage,'' Final Report of the Interagency Task force on Natural Gas Storage Safety; October 2016. See *https://www.energy.gov/downloads/report-ensuring-safe-and-reliable-underground-natural-gas-storage.*

[3] In addition to their comments on the IFR, on March 17, 2017, the State of Texas and the Texas Railroad Commission petitioned the U.S. Court of Appeals for the Fifth Circuit for review of the IFR under 49 U.S.C. 60119(a). *See State of Texas* v. *PHMSA,* No. 17–60189 (5th Cir. Mar. 17, 2017). On April 24, 2017, the court granted INGAA and AGA's motions to intervene in the litigation. On July 19, 2017, the court granted a joint motion to hold the petition for review in abeyance pending the issuance of this final rule.

[4] API Recommended Practice 1170 ''Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage (First Edition, July 2015).

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and operations, including monitoring and maintenance practices. API RP 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' [5] has recommended practices for natural gas storage in depleted oil and gas reservoirs and aquifers, and focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operation, monitoring, maintenance, and documentation practices. Both RPs describe ways to maintain the functional integrity of design, construction, operation, monitoring, maintenance, and documentation practices for UNGSFs. The RPs contain numerous provisions that use the term ''shall'' to denote a minimum requirement necessary to comply with the RP. The RPs also use non-mandatory terms such as ''should,'' ''may,'' and ''can'' to denote a recommendation that is advised, but not required.

This final rule amends the IFR in six primary ways. First, PHMSA adopts the RPs without modification to the non-mandatory terms. In the IFR, PHMSA adopted the RPs by modifying the non-mandatory provisions (*i.e.,* statements containing ''should'' and other non-mandatory terms) as mandatory requirements (*i.e.,* ''shall''). PHMSA provided that operators could deviate from the modified statements by providing a justification in their procedure manuals as to why the provision was ''not practicable and not necessary for safety'' at their specific facility. Accordingly, with this final rule, PHMSA also no longer requires operators to provide written justifications as to why they would not have performed a ''should'' provision.

Second, this final rule is formalizing requirements and deadlines for operators to develop and implement their integrity management (IM) programs and to conduct their baseline risk assessments for UNGSFs. As noted by commenters and petitioners, the API RPs function as an IM system for UNGSFs, which requires more time to implement than the IFR allowed. After considering these comments and recommendations, PHMSA is relaxing the timeline for completing initial assessments of the reservoirs, caverns, and wells. PHMSA discusses these new requirements and deadlines in Section III–C, ''Compliance Timelines.''

Third, this final rule includes a requirement for solution-mined salt caverns to follow the same risk management practices as depleted-hydrocarbon reservoirs and aquifers that apply to the physical characteristics and operations of the facility (*i.e.,* follow section 8 of API RP 1171). Since the publication of the IFR, PHMSA has observed that many operators of solution-mined salt caverns are voluntarily using section 8 of API RP 1171 to supplement the risk management practices in section 10 of API RP 1170. While most salt-cavern UNGSFs have a risk-management program in place, section 8 of API RP 1171 provides more prescriptive practices than API RP 1170 for how an operator must develop, implement, and document a program to manage risks that could affect the functional integrity of the storage operation. Extending the applicability of the recommended practices in section 8 of 1171 closes a potential critical safety gap for salt-cavern storage facilities and may prevent future failures at these facilities. PHMSA has codified this practice in the final rule to ensure consistency across all UNGSF facilities.

Fourth, PHMSA is narrowing the scope of reportable events and changes at facilities. In addition to annual data reporting and National Registry information, the IFR required operators to notify PHMSA of certain changes and events and their facilities, such as incidents and safety-related conditions. Since the IFR, PHMSA received many notifications for routine maintenance activities, which was not the intent of the regulation. Operators are not required to notify PHMSA of regular maintenance. To make this clear, PHMSA is limiting notification of changes to a facility 60 days prior to the following events: (1) All plugging or abandonment activities (regardless of costs), and (2) construction or maintenance that requires a workover rig and costs $200,000 or more. PHMSA is also applying an emergency exemption to the 60-day notification requirements, which PHMSA overlooked in the IFR.

Fifth, this final rule is revising the definition of an ''underground natural gas storage facility.'' The PIPES Act amended 49 U.S.C. 60101(a) to define an ''underground natural gas storage facility'' as ''a gas pipeline facility that stores natural gas in an underground facility, including—a depleted hydrocarbon reservoir, an aquifer reservoir; or a solution-mined salt cavern reservoir.'' The IFR incorporated a modified version of this definition in part 192. Part 192 covers the transportation of natural gas by pipeline. PHMSA discovered through the public comments on the IFR that the placement of the definition in part 192 created questions for operators as to where a gas pipeline facility ended, and regulations for a UNGSFs began. To remedy this confusion, PHMSA is revising the definition of an ''underground natural gas storage facility'' to exclude other components of a gas pipeline or gas pipeline facility covered elsewhere in part 192, and eliminate any potential overlap. PHMSA discusses the revised definition and the reason for keeping it in part 192 later in this document.

Sixth, PHMSA is changing the name of the reporting portal to the ''National Registry of Operators'' (formerly the ''National Registry of Pipeline and LNG Operators''). Additionally, PHMSA is revising the name of the online portal's web address from ''*http://opsweb.phmsa.dot.gov*'' to ''*https://portal.phmsa.dot.gov*.'' These changes are throughout parts 191, 192, and 195.

C. Costs and Benefits

Consistent with Executive Order (E.O.) 12866, PHMSA has prepared a Regulatory Impact Analysis (RIA) that includes an assessment of the benefits and costs of this final rule, as well as reasonable alternatives. PHMSA published an RIA to accompany the IFR as well. This final RIA incorporates input from public comments on the IFR and the initial RIA. PHMSA has issued the final RIA concurrently with this final rule, and it is available in the docket (PHMSA–2016–0016).

The annualized cost savings for this final rule, relative to the IFR, are estimated to be $11 million, applying a 7 percent discount rate. The benefits of this final rule come from making permanent the safety measures in the IFR and RPs 1170 and 1171, which API and other stakeholders developed to prevent leaks and blowouts before they occur. The safety measures adopted through the IFR and this final rule will prompt operators to undertake or hasten preventive and mitigative measures, as well as IM actions, such as mechanical integrity tests, that will reduce the probability of releases.

The IFR reduced the likelihood and magnitude of catastrophic or operational natural gas releases by promoting safer practices through the incorporation of the recommended practices into the pipeline safety regulations. This final rule continues to require these same practices. For example, operators are required to assess the mechanical integrity of each storage well, evaluate the likelihood of failures at these wells, and determine the next steps to remedy conditions that could precede the

[5] API Recommended Practice 1170 ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' (First Edition, September 2015).

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failures. Operators are also required to incorporate safety best practices when designing and constructing new wells, which could further prevent catastrophic failures.

This final rule also adds a requirement for all solution-mined salt caverns to follow the risk management practices in section 8 of RP 1171. Per the IFR, PHMSA had only required operators of solution-mined salt caverns to follow the risk management practices in section 10 of RP 1170. The language in section 10, requires operators to take a ''holistic and comprehensive approach to monitoring cavern integrity,'' without providing specifics as to how to implement that approach. Post-IFR, during preliminary inspections, PHMSA observed operators of solution-mined salt caverns applying the framework of the risk management practices in section 8 of RP 1171. While RP 1171 applies to depleted hydrocarbon reservoirs and aquifer reservoirs, it offers a framework for risk management and monitoring that is translatable to other types of underground storage facilities. PHMSA expects that other operators of solution-mined salt caverns would benefit from a more specific framework for implementing the ''holistic and comprehensive approach to monitoring cavern integrity'' required in section 10 of 1170.

Additionally, codifying the requirement for these operators to follow both section 8 of RP 1171 and section 10 of RP 1170 ensures consistent safety requirements across all UGS facilities. This change may cause those operators who were not already (voluntarily) applying API RP 1171 as a framework for monitoring cavern integrity to undertake stronger risk management practices, which could ultimately reduce the risk of an incident. However, PHMSA considers this action part of the baseline requirements to follow a ''holistic and comprehensive approach to monitoring cavern integrity'' already prescribed through the IFR. As a result, PHMSA does not expect an additional financial burden to operators beyond that already in place through the IFR.

The IFR required operators to provide a written justification for each non-mandatory provision of the RPs that they did not perform. This final rule removes that recordkeeping burden on operators. Operators experience cost savings from the removal of requirements associated with deviations from the RPs, including technical reviews by subject matter experts and recordkeeping burdens, and reductions in the notifications burden.

II. Background

A. Overview of Underground Natural Gas Storage

Underground storage of natural gas plays a critical role in the nation's energy independence and reliability. Notably, having a surplus of natural gas provides a buffer from the seasonal variations in supply and demand, creating price stability for customers. Over the past ten years, natural gas storage has increased 16 percent, prompted, in part, by significant growth in domestic shale-gas production.

There are three principal types of underground natural gas storage fields, each with different geological characteristics and capabilities that govern their suitability for storage. The three types are depleted hydrocarbon reservoirs, aquifer reservoirs, and solution-mined salt caverns. Depleted hydrocarbon reservoirs are the most common type of storage, representing approximately 80 percent of the total working gas capacity in the United States. As the name implies, these facilities are repurposed from previous oil or gas production and converted to gas storage fields.[6] Aquifer reservoirs are natural water-bearing formations, also converted to gas storage, and represent roughly 9 percent of the total working gas capacity in the United States. Solution-mined salt caverns (salt domes) are geological formations that leached out of salt deposits. These facilities represent only about 10 percent of the total working-gas capacity but provide high withdrawal and injection rates relative to their working gas capacity.[7]

Of the 403 active UNGSFs in the United States, approximately 60 percent of the facilities are interstate, and 40 percent of the facilities are intrastate.[8] The total storage capacity at these fields was 9,236 billion cubic feet (Bcf), and the total working gas capacity was 4,815 Bcf. Facilities identified as interstate represented 63 percent of total storage capacity and 65 percent of working gas capacity.

Interstate UNGSFs serve interstate facilities, such as providing storage for interstate gas transmission pipelines.[9] These types of storage facilities commonly receive surplus gas from interstate pipelines during warmer months and then send it back into the product stream during colder winter months. Since these UNGSFs serve interstate facilities and PHMSA has exclusive pipeline safety jurisdiction over the design, construction, operation, and maintenance of interstate gas pipeline facilities, the standards in this final rule will affect all interstate UNGSFs.

Intrastate UNGSFs, on the other hand, are facilities that provide gas storage for intrastate pipelines, most notably local gas distribution companies (LDCs). These storage facilities serve intrastate pipelines that are contained entirely within a particular State and that do not fall within the jurisdiction of the Federal Energy Regulatory Commission (FERC). As discussed more fully below, these intrastate ''gas pipeline facilities'' are generally subject to the IFR and this final rule. Intrastate UNGSFs may continue to also be subject to State regulations provided that: (a) The otherwise applicable State regulation does not conflict with the Federal minimum safety standards established in the final rule, and (b) the applicable State authority has filed a certification with PHMSA to participate as a full State partner under the new Federal program and to receive Federal funding through PHMSA.

B. Underground Storage Incidents and Regulatory History

While rare, serious incidents at underground storage facilities have occurred. For instance, on April 7, 1992, an uncontrolled release of highly volatile liquids from a salt-dome storage cavern near Brenham, Texas, formed a heavier-than-air gas cloud that exploded. Three people died in the accident, with an additional 21 people treated for injuries at area hospitals. Property damage from the accident exceeded $9 million.

Following its accident investigation, the National Transportation Safety Board (NTSB) published pipeline safety recommendation No. P–93–9 regarding underground storage. Recommendation P–93–9 asked PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA), to develop safety requirements for storage of highly volatile liquids and natural gas

[6] Energy Information Administration (EIA). 2015. ''The Basics of Underground Natural Gas Storage.'' November 16, 2015. Retrieved from *http://www.eia.gov/naturalgas/storage/basics/* (Accessed March 2019).

[7] Total working gas capacity percentages do not sum to 100 percent due to rounding.

[8] PHMSA's 2018 annual report data show 403 active underground natural gas storage fields in the United States as of 2017, distributed across 31 states.

[9] Under 49 U.S.C. 60101(a)(6), an ''interstate gas pipeline facility'' (including an interstate UNGSF) is defined as ''a gas pipeline facility—(A) used to transport gas; and (B) subject to the jurisdiction of the [FERC] under the Natural Gas Act (15 U.S.C. 717 *et seq.*).'' The term ''transporting gas'' is defined in § 60101(a)(21) as ''the gathering, transmission, or distribution of gas by pipeline, or the storage of gas, in interstate or foreign commerce . . .''

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in underground facilities, including a requirement that all pipeline operators perform safety analyses of new and existing underground geologic storage systems to identify potential failures, determine the likelihood that each failure will occur, and assess the feasibility of reducing the risk.[10]

In response to the NTSB's safety recommendation, RSPA held a public meeting [11] to determine what actions it should take, if any, regarding the regulation of underground storage of natural gas and hazardous liquids. The participants expressed mixed views on whether RSPA should begin to regulate "downhole" pipe and underground storage. Most participants spoke favorably of industry safety practices and State regulation but saw no immediate need for Federal regulatory action.

On July 1, 1997, RPSA issued an advisory bulletin (ADB–97–04) to inform UNGSF owners and operators of the availability of guidelines for the design and operation of underground storage facilities. Specifically, the advisory bulletin pointed to the safety standards guide from the Interstate Oil and Gas Compact Commission (IOGCC) [12] and API as appropriate for use by pipeline operators and State regulatory agencies. The IOGCC guide provided safety standards for the design, construction, and operation of gas storage caverns. API had published guidelines for the underground storage of liquid hydrocarbons. RP 1114, "Design of Solution-Mined Underground Storage Facilities," June 1994, provided basic guidance on the design and development of new solution-mined underground storage facilities. RP 1115, "Operation of Solution-Mined Underground Storage Facilities," September 1994, provided guidance on the operation of solution-mined underground hydrocarbon liquid or liquefied petroleum gas storage facilities.

Another catastrophic natural gas leak happened in January 2001 after a wellbore failed at the Yaggy storage field near Hutchinson, Kansas. The natural gas migrated nine miles underground, where it eventually surfaced through abandoned wells. Once at the surface, the natural gas exploded, killing two people and destroying two businesses.[13] After a month, the flares burned off, with the ultimate loss of 143 million cubic feet (MCF) of natural gas from the storage field.

These incidents at UNGSFs alerted operators and regulators to consider assessing the safety of these facilities. By 2012, API had begun developing additional guidance for the safety of UNGSFs. API developed RP 1170 and 1171 over several years, based on input from many industry stakeholders, including regulators such as PHMSA, FERC, and five State regulatory agencies, as well as the API Midstream Group. In July 2015, API issued RP 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage." API RP 1170 provides recommendations and requirements for geo-mechanical assessments, cavern well design and drilling, solution mining techniques, operations and maintenance procedures, and practices for salt caverns. In September 2015, API issued RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," which focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operations and maintenance procedures, monitoring, and documentation practices. The RPs appropriately recognize the variety and diversity of UNGSFs used throughout the United States and are not limited to addressing facilities in a single State, basin, geological setting, or well type.

C. Aliso Canyon Incident

Shortly after the publication of the industry safety standards RP 1170 and RP 1171, another major UNGSF incident occurred. On October 23, 2015, Southern California Gas Company (SoCalGas) discovered a leak that manifested into the largest methane leak from a natural gas storage facility in U.S. history. Well SS–25 in the Aliso Canyon storage field, located in Los Angeles County, California, leaked for nearly four months until it was permanently sealed on February 17, 2016. While SoCalGas attempted to plug the leak, residents in nearby neighborhoods experienced health symptoms consistent with exposure to the odorants (mercaptans) added to natural gas and residual components from previous oil production in the field. The incident temporarily displaced more than 5,000 households from their homes, according to the Aliso Canyon Incident Command briefing report issued on February 1, 2016, although some sources place the number of related households at approximately 8,000.[14]

The leak at Aliso Canyon ultimately released approximately 5.7 Bcf of natural gas into the atmosphere, translating to 109,000 metric tons [15] of methane, a potent greenhouse gas, as well as numerous other pollutants.[16] Additional reports identified other potential health effects that lasted even after the well was sealed. A report by the Los Angeles County of Public Health suggests that the continued health symptoms may be due to contaminants in indoor air and dust.[17] As of December 31, 2016, SoCalGas and its parent company, Sempra Energy, recorded estimated costs of $913 million to control the release, monitor air emissions, relocate residents, and cover legal and other expenses.[18] The singular well that failed in the Aliso Canyon accident (SS–25) had originally been drilled in 1953 and was re-purposed for natural gas storage in 1972. The age of this well is not unusual. Per data from the American Gas Association (AGA), approximately 60 percent of active storage wells are located in fields that were activated before 1960.

The Aliso Canyon incident created serious energy-supply challenges for the region and prompted public concerns about the safety of UNGSFs, including the extent and effectiveness of Federal and State oversight. On February 5, 2016, PHMSA issued an advisory bulletin (ABD–2016–02), identifying specific minimum actions that operators of UNGSFs should take, in addition to the recommendations of ADB–97–04,

[10] National Transportation Safety Board, Pipeline Accident Report PAR–93/01 (Nov. 4, 1993).

[11] (Docket PS–137, 59 FR 30567, June 14, 1994).

[12] Interstate Oil and Gas Compact Commission, "Natural Gas Storage in Salt Caverns: A Guide for State Regulators." (IOGCC Guide), 1995.

[13] Allison, M. Lee, 2001, The Hutchinson Gas Explosions: Unraveling a Geologic Mystery, Kansas Bar Association, 26th Annual KBA/KIOGA Oil and Gas Law Conference, v1, p3–1 to 3–29.

[14] For example, see KPCC news report on August 4, 2016, "Cost estimate of Aliso Canyon gas leak hits $717 million". *http://www.scpr.org/news/2016/08/04/63268/cost-estimate-of-aliso-canyon-gas-leak-hits-717-mi/.*

[15] CARB estimates that the incident resulted in a total emission of 99,650 ± 9,300 metric tons of methane (CARB, 2016a) and seeks mitigation of 109,000 metric tons.

[16] California Air Resources Board (CARB), 2016; County of Los Angeles Public Health.

[17] Ibid. CARB.

[18] Of the $913 million of costs, approximately 60 percent is for the temporary relocation program (including cleaning costs and certain labor costs). Other estimated costs include amounts for efforts to control the well, stop the Leak, stop or reduce the emissions, and the estimated cost of the root cause analysis being conducted by an independent third party to investigate the cause of the Leak. The remaining portion of the $913 million includes legal costs incurred to defend litigation, the value of lost gas, the costs to mitigate the actual natural gas released, the estimated costs to settle certain actions and other costs. The value of lost gas reflects the replacement cost of volumes purchased through December 2017 and estimates for purchases in 2018. As of mid-January 2018, SoCalGas has replaced all lost gas. SoCalGas adjusts its estimated total liability associated with the Leak as additional information becomes available." (SoCalGas/Sempra, 2018).

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API RP 1170, API RP 1171, and the IOGCC Guide. The 2016 advisory bulletin recommended that operators begin reviewing their operating, maintenance, and emergency response activities and apply the new RPs accordingly.

On July 14, 2016, PHMSA held a public meeting to discuss potentially extending its regulations to include transportation-related UNGSFs. PHMSA heard from a diverse group of stakeholders, including State regulators, emergency responders, and residents, including those impacted by the Aliso Canyon incident. PHMSA concluded that it should take action to incorporate by reference API RP 1170 and API RP 1171 into part 192. The RPs describe a range of measures that UNGSF operators should undertake to ensure the safe operations of their facilities. The RPs also include construction, maintenance, IM, security, and emergency response procedures.

D. The PIPES Act of 2016

The Aliso Canyon incident prompted broader public concerns as to how to prevent similar UNGSF accidents in the future. Congress addressed these concerns in two sections of the PIPES Act, enacted on June 22, 2016 (Pub. L. 114–183). Section 12 of the PIPES Act required PHMSA to issue minimum safety standards for all UNGSFs within two years of enactment. The statute defines an ''underground natural gas storage facility'' as a ''gas pipeline facility that stores natural gas in an underground facility.'' Because title 49 United States Code (U.S.C.) 60101(a) already defines ''gas pipeline facility'' as ''a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation,'' PHMSA interprets the PIPES Act as directing it to regulate only those UNGSFs that store natural gas incidental to transportation.

The PIPES Act requires that in issuing minimum safety standards for UNGSFs, PHMSA must: (1) Consider consensus standards for the operation, environmental protection, and integrity management of underground natural gas storage facilities; (2) consider the economic impacts of the regulations on individual gas customers; (3) ensure that the regulations do not have a significant economic impact on end users; and (4) consider the recommendations of the Aliso Canyon natural gas leak task force established under section 31 of the PIPES Act of 2016.

The Secretary of Transportation (the Secretary) delegated this responsibility under chapter 601 of title 49 U.S.C. to the PHMSA Administrator (49 CFR 1.97). PHMSA fulfilled this mandate by publishing the IFR on December 19, 2016. The PIPES Act provides that states may adopt additional or more stringent safety standards for intrastate UNGSFs if such standards are compatible with these Federal regulations.

E. Interagency Task Force

In addition to section 12 of the PIPES Act, Congress included a second mandate, section 31, directing the Department of Energy (DOE) to establish an Interagency Task Force on Natural Gas Storage Safety to perform an analysis of the Aliso Canyon events and make recommendations to reduce the occurrence of similar events in the future. PHMSA and DOE co-led the effort. The Task Force established several working groups, comprised of premier scientists, engineers, and technical experts from the Executive Office of the President and various Federal agencies. The working groups examined three key areas:

- The integrity of natural gas wells at storage facilities;
- The public health and environmental effects from natural gas leaks; and
- The nation's vulnerability to reduced energy reliability in the event of future leaks.

In October 2016, the Task Force issued its final report on natural gas storage safety and made 44 recommendations to operators and regulators. The main recommendation to PHMSA was to incorporate existing industry consensus standards, API RP 1170 and 1171, into part 192 of the regulations in an enforceable manner, and consider supplementing the regulations with recordkeeping and reporting requirements as necessary. The Task Force recommended that operators develop comprehensive risk-management plans that addressed risks based on their potential severity and probability of occurrence. These plans should document an operator's risk-management strategy, identify risks, define responsibilities among stakeholders, assess risks, and take appropriate action to reduce risks to well integrity.

The Task Force's report also highlighted growing concerns regarding the age of the nation's natural gas storage infrastructure. For example, wells reflect material, technology, and design factors that may have been appropriate at the time they were constructed, but may not meet design criteria for wells drilled today. Over time, corrosion, other environmental processes, and mechanical stresses from the injection and withdrawal of natural gas can impact well integrity. Wells in depleted oil fields may have been designed for lower operating pressures than what they may be subject to now. Many of these wells were designed without redundant barriers to reduce the risk of gas migration. One of the lessons from the Aliso Canyon incident is that wells without redundant barriers present higher risks because they have a single point of possible failure that may be extremely difficult to shut off or kill.

F. Interim Final Rule

On December 19, 2016, PHMSA issued the IFR that satisfied section 12 of the PIPES Act, exercising the agency's statutory authority to regulate underground natural gas storage facilities. The IFR amended the pipeline safety regulations found at 49 CFR parts 191 and 192, to address critical safety issues related to ''downhole'' UNGSF facilities, including wells, wellbore tubing, casing, and wellheads (81 FR 91860). Additionally, the IFR added a definition of ''underground natural gas storage facility'' to §§ 191.3 and 192.12 and applied reporting requirements to operators of UNGSFs similar to those applicable to operators of other gas pipeline facilities, including annual reports, incident reports, reports of major construction and organizational changes, and registration with the National Operator Registry.

Effective January 18, 2017, all UNGSFs, both intrastate and interstate, now had to meet the minimum standards outlined in RPs 1170 and 1171 and were subject to inspection by PHMSA or a PHMSA-certified State entity. The IFR made each provision in the RPs 1170 and 1171 mandatory unless the operator documented a technical justification why compliance with a provision was not practicable and not necessary for safety. Operators were required to incorporate the RPs into their written operations, maintenance, and emergency response program manuals following § 192.605. PHMSA, or a certified State partner, would review any of the operators' justifications and its procedure manuals during compliance inspections.

After publishing the IFR, PHMSA took significant steps to educate the regulated community on the new requirements, to promote a better understanding of issues concerning integrity assessments of UNGSFs and the implementation of the RPs. The first action was to publish frequently asked

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questions (FAQs).[19] The FAQs provided guidance on the procedures, implementation plans, and schedules that operators should have in place to meet the requirements in the applicable RPs. For example, while the IFR did not provide clear timelines for operators to complete the integrity assessments required by the RPs, the FAQs provided a recommended implementation schedule. With the issuance of this final rule, PHMSA will revise the FAQ guidance material to reflect these regulations as amended.

In preparation for the development of inspection and enforcement efforts, PHMSA subject matter experts conducted preliminary site assessments at a cross-section of UNGSFs from May to July of 2017.

Additionally, PHMSA has instituted a program for training Federal and State inspectors on the new minimum Federal standards affecting all UNGSF facilities. As it promulgates this final rule, PHMSA is prepared to modify the program through future regulations and guidance to keep pace with evolving consensus safety standards, academic research, and lessons learned from the firsthand experience of its inspectors, State regulators, affected stakeholders, and the public.

G. Petition for Reconsideration

On January 18, 2017, the American Gas Association (AGA), American Petroleum Institute (API), American Public Gas Association (APGA), and Interstate Natural Gas Association of America (INGAA) (the ''Associations'') jointly filed a petition for reconsideration of the IFR. AGA represents local energy companies, as well as residential, commercial, and industrial natural gas customers. API is a national trade association representing the oil and natural gas industry, including gas pipelines and UNGSF operators. APGA is a national, non-profit association of publicly-owned natural gas distribution systems. INGAA is an industry trade association representing interstate natural gas pipeline companies in the United States.[20]

In the petition, the Associations affirmed their support for PHMSA's efforts to regulate the safety of UNGSFs. They reminded PHMSA that the Associations and their members had supported PHMSA's incorporation by reference of the RPs as Federal standards for natural gas storage. They stressed the importance of adopting the RPs to advance the safety of the pipeline transportation system but asked PHMSA to revise the IFR to incorporate RP 1170 and API RP 1171 without modification and to provide for reasonable implementation periods. The Associations stated that the changes requested in the petition would ensure that PHMSA's regulations would be practical, reasonable, and effective.

On June 20, 2017, PHMSA issued a notice stating that it would provide an answer to the petition in the final rule (82 FR 28224). PHMSA announced that in the interim, it would not issue any enforcement citations for failure to meet any of the non-mandatory provisions of the RPs that the IFR converted to mandatory ones until one year after the issuance the final rule. PHMSA has considered the recommendations from the Associations and is answering their petition in this final rule.

III. Comment Summaries and PHMSA's Responses

A. Introduction

PHMSA received 82 comments and one petition for reconsideration in response to the IFR issued on December 19, 2016. PHMSA provided a 60-day comment period initially but re-opened it on October 19, 2017 (82 FR 48655), for an additional 30 days to provide all interested parties with the opportunity to comment on the IFR and the merits and claims of the petition for reconsideration. During the initial 60-day comment period, PHMSA received 28 comments. PHMSA received 54 additional comments during the re-opened 30-day comment period, but only 14 of those 54 related to this rulemaking.[21] Half of those 14 comments were from organizations that had already submitted comments during the initial, 60-day comment period.

PHMSA discusses and responds to these comments and recommendations in sections B through J, below. For organizational purposes, PHMSA has grouped comments by subject matter. Below is a list of entities who submitted comments on the IFR.

- Atmos Energy
- Consumers Energy
- Dow Chemical Company (Dow)
- ENSTOR
- Environmental Defense Fund (EDF)
- Gas Free Seneca
- Gas Piping Technology Committee (GPTC)
- Geological Maps Foundation
- GPA Midstream Association (GPA)
- Hilcorp Alaska
- Hon. Brad Sherman, representing 30th Congressional District of California
- Independent Petroleum Association of America (IPAA)
- Joint Comment from American Gas Association (AGA), the American Petroleum Institute (API), the American Public Gas Association (APGA), and the Interstate Natural Gas Association of America (INGAA)
- Joint Comment from the States First Initiative, the Interstate Oil and Gas Compact Commission (IOGCC), and Groundwater Protection Council (GWPC)
- Louisiana Mid-Continent Oil and Gas Association (LMOGA)
- Michigan Department of Environmental Quality
- New York State Department of Environmental Conservation
- Northern Natural Gas
- Pacific Gas and Electric Company (PG&E)
- Private Citizens (50)
- Railroad Commission of Texas
- Southern California Gas Company (SoCalGas)
- Texas Pipeline Association
- TransCanada
- Vectren

B. Incorporation by Reference of API Recommended Practices 1170 and 1171

In the IFR, PHMSA required operators to treat non-mandatory language in the RPs as mandatory. For each provision modified by the IFR, an operator could deviate from the recommended practice by providing in its procedures manual a technical justification for each deviation. Under the IFR, PHMSA required an operator to use a subject matter expert to review and document the technical justification, and a member of the operator's executive leadership was required to review, approve, and document the date of approval. During routine inspections, PHMSA would review an operator's justifications for deviating from the modified provisions.

1. Comments on PHMSA's Modification of the RPs

Many commenters disagreed with PHMSA's modification of the non-mandatory provisions of the RPs. Almost all commenters supported the Associations' position concerning the

[19] ''Underground Natural Gas Storage: FAQs.'' (revised April 2017) *https://primis.phmsa.dot.gov/ung/faqs.htm.*

[20] On April 17, 2017, INGAA withdrew from the petition for reconsideration, but the other three Associations have remained as petitioners.

[21] The 40 comments that PHMSA deemed not relevant appear to have been submitted anonymously using automated technology (*i.e.,* bots). While these comments raise generalized issues related to environmental protection (climate change, renewable/alternative energy, streamlining environmental reviews, etc.), the comments do not connect their generalized statements to any of the specific provisions of this rulemaking, such that they would become meaningful to the issue of the safety of underground natural gas storage systems.

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conversion of the non-mandatory provisions in RPs 1170 and 1171 to mandatory. Generally, commenters supported the need for consistent minimum safety standards for all UNGSFs and supported regulations to that effect. Those same commenters asserted that if PHMSA adopted the IFR without modification, it would impose burdensome and impracticable requirements on operators.

In their petition, the Associations stated that ''changing the [RPs] in this manner is not necessary for enforcement, nor is it practicable or reasonable.'' The Associations stated their belief that there was ''no regulatory justification for making all 'non-mandatory' provisions 'mandatory,' '' and requested that PHMSA eliminate this provision. Further, the Associations said that although the RPs use both non-mandatory and mandatory language, this alone does not affect their enforceability. They said that the RPs contain enough mandatory provisions to ensure enforceability. The Associations used the mandatory provisions in section 8 to demonstrate that the RPs are broad enough, as written, to be enforced. Additionally, they stated that the non-mandatory statements in the RPs do not compromise the enforceability of the broad requirements imposed on operators through the mandatory provisions.

The Texas RRC stated that it strongly disagreed with PHMSA's modification of the RPs. The Texas RRC noted that the wholesale adoption of RPs would lead to confusion and have unintended consequences. It said that if PHMSA kept the modification to the non-mandatory provisions in the final rule, it would undermine the integrity of the original RPs, ultimately making them even more difficult to enforce. Lastly, the Texas RRC stated that, while the IFR allowed an operator to deviate from particular provisions, PHMSA did not provide a process or timeframe by which the agency would review, approve, or deny the operator's alternative procedure(s). The Texas RRC requested that, if PHMSA chose to incorporate the RPs as modified by the IFR, the agency should add a review process and timeline for consideration of requests for deviation from the modified provisions.

ENSTOR Operating Company, LLC (ENSTOR), asserted that converting all non-mandatory provisions in the RPs to mandatory requirements would undermine the risk-based approach of the RPs and create unintended results. ENSTOR stated that PHMSA's conversion of non-mandatory RP statements in sections 8, 9, 10, and 11 of RP 1171 to mandatory provisions could establish statutorily-impermissible retroactive requirements, such as requiring the use of observation wells drilled around, above, and below a reservoir. ENSTOR added that PHMSA ''can simply require operators to discontinue any deviations that the agency does not agree with,'' and ''there are no standards to guide the agency's determination and no means for review or appeal of a denial of an operator deviation.''

Some operators stated that the process for justifying deviations from a specific non-mandatory RP would be time-intensive, expensive, and unworkable for many operators. LMOGA stated that requiring technical documentation for each deviation was excessive since the RPs themselves already identified the non-mandatory practices as applicable on a case-by-case and site-specific basis. Further, LMOGA noted that the IFR required each deviation must be ''technically reviewed and documented by a subject matter expert to ensure that there will be no adverse impact on the facility. . . .'' LMOGA argued that the term ''subject matter expert'' was vague and imprecise.

EDF said that PHMSA would not be reviewing an operator's technical justifications until after the operator had already deviated from a recommended practice and contended that this could allow harmful activities to persist until an inspection took place at the facility. Further, EDF said that operators might make significant financial commitments in reliance on unapproved deviations, only to see their decisions overturned after the fact, without practical recourse, by PHMSA. Regarding the IFR's treatment of non-mandatory provisions as mandatory, EDF stated its preference would be for PHMSA to adopt the API RPs but examine the non-mandatory provisions of the API RPs on a provision-by-provision basis to determine if any should be made mandatory, and adopt additional regulatory requirements to fill in potential gaps in the final rule.

TransCanada, which participated in the development of RP 1171, stated that the inclusion of both ''should'' and ''shall'' in the RPs reflected a deliberate, iterative, consensus-building effort that resulted in the selection of those specific words. TransCanada went on to say that it would not be prudent to make such recommendations mandatory because doing so could lead to a misplaced effort to document exceptions when operators should be focusing on the imperatives of IM and the development of effective procedures.

2. PHMSA's Response to Comments on Its Modification of the API RPs 1170 and 1171

After considering the petition for reconsideration and public comments, PHMSA is accepting the recommendation to adopt the RPs 1170 and 1171 as originally written by API, without modification. When drafting the IFR, PHMSA needed to provide an immediate and reasonable means by which it could begin regulating UNGSFs, while, at the same time, implementing sections 12 and 31 of the PIPES Act. As discussed earlier, section 12 of the PIPES Act required PHMSA to consider existing industry standards and recommendations from the Interagency Task Force (created by section 31) as the basis for its pending regulations. In its 2016 report, the Interagency Task Force recommended that PHMSA consider ''incorporating existing industry-recommended practices API RP 1170 and 1171 into the part 192 regulations, and they should be adopted in a manner that can be enforced.'' Historically, PHMSA has successfully incorporated by reference many industry standards, guidance, and recommended practices in lieu of developing its own regulations.

After additional review, PHMSA has determined that adopting the RPs as originally published by API would still provide significant benefits for safety, the environment, and public health but would be much easier for the regulated industry and the public to understand and for PHMSA to interpret and enforce. The non-mandatory provisions in the RP provide operators with guidance for optional considerations based on the features and characteristics of individual storage facilities. However, the RPs still require all operators to develop policies and procedures to ensure the functional integrity of UNGSFs and to inspect and verify the operational integrity of these facilities on a site-specific basis and will provide PHMSA with a stronger basis upon which to base enforcement than the IFR.

As the Associations pointed out in their petition for reconsideration, the existence of ''non-mandatory provisions in the RPs does not affect their overall enforceability.'' Throughout the RPs, there are many broad mandatory provisions that operators of UNGSFs must implement, using a range of options considered in accompanying non-mandatory provisions. The non-mandatory provisions provide operators with illustrations, examples, or choices of action for how to achieve compliance with the mandatory provisions. Because these non-mandatory provisions are

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closely tied to the mandatory provisions that operators must meet, any non-mandatory provision remains enforceable to the extent that it is necessary, in the context of a particular operator or facility, to ensure compliance with a mandatory provision in the Recommended Practice.

Based on the petition for reconsideration, the post-IFR comments received, as well as its experience with the application and enforcement of similar consensus standards and recommended practices, PHMSA believes that adopting the RPs in their original published form, will accomplish the goal of the IFR, which was to improve safety. The means of achieving this goal was to establish, for the first time, minimum Federal safety standards that would require operators of all UNGSFs to meet certain basic, uniform, and risk-based policies and procedures as outlined in the RPs. In evaluating regulatory alternatives, PHMSA did consider adopting a portion of the ''should'' provisions to identify and address any potential gaps, but PHMSA ultimately decided not to because the Agency does not have sufficient information to identify whether there are ''should'' statements that are, on average, more or less practical and necessary at each site, and thus would be more or less likely to cause operators to seek deviations. In light of this factor and the comments received, PHMSA is convinced that treating the non-mandatory provision as written in the RPs is the better course of action because it adds clarity to the provisions which should help improve compliance while providing at least an equivalent level of safety as the IFR.

The IFR and this final rule are PHMSA's first effort to establish a national regulatory program for UNGSFs. This program includes features such as basic reporting requirements, Federal and State inspections, and a Federal-State partnership that will enable States to go beyond the RPs by adding additional or more stringent requirements. As the agency and the industry gain experience implementing this new regulatory program, they will learn what improvements need to be made. If experience shows that the RPs do not provide an adequate level of safety for certain activities or risks, PHMSA will consider the need to modify the regulations, as appropriate.

C. Compliance Timelines

The IFR required that UNGSFs constructed before July 18, 2017, meet all operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping provisions of the applicable RPs within one year from the effective date of the IFR, *i.e.,* January 18, 2018. Specifically, existing UNGSFs using a solution-mined salt cavern for storage were required to meet the requirements of RP 1170, sections 9, 10, and 11, and operators of existing UNGSFs using a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage were required to meet the requirements of RP 1171, sections 8, 9, 10, and 11, by the same date.

Following the publication of the IFR on December 19, 2016, PHMSA published FAQ guidance (April 2017) to assist operators in applying the RPs. The FAQs included a suggested timeline for operators to complete the risk analysis and baseline assessments for the requirements in the IFR.

1. Comments on the Compliance Timelines

PHMSA gave operators one year from the effective date of the IFR to comply with the IFR. Commenters stated that the timeline for compliance provided in the IFR was unreasonable, and PHMSA's expectations for operators were unclear. Commenters requested that the final rule adopt phased-in compliance timelines, as PHMSA has done in previous rulemakings. Most commenters recommended that PHMSA follow the timelines published in its Underground Natural Gas Storage FAQs (April 2017).

Most industry commenters asked that PHMSA modify the compliance timelines to break it up into phases and extend the overall schedule, similar to what the FAQs outlined, which suggested that operators complete the baseline integrity assessments of each storage field within three to eight years. These commenters agreed that the FAQ's timelines for baseline integrity assessments were realistic and that any shorter timeframe was unrealistic and impracticable. They supported including clear, phased-in timelines in the final rule. Most said it would take longer than 12 months to implement all aspects of the RPs fully and that the PHMSA should extend the compliance deadline.

The Associations requested that the final rule incorporate the risk assessment and integrity-management timelines currently outlined in the FAQs.[22] The Associations doubted that PHMSA had intended to require operators to implement all actions under the applicable sections of the RPs within one year. In their comment, the Associations spoke of an operator that had recently implemented the RPs at its facility. The operator reported that it took over 18 months to gather the subject matter experts and complete the integrity plans and operating procedures. The Associations added that operators should expedite the implementation of preventive and mitigative measures for high-risk or imminent-risk facilities, as identified by their risk assessments.

Similarly, TransCanada stated that it was impractical to implement the IFR by January 18, 2018, and asked that PHMSA clarify in the final rule what the agency expected operators to have achieved by January 18, 2018, and beyond. TransCanada agreed, with certain reservations, that baseline risk assessments could begin within one to two years of the effective date of the final rule. They also agreed that three to eight years was enough time to complete risk assessments for all individual wells at UNGSFs.

2. Response to Comments on the Compliance Timelines

PHMSA is accepting the commenters' recommendations to reconsider the compliance timelines in the final rule. These timelines are similar to the ones published PHMSA's Underground Natural Gas Storage FAQs (April 2017). Below is a summary of the compliance timelines for implementing a UNGSF program.

Deadline for Written Procedures

Consistent with the IFR, operators must prepare and follow written procedures for the operations, maintenance, and emergency management and response activities outlined by the applicable RPs. However, this final rule removes the requirement in the IFR that these procedures be incorporated into an operator's existing procedural manuals required for gas pipelines under § 192.605. Instead, the final rule replaces this provision with a similar requirement that UNGSF operators develop written procedures for carrying out the final rule and maintain and update them in a similar fashion as required by § 192.605 for gas pipelines. In the final rule, the new requirement is in a new paragraph exclusive to UNGSFs under § 192.12.

Accordingly, operators must establish and follow written procedures for implementing their UNGSF programs. By January 18, 2018, all operators with

[22] ''Underground Natural Gas Storage FAQs,'' issued by PHMSA in April 2017.

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facilities constructed on or before July 18, 2017, must have established and put into service procedures for operations, maintenance, and emergency preparedness. All other operators must have these procedures in place prior to commencing operations. Operators must also establish an interval for reviewing and updating these written procedure manuals, not exceeding 15 months, but at least once each calendar year.

Integrity Management Framework

By January 18, 2018, all operators with facilities constructed on or before July 18, 2017, must have established a framework for IM under the IFR. All other operators must have this framework in place prior to commencing operations. An initial framework means a written explanation of the mechanisms or procedures the operator will use to implement each program and API RP to ensure compliance with this final rule. These procedures, implementation framework, and schedules do not need to be fully fleshed out but must be sufficient for putting the program in place over the long term. PHMSA expects that each operator's implementation framework and schedules will evolve into a more detailed, comprehensive, and robust program as the operator's program matures. An operator must make continual improvements to the program.

The IM framework for a UNGSF must include:

- A plan for developing and implementing each program element;
- An outline of the procedures to be developed;
- The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures;
- A plan for how staff will be trained in awareness and application of the procedures;
- Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and
- A plan for how to incorporate information gained from experience into the IM program on a continuous basis.

Timelines for Conducting Risk Assessments

By four years after the effective date of this final rule, each operator must have completed baseline risk assessments for 40 percent of all its wellbores, wellheads, and associated components. Operators should generally prioritize assessments on higher-risk wells first, based on a matrix of identified threats, hazards, and the likelihood of their occurrence. Operators must complete baseline assessments of all reservoirs and caverns by the same date. By seven years after the effective date of this final rule, operators must have completed baseline risk assessments for all remaining wellbores, wellheads, and associated components. This implementation period is similar to the one published in PHMSA's Underground Natural Gas Storage FAQs (revised April 2017).[23]

D. Placement of Underground Storage Regulations in a New Part for Title 49 of the 49 CFR

The IFR added requirements in parts 191 and 192 for UNGSFs that cover reporting, recordkeeping, design, construction, and operation and maintenance procedures and practices. Before the IFR, there were no Federal regulations pertaining directly to UNGSFs. While part 192 already covered much of the surface piping at these facilities, up to the wing-valve assemblies on the wellhead at UNGSFs served by pipeline, PHMSA had not previously issued rules for the actual wellhead or ''downhole'' portion of these facilities.

1. Comments Requesting a New Part for Title 49 of the CFR

The IFR amended parts 191 and 192 to add underground natural gas storage regulations. For several reasons, commenters requested that PHMSA create a new ''part 19x'' in subchapter D of title 49 of the CFR that would contain regulations exclusively for underground storage. Generally, their interest was in differentiating the requirements for UNGSF from those requirements for other types of regulated gas facilities.

The Associations and some operators recommended that PHMSA remove the underground storage regulations from part 192 and place them in a new part under subchapter D in 49 CFR. They asserted that moving UNGSF regulation to a new part in the pipeline safety regulations would clarify the application of the regulations both now and in future rulemakings. The commenters stated that because the existing definitions of pipeline and pipeline facility in § 192.3 were so similar to the definition of underground natural gas storage facility (also in § 192.3) that it was unclear how to apply the regulations.

The Associations also expressed concern that because the IFR placed the underground storage regulations in part 192, operators might mistakenly apply the engineering regulations specific to other pipeline facilities to UNGSFs—or vice-versa. The RPs contain design, construction, and IM practices for UNGSFs that the Associations believed are considerably different from the practices for other pipeline facilities outlined throughout part 192. They provided examples of regulations that, if misapplied, might result in unsafe practices. The Associations asserted that PHMSA could avoid these potential conflicts by placing the UNGSF regulations in a new part under 49 CFR subchapter D, separate from part 192.

Several commenters, including Dow Chemical Company, claimed that adding underground storage regulations to part 192 would generate confusion. Specifically, commenters said that the IFR was unclear as to which sections of part 192 applied to UNGSFs and which ones to other gas pipeline facilities. The GPTC expressed the view that the definition of underground natural gas storage facilities in § 192.3 overlapped with the existing definitions of pipeline facilities and transmission pipelines and that it believed PHMSA intended to expand the regulatory scope of parts 191 and 192 to UNGSFs. However, GPTC implied that the overlap between the new definitions and the new regulations' placement in part 192 would create confusion as to the applicability of the RPs to pipeline facilities already regulated under other subparts of part 192.

Similarly, PG&E requested that the final rule revise the pipeline safety regulations to specify which parts of 49 CFR subchapter D applied to underground natural gas storage, instead of providing clarification through agency guidance materials (*e.g.,* FAQs). They stated that PHMSA historically had not incorporated FAQs addressing additional programs, such as ''Integrity Management,'' ''Drug and Alcohol Testing,'' and ''Gathering Lines,'' into regulatory language. PG&E stated that it believed this practice would leave operators at risk of being forced to comply with requirements that did not appear in regulatory language. Therefore, PG&E encouraged PHMSA to clarify § 192.12 by adding an exclusion for the subparts of part 192 that would not apply to underground natural gas storage. Other commenters shared this view and expressed concern that PHMSA would attempt to use FAQs or similar guidance documents instead of properly promulgated regulations.

2. Response to Commenters' Request for a New Part

Section 60101(a)(21) defines the term ''transporting gas'' as ''the gathering, transmission, or distribution of gas by

[23] *https://primis.phmsa.dot.gov/ung/faqs.htm.*

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pipeline, or the storage of gas, in interstate or foreign commerce.'' The statute specifically lists the ''storage'' of natural gas as one component of ''transporting gas.'' Since all PHMSA's substantive regulations pertaining to the transportation of natural gas are in part 192, PHMSA believes the UNGSF regulations also belong in part 192.

Along with the public comments, PHMSA reviewed recommendations from the Interagency Task Force and a petition for rulemaking from INGAA. The Task Force recommended that PHMSA incorporate the RPs into part 192, with supplemental recordkeeping and reporting procedures as necessary. The IFR noted that INGAA had petitioned PHMSA on January 20, 2016—while the Aliso Canyon accident was still ongoing—to incorporate the RPs into part 192. Because UNGSFs are part of the broader natural gas transportation systems, part 192 is the most logical place for the new substantive regulations. Incorporating the requirements into parts 191 and 192 also subjects UNGSF operators to the requirements of part 190, for enforcement and regulatory procedures, and part 199, for drug and alcohol testing. Therefore, PHMSA had adopted these recommendations and by adding the UNGSF regulations in parts 191 and 192.

PHMSA agrees that the language in the IFR resulted in a certain level of ambiguity about the applicability of § 192.12 to other gas pipeline facilities and, vice versa, the applicability of other existing regulations to UNGSFs. PHMSA has addressed this issue by making two changes in this final rule. First, PHMSA is adding an introduction to § 192.12, which provides that the section contains minimum requirements for UNGSFs. This introduction means to clarify that § 192.12 only applies to UNGSFs and no other pipeline facilities. Second, the final rule also modifies the definition of a UNGSF to eliminate any potential overlap with other gas pipeline facilities covered elsewhere in part 192.

PHMSA also agrees with the commenters that the FAQs are guidance documents to help operators understand and implement rulemakings. FAQs are not the basis for PHMSA's enforcement of the rule. However, they can and should be used to clarify or explain PHMSA's interpretation of the scope and applicability of the regulation. For example, while not explicitly stated in the preamble or the amendatory language of the IFR, PHMSA explained through FAQs that operators of UNGSFs are subject to regulation under 49 CFR part 199, ''Drug and Alcohol Testing.'' Any operator of a ''pipeline facility'' that is subject to any subset of the part 192 regulations is required to test covered employees for the presence of prohibited drugs and alcohol. PHMSA also explained in the FAQs that operators of UNGSFs were not required to comply with the ''Qualification of Pipeline Personnel'' requirements contained in subpart N of 49 CFR part 192. The FAQs explained that operators must comply with the training requirements in API RP 1170 (section 9.7.5) or API RP 1171 (section 11.12), dependent upon the type of storage field. Both API RP sections describe general training parameters and specifically identify the need to train personnel for normal, abnormal, and emergency conditions. Additionally, this final rule makes it clear that UNGSFs are not subject to any requirements of part 192, aside from § 192.12.

E. Suitability of API RPs 1170 and 1171 as the Basis for Rulemaking

In the IFR, PHMSA incorporated by reference two industry Recommended Practices, API RPs 1170 and 1171, into 49 CFR part 192.

1. Comments Concerning the Suitability of the RPs for Rulemaking

PHMSA used RPs 1170 and 1171 as the foundation for the new minimum safety standards for UNGSFs. Commenters cited the forewords of both RPs, which state that the RPs were not intended to substitute for Federal or State regulations as the basis for objecting to their use as the basis for new regulatory requirements. Other commenters identified potential gaps in regulatory coverage in the RPs, such as risk management practices for solution-mined salt caverns. For these reasons, commenters stated that the RPs were not an adequate basis for regulation.

Some commenters were concerned with the suitability of the RPs as the basis for regulations. Texas RRC and EDF criticized PHMSA's approach to incorporating the RPs into the underground natural gas storage regulations. The Texas RRC stated that the RPs were neither drafted nor intended to operate with the force and effect of Federal regulations and, as such, should not be adopted as written. Similarly, EDF pointed to the scope section of RP 1170, which states that the document is ''intended to supplement, but not replace, applicable local, State, and Federal regulations.'' Both the Texas RRC and EDF said they understood the engineering merit behind the RP, but expressed a belief that the RPs were more suitable as guidance material for operators.

Most private citizens urged PHMSA to go beyond the safety provisions in the RPs. Notably, these commenters expressed concern over the lack of a specific ''risk management'' section in RP 1170 for solution-mined salt caverns. They asked that the final rule provide additional risk management practices for solution-mined salt caverns.

A few commenters were concerned that the provisions in the RPs were vague, ambiguous, and insufficient in detail. For instance, States First said that while the RPs contain substantial information and guidance for operators, ''it is [States First's] belief that [the RPs] require considerable wording revisions and additions to make them effective as regulations.'' Similarly, MDEQ stated that the IFR lacked clear timeframes and provided little regulatory oversight and approvals for certain actions taken. MDEQ expressed concern that in many instances, the IFR left it up to operators to determine the risks facing their facilities and the methods for addressing them. It went on to say that IFR created inconsistencies and uncertainties in providing the level of protection needed. These inconsistencies and uncertainties in the IFR, in turn, could make it difficult for State regulators to address safety issues for intrastate gas storage operations by implementing additional regulations beyond the IFR.

2. Response to Comments Concerning the Suitability of the RPs for Rulemaking

PHMSA disagrees with the commenters' broad assertion that the API Recommended Practices are an inadequate basis for regulations. PHMSA routinely participates in consensus-standards-setting organizations that address pipeline design, construction, maintenance, inspection, and repair. These standards represent the best practices of the industry and, therefore, should be considered in the development of potential regulation. Agency participation in the development of these voluntary consensus standards is vital to eliminate the necessity for development or maintenance of separate, government-unique standards.

Further, the PIPES Act specifically directs the Secretary to consider ''consensus standards for the operation, environmental protection, and integrity management of underground natural gas storage facilities'' and ''the recommendations of the Aliso Canyon natural gas leak task force established under section 31 of the PIPES Act of 2016'' (49 U.S.C. 60141(b)). As

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discussed above, the Interagency Task Force issued a final report, titled ''Ensuring Safe and Reliable Underground Natural Gas Storage,'' making several recommendations. With respect to API RP 1170 and API RP 1171, the report recommended that ''[t]he incorporation of API RP 1170 and 1171 into the part 192 regulations will be an important step in improving the safety and reliability of underground gas storage facilities.'' [24] As a result, the report recommended that PHMSA consider incorporating the standards into part 192 in a manner that would make the standards enforceable.[25] After consideration of the RPs and the comments received concerning their incorporation, PHMSA concludes that the standards are sufficient to establish an initial, baseline level of regulation with the additions incorporated into this final rule. This initial regulatory framework will undoubtedly evolve and improve over time as PHMSA gains greater experience in this industry.

F. Integrity Management Practices

Integrity management is PHMSA's risk management program for identifying, assessing, and addressing potential threats that can have adverse consequences and a finite probability of occurring. The regulations in 49 CFR parts 192 (for gas pipelines) and 195 (for hazardous liquid pipelines) are a type of integrity management that PHMSA has applied to traditional pipeline systems. In place for over ten years, PHMSA's integrity management regulations had aided in the removal of thousands of defects from pipeline facilities before they failed and in the identification of preventive and mitigative measures to reduce the likelihood and consequences of failures potentially affecting high consequence areas. PHMSA expects that applying similar integrity and risk management practices to UNGSFs will have a similar effect on improving safety.

As discussed throughout this final rule, API RP 1170 and API RP 1171 outline the concepts of risk-based integrity management and provide instructions for the risk assessment and analysis process for UNGSFs. The IFR required operators of depleted hydrocarbon reservoirs and aquifer reservoirs to meet the risk-management requirements outlined in section 8 of RP 1171, which resembled PHMSA's existing IM program for gas and hazardous liquid pipelines. This section outlines the components of a process, including data collection, threat and hazard analysis, risk assessment methodology, preventative and mitigative measures, risk monitoring, and recordkeeping procedures.

The IFR did not contain a similar provision for operators of solution-mined salt cavern UNGSFs. The term ''Integrity Management'' is a systematic approach to analyzing and mitigating risk to promote the safe management and operations at a given facility. The IFR required operators of solution-mined salt caverns to meet the requirements of RP 1170, section 10, ''Cavern Integrity Monitoring,'' which directs operators to develop a holistic approach to maintaining well integrity but does not outline the components of an integrity-management process as explicitly as section 8 of RP 1171.

1. Comments Concerning Integrity Management Practices

As written, the risk-management practices in API RP 1170 (for solution-mined salt caverns) lack the specificity of the risk-management practices in section 8 of API RP 1171 (for depleted hydrocarbon reservoirs and aquifer reservoirs). Commenters identified the lack of robust risk management practices as a safety gap in the integrity program for solution-mined salt caverns and requested that the final rule supplement what is currently prescribed in API RP 1170.

Several commenters expressed concern that the RPs and, consequently, the IFR, lacked specific risk management criteria for solution-mined salt caverns. As Gas Free Seneca stated, RPs 1170 and 1171 mirror each other in every respect except for risk management. Gas Free Seneca, EDF, and some private citizens requested that the final rule add risk management standards for solution-mined salt caverns like the standards that exist for depleted hydrocarbon and aquifer reservoirs contained in section 8 of RP 1171.

EDF stated that the IFR called for depleted hydrocarbon and aquifer reservoir operators to develop risk management plans that address risks and provide plans to mitigate those risks. In its comments, EDF suggested that such a plan would be a good supplement to the regulations for solution-mined salt caverns. It stated that adding a risk management plan as a requirement in the final rule would be consistent with the natural gas storage rules being considered by California regulators following the incident at Aliso Canyon.

Gas Free Seneca, States First, EDF, and some private citizens requested that PHMSA mandate risk-acceptance criteria for underground natural gas storage facilities. Gas Free Seneca and private citizens asked that PHMSA set a measurable limit for risk and specify the types, frequency, and methods operators must use to collect and conduct risk analyses. States First asked that PHMSA set an acceptable level of risk so that operators would be required to meet an established standard, irrespective of their self-defined ''capabilities.'' EDF added that the final rule would benefit from the use of a risk-management ''heuristic'' such as ''ALARP,'' an acronym that stands for ''As Low as Reasonably Practicable.'' According to EDF, ALARP provides a process by which the regulated industry and the regulator can work together ''to systematically set appropriate levels of risk reduction.'' [26]

2. Response to Comments Concerning Integrity Management Practices

Based on the commenters' suggestions, and supported by an Interagency Task Force recommendation, PHMSA is making several enhancements to the integrity management provisions of the final rule. First, PHMSA is extending the risk management provisions of section 8, to salt-cavern UNGSFs, to the extent they apply to the physical characteristics and operations of solution-mined salt caverns, within one year of the effective date of the final rule. In other words, the final rule requires that UNGSFs using solution-mined salt caverns generally conform to the risk management practices that apply to UNGSFs using depleted hydrocarbon and aquifer reservoirs.

There are several reasons for this change. As discussed earlier, risk management is a standard concept in the oil and gas industry, although different programs may use slightly different terminology. Additionally, the Interagency Task Force recommended that PHMSA incorporate risk management practices into its regulations. During its initial site assessments, PHMSA observed that operators of solution-mined salt caverns were already in the process of conforming to risk management practices like those detailed in section 8. RP 1170 does address certain aspects of risk management practices but is less

[24] ''Ensuring Safe and Reliable Underground Natural Gas Storage,'' Final Report of the Interagency Task force on Natural Gas Storage Safety; October 2016. See pg. 63–64 of the final report at *https://www.energy.gov/downloads/report-ensuring-safe-and-reliable-underground-natural-gas-storage*.

[25] Ibid.

[26] ALARP is a principle more common in European law that sets an acceptable level of risk *as low as reasonably practicable.*

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comprehensive than RP 1171. For instance, section 10.2 of RP 1170 requires operators to ''take a holistic and comprehensive approach to monitor cavern integrity,'' which would include the identification and assessment of risks. Section 10.2 of RP 1170 goes on to say there is no single best method to achieve thorough cavern-integrity monitoring, thus leaving it up to an operator to evaluate the risks of each specific facility.

While the scope of RP 1171 is specific to depleted-hydrocarbon and aquifer reservoirs, much of section 8 is general enough that operators can readily apply the practices across all types of UNGSFs. PHMSA believes requiring the risk-management practices outlined in section 8 to all UNGSFs is the most practical method of directing all operators to manage the risks of gas storage releases on a case-by-case, facility-specific basis. This approach gives operators the flexibility to determine what actions are appropriate.

Second, § 192.12(d) uses slightly different terminology than what was used in the IFR to describe the risk management provisions that operators must follow. Whereas subsection 8.1 is titled ''Risk Management for Gas Storage Operations,'' § 192.12(d) is titled ''Integrity management program.'' This change is intended to confirm that the risk management program under the final rule has been broadened beyond what is provided solely under the RPs and that it is a variation of the IM programs established under parts 192 and 195 for gas transmission pipelines, interstate liquid pipelines, and gas distribution systems. The industry generally uses the term IM to describe the risk-management provisions of section 8, so it should be less confusing and more consistent to use the term IM to refer to all four integrity-management programs applicable to PHMSA-regulated pipeline facilities,[27] even though the details of each program vary slightly.

Third, as noted in the FAQs, this initial IM framework for depleted hydrocarbon and depleted aquifer reservoir UNGSFs that were constructed prior to July 18, 2017, and were subject to section 8 under the IFR, had to be in place by January 18, 2018. These operators must now implement a full IM program that includes the new provisions in the final rule within one year from the final rule's effective date.

Fourth, this final rule requires a slightly different process for UNGSF operators to develop a robust IM program, depending upon whether the facility is a depleted hydrocarbon or a depleted aquifer reservoir or whether it is a solution-mined salt cavern. For the former, the first step is to put together an initial ''framework'' based on the provisions of section 8, including:

- A general discussion or definition of risk management;
- Data collection and integration;
- Threat and hazard identification and analysis;
- Risk assessment;
- Preventive and mitigative measures;
- Periodic review and reassessment; and
- Recordkeeping.

For existing solution-mined salt cavern UNGSFs, they must implement a full IM program within one year from the effective date of the final rule. For new facilities constructed after the effective date of the final rule, they must have a full IM program in place before they commence operations. In addition, the final rule allows solution-mined salt cavern UNGSFs greater flexibility in meeting the provisions of section 8 by requiring that they meet only those provisions of section 8 that are applicable to the physical characteristics and operations of a solution-mined salt cavern. The two timelines differ because operators of solution-mined salt cavern facilities did not receive notice of having to meet the IM provisions of section 8 ''that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF.'' PHMSA believes that such a limitation on the IM program for solution-mined salt caverns is reasonable and readily ascertainable by operators of such facilities.

Fifth, in addition to the general framework outlined in section 8, the final rule includes several specific IM requirements for all UNGSF operators. Each operator's plan must include the following:

- A plan for developing and implementing each program element to meet the requirements of the final rule;
- The roles and responsibilities of UNGSF staff tasked with developing and implementing the IM program;
- An outline of the IM procedures to be developed;
- A plan for how staff will be trained in awareness and application of the operator's IM program;
- Timelines for implementing each IM program element, including the risk analysis and baseline risk assessments; and
- A plan for how to incorporate information gained from experience into the IM program on a continuous basis.

Because these are new, more specific requirements than those contained in the IFR, operators of existing UNGSFs will have an additional year to comply.

Sixth, PHMSA establishes a schedule for conducting the initial or ''baseline'' assessments for each reservoir or cavern and all wells. PHMSA has based this schedule on commenters' recommendations to use a ''phase-in'' timeline, similar to the UNGSF FAQs published in April 2017. The final rule requires that operators complete all baseline assessments for reservoirs and salt caverns and 40 percent of the baseline assessments for individual wells within four years from the effective date of this final rule. Operators must start with the higher-risk wells, as identified through the operator's risk-analysis process. The remaining 60 percent must be completed within seven years from the effective date of this final rule.

Seventh, the final rule requires that operators conduct periodic reassessments under API RP 1171, subsection 8.7, on a risk-based schedule. This final rule establishes that reassessment intervals must be no more than seven years. PHMSA assumed that the stress conditions for the downhole piping used at the well site are similar to the stress conditions for buried pipe. Because of this, PHMSA chose a seven-year reassessment (maximum) interval to be consistent with other gas pipeline regulations. However, an operator could determine its reassessment interval should be less than seven years based on its risk-based assessments.

Seventh, the final rule makes clear that operators may use one or more risk assessments completed before the effective date of the rule to establish a baseline assessment, so long as they meet the requirements of section 8 of RP 1171, and continue to be relevant and valid for the current operating conditions and environment. These requirements are consistent with the FAQs published in April 2017.[28] This requirement is intended to prevent operators from reproducing assessments that already meet the requirements of this final rule. The criteria and timing for reassessments should be determined using results from baseline assessments and updated risk analyses in accordance with section 8. Operators may also conduct new or additional assessments to supplement prior assessments as

[27] The integrity management provisions for gas transmission pipelines are found at §§ 192.901 through 192.951, for gas distribution pipelines at §§ 192.1001 through 192.1015, for hazardous liquid pipelines at § 195.452, and for UNGSFs at § 192.12, as amended by this final rule.

[28] *https://www.phmsa.dot.gov/pipeline/underground-natural-gas-storage/ungs-frequently-asked-questions.*

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necessary to establish a thorough understanding of a facility's risks.

Eighth, the final rule requires that operators maintain IM records in the same manner as pipeline operators are required to keep records under other IM provisions in parts 192 and 195. Maintaining IM records is critical if operators are to properly understand their systems, track and learn from experience, and to make continuous improvements. These records document how and why decisions are made to identify risks, set priorities among risks, conduct assessments, and identify and carry out preventive and mitigative measures. Further, operators must maintain IM records for the life of the UNGSF to demonstrate compliance with all the requirements under § 192.12(d). This level of documentation includes any calculation, amendment, modification, justification, deviation and determination made, and any action that is taken to implement and evaluate any element of an IM program. This level of documentation is the same standard found in § 192.947 for gas transmission systems and § 195.452(l) for hazardous liquid transmission systems.

Regarding the commenter's suggestion that PHMSA should apply a ''risk-tolerance'' model such as ALARP, PHMSA believes such a change is unnecessary. Integrity Management (IM) is one of many different varieties of risk management models used by different industries and organizations to handle safety risks to people and the environment. PHMSA's IM regulations require pipeline operators to identify the unique risks specific to their facilities comprehensively and to address those risks through a continuous program of gathering and analyzing data and learning from experience. PHMSA's approach places the onus on operators to identify, prioritize, and handle the risks posed by pipeline accidents. The IM requirements in this final rule are designed to be interpreted and applied essentially the same as the IM regulations currently applied to gas and hazardous liquid pipelines.

PHMSA believes that the integrity program outlined in § 192.12(d) and the RPs provides a flexible model that accounts for the diversity and variability of all UNGSFs, so long as the practices are risk-based and rigorously applied. To introduce a new model, such as ALARP, just for underground gas storage facilities and not other pipeline facilities, could be confusing for operators, PHMSA inspectors, and the public. Further, PHMSA is not aware of evidence that the ALARP model would provide an increase in safety.

G. Notification Criteria Under 49 CFR Part 191 for Changes at a Facility

The IFR added reporting requirements in 49 CFR part 191. PHMSA requires four types of reports from operators of UNGSFs: (1) Annual reports, (2) incident reports, (3) safety-related condition reports, and (4) National Registry information. PHMSA required this information because there was no that UNGSF operators follow the same provisions that gas pipeline operators must follow for providing PHMSA with notification of changes at their facilities.

Regarding the last type of report, PHMSA required National Registry information to identify the facility operator responsible for operators through an Operator Identification Number (OPID). The IFR required operators to notify PHMSA no later than 60 days before certain changes occur, including:

- Construction of a new UNGSF facility;
- Abandonment, drilling, or ''workover'' of an injection, withdrawal, monitoring or observation well. Concerning well workovers, the IFR stated that such work included the replacement of a wellhead, tubing or casing; and
- Changes in the entity (including company, municipality, etc.) that is responsible for an existing UNGSF and the acquisition or divestiture of an existing facility.

PHMSA clarified the IFR's notification requirements through April 2017 FAQs. For example, an operator should notify PHMSA of a ''replacement of a wellhead, tubing or casing.'' The FAQs said a ''replacement'' in this context meant the ''complete removal of the existing component and replacement with a new component (including replacement of wellhead, tubing, or casing).'' The FAQs further explained that there was no need for an operator to notify PHMSA of routine maintenance or repairs to existing components. The FAQs went on to say that operators should submit separate notifications for each storage field, but could bundle multiple activities within the same storage field in a single notification.

1. Comments on Notification Criteria Under 49 CFR Part 191 for Changes at a Facility

The IFR required UNGSF operators to notify PHMSA no later than 60 days before certain changes took place at their facilities took place, including changes in the operator of a facility and major new construction, as is currently required for other pipeline facilities. Operators found this reporting requirement excessive and recommended a monetary or activity threshold to reduce the volume of notifications. These commenters believed that the IFR's 60-day notification (reporting) requirement for new construction and construction-related activities was ambiguous and would result in excessive notifications. Some commenters expressed concern that the provision failed to exempt emergencies where advance reporting would be impractical.

LMOGA and TransCanada contended that PHMSA's notification requirement would duplicate their reporting burdens and cause delays because operators already had to notify states of construction activities and permitting. LMOGA expressed concern that a 60-day-notice to PHMSA for certain construction activities, such as well workovers, could shut down wells for an unnecessary amount of time. It stated that, currently, work permits for well workovers are issued by states in one to three days. TransCanada contended that PHMSA should remove the 60-day-notice requirement for new construction from the final rule altogether. It suggested that PHMSA could capture this same information through the annual report and safety-related condition reports instead of creating a separate notification requirement.

GPTC, PG&E, and others suggested other ways to streamline or reduce the notification burden involving new construction. For example, GPTC suggested that the final rule limit advance notifications to only those well workovers where a well was killed, a plug placed in the well for work, or a rig installed.

Another suggestion from PG&E was for PHMSA to adopt a monetary threshold for new-construction notifications, provide an exemption for emergency work, and define what activities would constitute a ''well workover.'' Regarding the monetary threshold, PG&E recommended that PHMSA only require operators to report well-workover and new-construction activities that cost more than $2 million. The company noted that PHMSA currently limits pipeline notifications [29] to those projects involving a certain minimum mileage or monetary threshold; it argued that applying similar thresholds for UNGSFs could reduce the reporting burden on operators.

[29] 49 CFR 191.22(c)(1)(i).

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2. Response to Comments on Notification Criteria Under 49 CFR Part 191 for Changes at a Facility

The purpose of the 60-day notification requirement in the IFR is to alert PHMSA of upcoming critical well work that requires an operator to control well pressure. One example of such a well-control activity is well abandonment. If an operator incorrectly performs an abandonment, then brine fluid or natural gas may migrate through the wellbore and escape into drinking-water aquifers or to the surface. If notified in advance, PHMSA will have the opportunity to review the operator's pre-work plan and observe the in-progress work. Ultimately, this process is beneficial for the operator and public safety because it ensures a comprehensive assessment of the operators' methods. Such notifications could prevent an incident or more costly remediation work. PHMSA will have the opportunity to review an operator's records of the project but, because most of the work is underground, reviewing the work in real-time is ideal.

PHMSA agrees with the commenters that it should narrow the scope of the notifications for changes to a facility that would eliminate excessive reporting of minor or routine maintenance. Accordingly, this final rule limits required notifications to PHMSA to only those involving new construction and major maintenance work. Specifically, the final rule provides that operators must notify PHMSA of (1) any new facility construction; (2) maintenance work that requires a workover rig and costs $200,000 or more for labor, materials, and services; and (3) any plugging or abandonment activities, regardless of cost.

The scope of this modified notification requirement is limited to only those types of activities that require adherence to specific methods and techniques to prevent damage to the formations and to safely control pressure in the well. Bringing in a workover rig marks a step-change in the degree of complexity and scope of work. The presence of a workover rig means the operator is opening the well, rather than just doing some wing valve work at the surface. Opening a well (requiring a workover rig) usually infers serious maintenance or repair work, performing extensive logging and integrity evaluations, or replacement of downhole components.

Concerning the $200,000 maintenance-work threshold, PHMSA has not indexed this exact dollar amount across all states and activity types. During preliminary inspections, PHMSA observed what high-risk activities were occurring in the field and generally how much it costs operators to complete those maintenance activities. PHMSA is aware that the costs of pressure-control and remediation activities vary considerably, depending upon the depth of the well, pressure, casing type and size, and other factors. However, PHMSA believes this is an appropriate threshold level that captures the higher-risk activities and still reduces the volume and burden of notifications. There is the possibility that a workover rig is needed for some minor issues, where the cost falls below the 200k threshold. Again, most major activities with a workover rig will cost more than $200,000, thus triggering this type of notification. Note that PHMSA also allows operators to report multiple well activities within the same storage field in a single notification.

PHMSA also recognizes that the IFR inadvertently omitted an exception for emergency maintenance or repairs. If an operator reasonably determines that it needs to do work immediately, for safety reasons, then it should not delay the work because of the 60-day notification requirement. Accordingly, the final rule adds a provision that allows operators to notify PHMSA as soon as practicable in instances where 60-day notice is not feasible due to an emergency. In such cases, an operator must promptly respond to the emergency, notify PHMSA as soon as practicable, and document the emergency and the reason for any delay in notification.

H. The States' Role in Regulating UNGSFs

There are approximately 403 active underground natural gas storage facilities (UNGSFs) in the United States, with about a 60/40 split between interstate and intrastate facilities. Interstate UNGSFs serve interstate facilities, and PHMSA has exclusive pipeline safety jurisdiction over the design, construction, operation, and maintenance of these facilities. Intrastate UNGSFs, on the other hand, are facilities that provide gas storage for intrastate pipelines, most notably local gas distribution companies (LDCs). Generally, these intrastate gas pipeline facilities have been subject to State regulation by its public utility commission or oil and gas commission. Intrastate UNGSFs continue to be subject to State regulation, but only if the applicable State authority has filed a certification with PHMSA to participate as a full State partner under the new Federal program and receive Federal funding through PHMSA.

The Federal regulatory program for UNGSFs has been set up to mirror the existing Federal-State pipeline regulatory partnership for gas and hazardous liquid pipelines as established by the Natural Gas Pipeline Safety Act in 1968 and the Hazardous Liquid Pipeline Safety Act of 1979, respectively. Under this system, Congress has conferred on the Department primary jurisdiction over all natural gas and hazardous liquid (primarily oil) pipelines in or affecting interstate commerce but has preserved the states' role in regulating intrastate pipelines, as long as the State that chooses to submit an annual certification to PHMSA and agrees to enforce the minimum Federal standards in addition to any State regulations compatible with the Federal standards.

The PIPES Act directed PHMSA to expand its pipeline-safety regulatory program to include the storage of natural gas incidental to transportation, using this same Federal-State model. Just as various states had previously regulated intrastate natural gas pipelines before the passage of the Natural Gas Pipeline Safety Act of 1968, so too have many states regulated UNGSFs prior to the passage of the PIPES Act and issuance of the IFR. These states will be able to continue this important safety role as partners with PHMSA.

Under the IFR and this final rule, intrastate UNGSF facilities will be regulated in one of two ways. Depending upon State law, they will be regulated either by a certified State entity (*e.g.,* public utility commission or oil and gas commission), or, in the absence of a certified State partner, by PHMSA. Notably, section 12 of the PIPES Act expressly allows a State authority to adopt additional or more stringent safety standards for intrastate UNGSFs, provided such standards are compatible with the minimum Federal requirements. PHMSA interprets this to mean that any State authority that has filed an annual State certification with PHMSA under 49 U.S.C. 60105 to regulate UNGSFs may regulate and enforce its own additional or more stringent regulations against intrastate UNGSFs that fall under that authority's State jurisdiction, to the extent that the additional State standards are compatible with the Federal safety regulations. This arrangement is the same as the States' authority to regulate all other intrastate pipeline facilities under parts 192 and 195.

Accordingly, States that had UNGSF regulations before the adoption of the IFR may continue to implement any

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additional or more stringent regulations that they currently enforce with respect to intrastate facilities, to the extent that such regulations are compatible with the minimum standards set by this final rule. For a State wanting to expand its authority to inspect interstate facilities under the final rule, it will be able to apply to PHMSA for discretionary interstate agent status under 49 U.S.C. 60106(b), just as a State authority today, may carry out such a role for other oil and gas pipeline facilities.

It is worth noting that neither the PIPES Act nor this final rule alters the existing role of the States in the siting or permitting of UNGSFs or their regulation of natural gas production. PHMSA has never exercised regulatory control over these issues for pipeline and will not be doing so under the final rule. Instead, the PIPES Act provides that all UNGSFs incidental to gas ''transportation'' are now subject to Federal minimum safety standards promulgated by PHMSA. Section 12 of the PIPES Act directs PHMSA to exercise this authority in conjunction with its State partners in the same manner as other pipeline facilities are regulated.

This means FERC and the States will continue to exercise their respective authorities over the permitting of UNGSFs. FERC reviews applications for the construction and operation of UNGSFs owned by interstate gas pipeline operators and that are integrated into their pipeline systems. In its application review, FERC requires an applicant to certify that it will comply with DOT safety standards. While FERC has no jurisdiction over pipeline safety, PHMSA and FERC actively collaborate to exercise their respective responsibilities.[30]

PHMSA received several comments regarding the effect of the IFR on the role of the states in UNGSF regulation. These comments dealt primarily with concerns expressed by State regulators and gas-storage operators over PHMSA's role and the nature of the Federal-State partnership under this new regulatory scheme. These commenters also asked PHMSA to explain the roles of the various parties in permitting UNGSFs, to discuss the potential conflicts that may arise between existing State regulations affecting underground storage and the new Federal minimum safety standards and the degree to which certain existing State regulations will continue to apply to interstate UNGSFs. Of particular concern was whether the IFR could serve to undermine or reduce the existing level of safety and environmental protection that several States have been applying to interstate UNGSFs, especially where certain State standards could arguably be viewed as broader or more stringent than the RPs being adopted in the final rule. These comments are discussed below in more detail.

1. Comments on State Permitting of UNGSFs

In its comments, the Texas RRC asked PHMSA to clarify the States' role in permitting UNGSFs and commented that the IFR provided no specific details regarding permitting areas that fall to the states.[31] The commission noted that while the IFR accurately stated that permitting of gas wells is not a PHMSA function, PHMSA had incorrectly concluded: ''that the traditional role of permitting intrastate facilities falls to the states and the permitting of interstate facilities falls to the Federal Energy Regulatory Commission (FERC).'' According to the Texas RRC, ''FERC is not set up to conduct permitting of individual wells, ensuring proper notification is provided to all entitled parties, reviewing and adequately protecting groundwater, and protecting correlative rights.'' Conversely, the Texas RRC explained that under Texas law, the Texas RRC is directed to regulate the downhole portion of UNGSFs to fulfill its mandate to conserve State natural resources and to protect the environment. Therefore, it argued, ''all of these functions must fall to the State regardless of whether a well is part of an intrastate or interstate facility.'' Finally, the Texas RRC argued that the failure of PHMSA to properly address these scenarios ''indicates a lack of a clear understanding of underground natural gas storage and the historical role many states have had in its successful regulation of underground hydrocarbon storage.''

Similarly, Dow Chemical asserted that many states had established successful regulations and standards for permitting, operations, maintenance, monitoring, and other issues related to UNGSFs. The company pointed out that states with underground-storage safety regulations typically regulate both intrastate and interstate facilities. Along with Dow Chemical, LMOGA, MDEQ, and the Texas RRC recommended that PHMSA consult with State regulatory agencies to avoid unnecessary reporting and compliance programs and to learn from the states' experience in regulating UNGSFs as it continues to develop Federal regulations.

2. Response to Comments on the State Permitting of UNGSFs

As for the comments seeking greater clarity on how the IFR affects State permitting of UNGSFs, PHMSA has not made any changes to the regulatory text because PHMSA does not have the authority to prescribe the location or siting of UNGSFs. This final rule also does not deal with permitting, directly. Section 12 of the PIPES Act expressly states that the Act shall not be construed to authorize PHMSA ''to prescribe the location of an underground natural gas storage facility'' or ''to require the Secretary's permission to construct'' a UNGSF.

3. Comments on State Regulation of UNGSFs Associated With Gas Production

IPAA, EDF, and Hilcorp requested that PHMSA clarify how the IFR applied to UNGSFs associated with gas-production facilities. IPAA stated that the Pipeline Safety Laws do not provide PHMSA with authority to regulate gas-production facilities, citing 49 U.S.C. 60101(a)(21)(A) and 60101(a)(22)(B). IPAA, EDF, and Hilcorp requested that PHMSA add an exception to part 192, specifically excluding UNGSFs that are ''in direct support of'' (Hilcorp) or that are ''co-located with and used to support of'' (IPAA) production operations.

IPAA gave two examples of the types of production-related UNGSFs located in active production fields that are used to manage production operations, rather than providing ''commercial storage services.'' The first type was facilities that store gas from a production field but has not yet entered a PHMSA-regulated pipeline. The second type was UNGSFs that are used for gas production purposes ''after being delivered to the production field in a PHMSA-regulated pipeline.'' In other words, they store gas that has either not yet entered transportation or that has ended transportation. Under both scenarios, IPAA contended, the stored gas at these facilities is not incidental to transportation but is used to support gas production. According to these industry commenters, such UNGSFs are used in the process of extracting natural gas from the ground and should not be treated as providing storage incidental to transportation under the Pipeline Safety Laws.

[30] Page 28. *https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[31] *See State of Texas* v. *PHMSA,* No. 17–60189 (5th Cir. Mar. 17, 2017).

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4. Response to Comments on UNGSFs Associated With Gas Production

The PIPES Act directed PHMSA to establish minimum Federal standards for all UNGSFs that store natural gas incidental to transportation. Again, the PIPES Act does not alter or expand PHMSA's jurisdiction as it has traditionally been applied to natural gas production or hazardous liquid production facilities. While PHMSA has never exerted jurisdiction over gas pipeline facilities that are engaged exclusively in production and has long recognized the authority of states to regulate the permitting and siting of pipelines and to protect groundwater and other State natural resources. Only after transportation has begun and before delivery to an end-user is there any issue of PHMSA jurisdiction, which is limited to the transportation of gas and hazardous liquids.

This is analogous to PHMSA's regulation of other types of temporary storage of hazardous liquid in transit. For example, petroleum being transported by pipeline is often stored temporarily along the line in one or more breakout tanks. These tanks are used to relieve surges or receive and store hazardous liquid transported by pipeline for eventual re-injection and continued transportation by pipeline (49 CFR 195.2). Similarly, under this final rule, a UNGSF is defined as a gas pipeline facility "that stores natural gas underground and incidental to the transportation of natural gas" in interstate or foreign commerce.

PHMSA interprets this to mean that if a UNGSF is used in any way to store gas that is received from a PHMSA-regulated pipeline and returns any of that stored gas to transportation by pipeline, then such a facility is incidental to transportation and therefore covered by this final rule. Even if some of that gas is used to support production operations or is mingled with produced gas that has not yet entered transportation, the storage facility itself will be treated as a UNGSF under the final rule and will be subject to PHMSA's full jurisdiction.

5. Comments on States' Regulation of Intrastate UNGSFs

Several commenters expressed concern that the IFR potentially conflicted with existing State regulation of intrastate UNGSFs and that the IFR lacked clarity on how such conflicts could be avoided or minimized. MDEQ, for instance, commented that its Oil, Gas and Minerals Division ran a regulatory program affecting many safety and environmental issues covered by the RPs and that "Michigan's existing regulations are needed to fill gaps in the IFR particularly in the areas of permitting, liquid waste handling and disposal; and environmental protection from liquid hydrocarbons, brines, and other liquid contaminants." The agency further commented that the IFR "makes no mention of pollution prevention, nor does it set standards for remediation of spills." It noted that many UNGSFs are located in oil reservoirs that still produce liquid hydrocarbons and brine, and that the State of Michigan has comprehensive regulations covering pollution prevention, groundwater monitoring, remediation, and clean-up activities. In short, the State urged PHMSA to "recognize the states' role in these areas."

6. Response to Comments on the States' Regulation of Intrastate UNGSFs

First, PHMSA recognizes and supports the role that many states have played for many years in the field of underground gas storage. Nothing in the IFR or this final rule is intended to minimize or diminish the states' role in ensuring the safety of UNGSFs, protecting the environment, or safeguarding critical State resources. Section 12 of the PIPES Act, however, mandates that PHMSA regulate all UNGSFs that storing natural gas incidental to transportation. Under 49 U.S.C. 60104(c) and the recently-enacted 49 U.S.C. 60141(e), states with existing regulations may continue to regulate intrastate gas storage facilities to the extent that the proper State authority becomes certified by PHMSA and the State regulations are compatible with the new Federal minimum safety standards.

Second, the PIPES Act and this final rule do not modify or undermine established principles of Federal preemption law as applied to pipeline safety. Any State regulation affecting PHMSA's exclusive jurisdiction over the safety of interstate pipeline transportation facilities is, and always has been, preempted by the Pipeline Safety Laws.[32] The enforceability of existing or new State regulations affecting gas production, storage, plugging, or other areas such as mineral rights, depends on whether the State regulations are based on an independent basis under State law and cannot be considered safety regulations preempted by the PIPES Act, which is necessarily a case-by-case determination.

Third, the PIPES Act and this rule represent a major step forward in extending minimum Federal safety standards to all interstate gas storage facilities, regardless of whether individual states have already adopted regulations governing storage facilities or whether individual interstate operators have voluntarily complied with existing State regulations. As PHMSA discussed in the IFR, interstate UNGSF facilities would not be subject to any regulatory safety requirements in the absence of this Federal action.

Fourth, PHMSA fully recognizes that states with UNGSFs typically have various regulations in place governing the construction, remediation, and plugging of gas wells. Before the IFR went into effect, many interstate UNGSF operators relied on these State regulations to help develop best practices. State safety jurisdiction, however, extends only to intrastate UNGSFs. Regulations differ from State to State, making it difficult for operators to maintain consistent performance across all their interstate facilities. Finally, PHMSA will incorporate lessons learned from operators and states implementing this final rule in the form of guidance and additional rulemakings. PHMSA understands that seeking input from states is a vital component in developing an effective underground natural gas storage program at the Federal level.

As for the comments regarding potential conflicts between existing State regulation of intrastate UNGSFs, three points should be made. First, many State agencies enjoy independent authority under their own particular State's laws to regulate UNGSF involving public health, protection of groundwater, allocation of mineral rights, and similar areas not involving safety. Under established Federal preemption law, States may regulate in such areas that are not preempted expressly by Federal law or regulation.

In the field of underground natural gas storage, Congress, through the PIPES Act, has conferred authority on the Secretary (and delegated to PHMSA) to provide for the safety of natural gas storage facilities incidental to transportation, just as it has for other oil and gas pipeline facilities. This authority covers the design, construction, operation, and maintenance of UNGSF facilities. States are precluded from regulating the safety of UNGSFs to the extent that such State regulations conflict with PHMSA's safety-related regulations. To determine whether specific State regulations are preempted by the PIPES Act and this final rule may require a fact-specific analysis of whether a particular State regulation has been preempted, an

[32] *See, e.g., Colorado Interstate Gas Company* v. *Wright,* 707 F. Supp. 2d 1169 (D. Kan. 2010).

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analysis that falls within the purview of State and Federal courts. Such preemption determinations have routinely been made by the courts to resolve challenges to State and local governments' authority to regulate gas and hazardous liquid pipelines.

Second, any potential conflict between existing State regulations governing intrastate UNGSFs and Federal safety regulations disappears, in most cases, in those states that have submitted annual certifications to PHMSA and become UNGSF State partners. All State partners in this program will have the authority to adopt and enforce additional or more stringent safety regulations than the minimum Federal standards set forth in the IFR. PHMSA anticipates and hopes that many states, such as Texas, Michigan, and other commenters that already have existing regulations affecting intrastate UNGSF safety, will decide to partner with PHMSA and enjoy the enhanced authority, Federal funding, and other benefits that accompany State certification.

Third, PHMSA encourages and supports State regulatory programs that help ensure all UNGSFs, both intrastate and interstate, address resource conservation, environmental protection, land use, emergency response, and other important issues affecting gas wells and storage outside the realm of safety.

PHMSA agrees with MDEQ's comments and encourages MDEQ to examine its existing State UNGSF regulations to determine whether any of them are safety-related standards that could be preempted by this final rule in the event Michigan decides that it does not wish to become a certified State partner for intrastate UNGSFs. If Michigan does become a State partner for UNGSFs, then MDEQ (or other State authority in Michigan) will be able to apply additional or more stringent safety standards, provided they are "compatible" with the minimum Federal standards prescribed under the Pipeline Safety Laws and this final rule. If it chooses not to become a State partner for UNGSFs, then the Federal minimum safety standards will apply to all intrastate UNGSFs in Michigan, and PHMSA will inspect such facilities and enforce the Federal minimum standards against all intrastate UNGSFs in the State.

7. Comments on States' Regulation of Interstate UNGSFs

Some commenters, including EDF and the Interstate Oil and Gas Compact Commission, expressed concern that the IFR did not go far enough in exercising jurisdiction over UNGSFs in a manner that optimized existing State regulations. EDF commented that the new Federal regulations would create a "ceiling" on State regulations for the permitting, drilling, completion, and operation of underground storage wells that have also been applied to interstate facilities. EDF acknowledged that while interstate facilities are under the exclusive safety jurisdiction of PHMSA, intrastate UNGSFs are frequently subject to both safety regulations promulgated by PHMSA and to other gas-storage rules promulgated by State regulators that generally apply to all gas wells in their particular states. EDF expressed the fear that interstate UNGSF operators who had been "voluntarily obeying State rules responding to the State's unique geology, level of subsurface activity, competing surface activities and general appetite for risk may, with the cover of PHMSA's IFR, decline to continue following those rules, possibly to the detriment of safety and the environment."

To address this concern, EDF asked PHMSA to include two specific provisions in the final rule. First, it asked PHMSA to distinguish between those State regulations of general applicability to all oil and gas wells (*i.e.,* those falling within the jurisdiction ceded to states under the Natural Gas Act of 1938) and those addressing the special risks intrinsic to gas storage wells. EDF requested that PHMSA direct interstate operators to adhere to State regulations for permitting, drilling, completion and operation of storage wells, but "only to the extent the regulations address risks of general applicability to all oil and gas wells and where it is not impossible to comply with both the State regulations and PHMSA requirements."

Second, EDF asked PHMSA to require interstate operators in states having adopted "storage" regulations to identify all State rules that an operator believes are "storage" rules and address those rules in their risk management plans as part of the operators' preventive and mitigative measures to address "special risks intrinsic to gas storage." According to EDF, this would serve to preserve the efforts made by some states to ensure safety and environmental protections imposed in the face of no minimum Federal standards.

8. Response to Comments on the States' Regulation of Interstate UNGSFs

As noted earlier, EDF and other commenters have pointed out that a number of interstate UNGSF operators in states with mature regulatory programs in place have been "voluntarily" obeying State rules. PHMSA acknowledges EDF's concern that some interstate operators may choose to no longer voluntarily comply with State UNGSF regulations that go beyond the new minimum Federal standards embodied in the final rule. However, the Federal standards do not disincentivize the voluntary compliance that was previously occurring before the IFR went into effect, provided that the voluntary compliance is compatible with the Federal standards. Therefore, it seems unlikely that an interstate operator who is already voluntarily complying with existing State safety-related standards would stop doing so because of this final rule unless voluntary compliance were to result in non-compliance with the Federal standard. Further, this is the same situation that exists with other State regulations that may affect gas and hazardous liquid pipelines and with which interstate operators may or may not choose to comply. For these reasons, PHMSA declines to modify the final rule to require interstate operators to take such State regulations into account in their IM plans or other procedures. The agency believes it would be inconsistent and impracticable to require operators to evaluate and include in their plans and procedures certain provisions of State regulations for UNGSFs but not for other pipeline facilities. This would put PHMSA in the untenable position of elevating certain State regulations for all interstate UNGSF operators but not for other State pipeline regulations. If PHMSA learns of State regulations that should be applied more broadly for all interstate UNGSF operators, it may consider amending its regulations through notice-and-comment rulemaking to make them applicable uniformly among all interstate operators.

I. Definitions and Terminology

The IFR added a definition for "underground natural gas storage facility" at 49 CFR 191.3 based on the definition provided in section 12 of the PIPES Act. The IFR's definition included the wellhead, downhole components, and associated onsite structures that lay within the scope of PHMSA's regulatory authority. The IFR provided no additional definitions.

1. Comments Regarding Definitions and Terminology

Several commenters asked that PHMSA modify the definition of "underground natural gas storage facility" in the final rule and to clarify or define other terms not defined in the IFR. Two commenters requested that

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PHMSA create separate definitions for interstate and intrastate facilities. They said that clarification in the final rule would prevent jurisdictional confusion at the State level and enable their organizations to apply the rules more predictably.

Operators recommended a revised definition of ''underground natural gas storage facility,'' while others asked that PHMSA clarify the terms ''workover'' and ''modified well.''

The Associations recommended that PHMSA revise the definition of ''underground natural gas storage facility'' to avoid confusion with other subparts of 49 CFR part 192. They were concerned that the definition in the IFR included ''piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment,'' terminology that could imply components of a UNGSF were covered by both the underground natural gas storage regulations at § 192.12 and other provisions in part 192. They recommended that the definition of ''underground natural gas storage facility'' be amended to exclude ''facilities covered by part 192 of this chapter.''

The Associations further noted that the definition of a UNGSF included the term ''solution-mined salt cavern reservoir.'' They stated that the term ''reservoir'' is inaccurate in reference to salt caverns and recommended that PHMSA use the term ''a solution-mined salt cavern'' for technical accuracy. Similarly, the GPTC recommended that the final rule revise the definition of UNGSF to align with the scope of the RPs 1170 and 1171.

Similarly, PG&E recommended that PHMSA replace the definition of ''underground natural gas storage facility'' at § 192.3 with the following:

> ''Underground gas storage facility means a facility that stores natural gas in an underground facility incidental to natural gas transportation, which is constructed from a depleted hydrocarbon reservoir, an aquifer reservoir, or a solution-mined salt cavern. In addition to the reservoir, this also includes the injection, withdrawal, monitoring, observation wells, and associated wellhead equipment within the facility.''

PG&E also recommended that PHSMA remove the phrase ''including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility'' from the criteria for submitting a safety-related condition report under § 191.23. The company stated that because such equipment was already included in the definition of ''underground natural storage facility,'' operators might incorrectly conclude that two reports were required since the equipment was already covered under other provisions of part 191.

Northern Natural Gas, stated that the definition of a ''modified well'' was not clear and could be interpreted to include some minor or routine operations, such as the replacement of downhole equipment, casing repairs, or tubing changes.

2. PHMSA's Response to Comments Regarding Definitions and Terminology

PHMSA agrees with the commenters' suggestion to revise the definition of ''underground natural gas storage facility,'' and, therefore, is amending it in this final rule. The revised definition will better articulate the point of demarcation between facilities that constitute the UNGSFs and those that are part of other gas pipeline facilities. Traditionally, compressor units, buildings, and separators have been considered part of the ''topside'' pipe domain and are already regulated by other sections of part 192. These components can be connected to or from UNGSFs. PHMSA considers a UNGSF to include all components up to the valve assembly (and their flanges) that route gas at the wellhead to or from the connected pipeline(s). The valve assembly may be a single manual or automated valve or a combination of valves (*e.g.,* manual and emergency shutdown) and will be located near the wellhead.

With respect to the need for separate definitions for intrastate and interstate UNGSFs, PHMSA sees no need for such definitions. The use of the phrase ''incidental to natural gas transportation'' in 49 CFR 192.3 makes clear that the scope of PHMSA's jurisdiction over UNGSFs does not depend upon whether a facility is ''interstate'' or ''intrastate'' but whether it is tied to ''transporting gas,'' as that term is defined under 49 U.S.C. 60101(a)(21). This means that UNGSFs may include gas storage facilities that can be used occasionally or partially for production operations, such as enhanced recovery, gas lift, and for production equipment such as power generation and powering compressors and pumps.

Other commenters requested that PHMSA clarify common terms used throughout RPs 1170 and 1171, such as ''wellhead,'' ''workover,'' or ''modified well.'' For similar reasons, the final rule does not provide definitions for technical terms generally known to industry, such as ''wellhead,'' ''modified well,'' and ''workover.'' PHMSA will work with operators on a case-by-case basis should the need arise to determine the appropriate application of such terminology under the modified regulatory text in the final rule.

J. Requests for Additional or More Stringent Requirements

PHMSA received several comments from private citizens related to additional or more stringent requirements for UNGSFs that do not fit into the other categories already discussed. Gas Free Seneca, EDF, and several private citizens asked PHMSA to require the widespread use of subsurface safety valves. Some called for a plan to decommission UNGSFs. Others called for a moratorium on new facilities.

The widespread use of subsurface safety valves may have value but would require further study and research as to their effective use at each type of UNGSF over other safety enhancements or alternatives. In PHMSA's ongoing discussions with operators, the failure rates of subsurface safety valves during testing are variable. Additionally, once installed, an operator would have to re-open the well to make any repairs to the subsurface safety valve, requiring a workover rig to retrieve the valve. Given these factors, PHMSA would require additional certainty and a strong safety case before promulgating a Federal requirement for the widespread use of subsurface safety valves.

As for a moratorium, PHMSA does not have the authority to site UNGSF facilities (and, by extension, to ban new facilities) or to abrogate the power of states to issue permits. Therefore, a moratorium would be outside the scope of PHMSA's authority and contrary to the PIPES Act.

PHMSA recognizes that there are inherent risks to operating a UNGSF; however, Federal and State regulations minimize these risks by requiring operators to adhere to clear performance standards designed to maintain the integrity of the wellhead and reservoir or cavern. Furthermore, the addition of requirements in this final rule related to IM and recordkeeping will add greater rigor to the risk-management practices than in the IFR. In summary, the IFR and this final rule constitute the first large-scale application of PHMSA's regulation jurisdiction to UNGSFs. As operators begin applying the RPs and assessing the integrity of their facilities and as PHMSA gains experience in regulating UNGSFs, the need for any additional prescriptive measures will become apparent.

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IV. Rulemaking Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*), as amended by the PIPES Act (Pub. L. 114–183, June 22, 2016). Section 60102 authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The Secretary has delegated her authority in this area to the Administrator of PHMSA (49 CFR 1.97). PHMSA is issuing the amendments to the requirements for UNGSF involved in pipeline transportation under this authority.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

This final rule is a significant action under section 3(f) of E.O. 12866. Therefore, the Office of Management and Budget (OMB) has reviewed it.

PHMSA prepared a regulatory impact analysis (RIA) for the final rule, which details the potential for incremental benefits and costs. The RIA, which is available in the docket for this final rule, Docket No. PHMSA–2016–0016, provides an estimate of the annualized cost savings of the final rule and the other alternatives considered relative to the baseline. Given the final rule does not impose any costs relative to the baseline (IFR), PHMSA determined that the final rule is not economically significant under Executive Order 12866 because the estimated annual impact is less than $100 million.

Under the final rule, PHMSA expects operators to continue performing the same preventative safety measures that they are performing under the IFR. Because PHMSA does not expect the final rule to change operator safety-related actions, PHMSA does not expect changes to the benefits relative to the IFR. Implementation of the IFR already achieved benefits that will remain in place, including the potential prevention of catastrophic natural gas releases due to the failure of storage wells and the associated impacts on human health, property, and the environment, including climate change.

PHMSA does anticipate cost savings once the final rule becomes effective. Using the IFR as a baseline, the final rule will reduce recordkeeping and reporting burdens, and burdens associated with technical evaluations of non-mandatory RPs. The estimated annualized cost savings as a result of these changes is $8,452,365 to $12,810,620 when discounted to present value at 7 percent.

C. Executive Order 13771

This final rule is considered an E.O. 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in the rule's economic analysis.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, requires Federal agencies to consider the impact of their rules on small entities, analyze alternatives that minimize those impacts, and make their analyses available for public comments. The Act is concerned with three types of small entities: Small businesses, small nonprofits, and small government jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures that Federal agencies must complete unless they certify that the rule, if promulgated, would not have a significant economic impact on a substantial number of small entities. A statement of factual basis must support this certification, *e.g.,* by addressing the number of small entities affected by the proposed action, calculating expected cost impacts on these entities, and evaluating economic impacts.

PHMSA estimated that this final rule would affect 130 operators. Of these 130 operators, there are 14 small entities. However, this final rule is a deregulatory action that will reduce the burden of information collections. Therefore, PHMSA has determined that this final rule will not have a significant economic impact on any small entities.

E. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, requires that Federal agencies assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under Section 202 of UMRA, PHMSA must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year (*i.e.,* $153 million in 2016 dollars). This final rule will not result in such expenditure. Accordingly, PHMSA is not required to provide a written statement in accordance with the UMRA.

F. National Environmental Policy Act

PHMSA has analyzed this final rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR 1500–1508), and DOT Order 5610.1C. PHMSA has published the results of this analysis in an Environmental Assessment (EA) as required by 40 CFR part 1502.

Based on the EA, PHMSA has determined this final rule would not significantly affect the quality of the human environment. To assess the impact of these regulations on the human environment, PHMSA considered three alternative scenarios, including adopting the IFR without amendments, the API RPs as written, and the provisions in this final rule. PHMSA concludes that this action will not significantly affect the quality of the human environment.

To the extent that the measures taken to comply with the IFR did not involve additional environmental impacts and instead served to reduce the risk of natural gas incidents, PHMSA expects this final rule to continue these positive environmental impacts. The information in this Environmental Assessment report supports a Finding of No Significant Impact (FONSI) for this final rule.

G. Executive Order 13132

E.O. 13132 (''Federalism'') (64 FR 43255, Aug. 10, 1999) requires PHMSA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' E.O. 13132 defines policies that have federalism implications to include regulations that have ''substantial direct effects on the states, on the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government.''

Section 6 of E.O. 13132 limits regulations that impose substantial direct compliance costs on a State unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments. PHMSA also may not issue regulations that preempt State law unless the agency consults with State and local officials early in the process of developing the regulation.

PHMSA has concluded that this action will not have federalism

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implications because it does not impose any direct compliance costs on State or local governments. This final rule reduces the burden from information collection and therefore does not impose any direct compliance costs.

With respect to preemption, E.O. 13132 requires agencies to determine if their regulatory actions would preempt State law or impose a substantial direct cost in compliance on them. Congress explicitly addressed the preemption of State underground storage regulations in the PIPES Act in section 60141(e). A State authority may adopt additional or more stringent safety standards for intrastate underground natural gas storage facilities as long as they are compatible with Federal requirements. This statement is consistent with the existing statute governing PHMSA's preemption of State regulation over intrastate pipeline transportation facilities at 49 U.S.C. 60104(c).

As noted in the IFR and the discussion above, interstate facilities would not be subject to any regulatory safety requirements with respect to their wellhead and downhole facilities in the absence of Federal action. Even before the issuance of the IFR, the Federal Pipeline Safety Laws preempted any State regulation purporting to affect interstate pipeline transportation facilities. States with existing underground natural gas storage regulations may continue to implement those additional, and possibly more stringent, regulations on intrastate gas storage facilities to the extent that the State regulations are compatible with the new Federal regulations outlined in this final rule. Interstate underground storage facilities are now subject to the new Federal regulations, whereas previously, those facilities were not subject to any regulatory safety requirements.

H. Executive Order 13175

E.O. 13175 (''Consultation and Coordination with Indian Tribal Governments'') reaffirms the Federal Government's commitment to the Tribal sovereignty, self-determination, and self-government. To that end, the agencies must consult with Tribal governments as they develop policy on issues that may affect those communities. This final rule imposes no substantial direct compliance costs or burdens on Tribal governments. So, the requirements of E.O. 13175 do not apply.

I. Executive Order 13211

E.O. 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') requires Agencies to prepare a Statement of Energy Effects when undertaking certain actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (i) Any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use.

In a memorandum on E.O. 13211, OMB outlines the criteria for assessing whether a regulation constitutes a ''significant energy action'' and would have a ''significant adverse effect on the supply, distribution or use of energy.'' [33] Of the potentially adverse effects on the supply, distribution, relevant to this final rule, only one of the criteria is applicable to this final rule: The ability of interstate operators to pass costs on to consumers. However, because this final rule results in cost savings, it would not increase the cost of energy distribution.

J. National Technology Transfer and Advancement Act of 1995

The National Technology Transfer and Advancement Act of 1995, 15 U.S.C. 272, directs Federal agencies to use voluntary consensus standards instead of government-written standards when appropriate. The OMB Circular A–119, ''Federal Participation in the Development and Use of Voluntary Consensus Standards and in Conformity Assessment Activities,'' sets the policy for Federal use and development of voluntary consensus standards. As defined in OMB Circular A–119, voluntary consensus standards are technical standards developed or adopted by domestic and international organizations. These organizations use agreed-upon procedures to update and revise their published standards every three to five years to reflect modern technology and best technical practices.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which standards it should add, update, revise, or remove from 49 CFR subchapter D. PHMSA handles these changes to incorporate by reference materials via the rulemaking process, which allows the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

PHMSA worked to make the materials incorporated by reference reasonably available to interested parties. PHMSA is prohibited from issuing a regulation that incorporates by reference any document unless that document is available to the public, free of charge (Pub. L. 113–30, Aug. 9, 2013).

To meet these requirements, PHMSA negotiated agreements with all but one of the respective standards developing organizations (SDO) with standards already incorporated by reference in the PSRs to make viewable copies of those standards available to the public at no cost. PHMSA has an agreement in place with API, who voluntarily made the RP 1171 and RP 1170 available on API's public website. API's mailing address and the website are listed in 49 CFR part 192.

K. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 [34] (PRA), Public Law 104–13, is implemented by OMB and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of ''information collection'' includes activities required by regulations, such as for permit development, monitoring, recordkeeping, and reporting. The term ''burden'' refers to the ''time, effort, or financial resources'' the public expends to provide information to or for a Federal agency or to fulfill statutory or regulatory requirements otherwise. The PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests.[35] Information collection activities may include:

- Reviewing instructions;
- Using technology to collect, process, and disclose information;
- Adjusting existing practices to comply with requirements;
- Searching data sources;
- Completing and reviewing the response; and
- Transmitting or disclosing information.

[33] E.O. 13211 was issued May 18, 2002. The Office of Management and Budget later released an Implementation Guidance memorandum on July 13, 2002.

[34] Substantially amending the PRA of 1980 (Pub. L. 96–511).

[35] 44 U.S.C. 3502(2); 5 CFR 1320.3(b).

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Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly affects a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number. OMB has previously approved the information collection requirements contained in IFR under the provisions of the PRA. Since issuing the IFR, PHMSA has estimated changes in reporting and recordkeeping burden and submitted a revised information collection request to OMB for approval. Below is a summary the information collections requested or approved for this final rule.

1. Incident Reporting

PHMSA is finalizing the IFR's revision to 49 CFR 191.15 that requires operators to give notice upon the discovery of incidents meeting the definition at 49 CFR 191.3. Operators must submit DOT Form PHMSA–F7100.2 as soon as practicable but not more than 30 days after they detect the event. On August 16, 2017, OMB approved the use of this form, ''Incident and Annual Reports for Gas Pipeline Operators,'' under Control No. 2137–0522.

2. Safety-Related Conditions Reporting

PHMSA is finalizing the IFR's revision to § 191.23 that requires operators to report a safety-related condition no later than ten working days after its discovery. PHMSA estimates it will receive four annual responses at an annual burden of 24 hours from each operator. This estimate remains unchanged from the IFR's estimate.

On August 16, 2017, OMB approved this information collection, ''Reporting Safety-related conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines, and Liquefied Natural Gas Facilities,'' under Control No. 2137–0578, expiring on August 31, 2019. There is no form dedicated to this information collection. Instead, PHMSA will accept safety-related condition reports in a variety of formats by mail or fax. Instructions for filing are in § 191.25, ''Filing safety-related condition reports.''

3. Annual Reporting

PHMSA is finalizing the IFR's amendment to § 191.17, related to annual reporting. Operators must submit data Form 7100.4–1, ''Underground Natural Gas Storage Annual Report,'' no later than every March 15. The annual report must include data from the previous calendar year. For example, the first annual report was due no later than March 15, 2018, and must have included data from the 2017 calendar year. OMB approved this information collection, ''Incident and Annual Reports for Gas Pipeline Operators,'' on August 16, 2017, under Control No. 2137–0522, expiring on August 31, 2020.

In the IFR, PHMSA estimated a reporting burden of 8 hours to complete each annual report form. That estimate included times for reviewing instructions, gathering the necessary data, and responding to each question. However, PHMSA revised the hourly burden estimate from 8 hours to 20 hours per response based on public comments, which are available for review in Docket No. PHMSA–2016–0016.

4. National Registry of Operators and Notification of Changes

This information collection consists of two parts. The first part requires operators to obtain or validate an Operator Identification Number (OPID) from PHMSA. Under the IFR, PHMSA expected to receive 24 OPID requests and 25 ad hoc notifications. PHMSA estimated that each operator would take 1 hour to complete the OPID Assignment form, PHMSA F 1000.1. PHMSA is making no changes to these estimates in this final rule.

The IFR revised § 191.22 to require operators to notify PHMSA, not less than 60 days prior, of certain events. OMB approved this information collection on July 5, 2017, and it will expire on July 31, 2020. PHMSA estimates that this final rule will result in no additional hourly or cost burdens beyond those estimated in the IFR. PHMSA estimates the combined annual burden for OPID Assignment and Operator Notification at 49 hours. (OMB Control No. 2137–0627).

5. Recordkeeping

As discussed throughout this rulemaking, operators must create and maintain records and in accordance with RP 1170 and RP 1171. Operators must also create and maintain written procedure manuals for integrity and program operations. Because of these requirements in the IFR, and codified in this final rule, 136 entities will be required to keep records. PHMSA estimates that it will take operators approximately 1.6 hours annually to maintain the required records. The cost and hourly burden are based on 136 companies with a loaded labor cost of $88 per hour. OMB approved this information collection under OMB Control No. 2137–0634 on October 11, 2018, and it will expire on October 31, 2021. No additional collection or recordkeeping requirements would be imposed on the public by modifying the requirements of this final rule.

L. Privacy Act

In accordance with the Privacy Act of 1974, 5 U.S.C. 552(a), anyone can search the electronic form of all documents received into any of our dockets by the name of the individual submitting the document (or signing the document, if submitted on behalf of an association, business, labor union, etc.). The complete Privacy Act statement is in the **Federal Register** published on April 11, 2000, (65 FR 19477–78), or at the website: *https://www.transportation.gov/dot-website-privacy-policy.*

M. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is the unique identifier for each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. Use the RIN number to find this rulemaking in the Unified Agenda. The RIN number for this rulemaking is RIN 2137–AF22.

List of Subjects

49 CFR Part 191

Underground natural gas storage facility reporting requirements.

49 CFR Part 192

Definitions, Incorporation by reference, Underground natural gas storage facility safety.

49 CFR Part 195

National Registry of Operators.

In consideration of the foregoing, PHMSA is amending 49 CFR parts 191, 192, and 195 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60141; and 49 CFR 1.97.

■ 2. In § 191.1, revise paragraph (a) to read as follows:

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-

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related conditions, annual pipeline summary data, National Registry of Operators information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf, as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

* * * * *

■ 3. In § 191.3, the definitions of ''Incident'' and ''Underground natural gas storage facility'' are revised to read as follows:

§ 191.3 Definitions.

* * * * *

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $50,000 or more, including a loss to the operator and others, or both, but excluding the cost of gas lost; or

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

* * * * *

Underground natural gas storage facility (*UNGSF*) means an underground natural gas storage facility or UNGSF as defined in § 192.3 of this chapter.

■ 4. In § 191.15, revise paragraphs (c) and (d) to read as follows:

§ 191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

* * * * *

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after the detection of an incident required to be reported under § 191.5.

(d) *Supplemental report.* Where additional related information is obtained after an operator submits a report under paragraph (a), (b), or (c) of this section, the operator must make a supplemental report as soon as practicable, with a clear reference by date to the original report.

■ 5. In § 191.17, revise paragraph (c) to read as follows:

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

* * * * *

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4–1. This report must be submitted each year, no later than March 15, for the preceding calendar year.

■ 6. Revise § 191.22 to read as follows:

§ 191.22 National Registry of Operators.

(a) *OPID request.* Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline, pipeline facility, or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must submit an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Operators in accordance with § 191.7.

(b) *OPID validation.* An operator who has already been assigned one or more OPIDs by January 1, 2011, must validate the information associated with each OPID through the National Registry of Operators at *https://portal.phmsa.dot.gov,* and correct that information as necessary, no later than June 30, 2012.

(c) *Changes.* Each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Operators at *https://portal.phmsa.dot.gov* of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction of any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new pipeline;

(iii) Construction of a new LNG plant, LNG facility, or UNGSF; or

(iv) Maintenance of a UNGSF that involves the plugging or abandonment of a well, or that requires a workover rig and costs $200,000 or more for an individual well, including its wellhead. If 60-days' notice is not feasible due to an emergency, an operator must promptly respond to the emergency and notify PHMSA as soon as practicable.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (*i.e.,* with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs;

(ii) A change in the name of the operator;

(iii) A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, UNGSF, or LNG facility;

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to part 192 of this subchapter; or

(v) The acquisition or divestiture of an existing UNGSF, or an LNG plant or LNG facility subject to part 193 of this subchapter.

(d) *Reporting.* An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

■ 7. Revise § 191.23 to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20% or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) In the case of a UNGSF, general corrosion that has reduced the wall thickness of any metal component to less than that required for the well's maximum operating pressure, or localized corrosion pitting to a degree where leakage might result.

(3) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the

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structural integrity or reliability of a UNGSF or LNG facility that contains, controls, or processes gas or LNG.

(4) Any crack or other material defect that impairs the structural integrity or reliability of a UNGSF or an LNG facility that contains, controls, or processes gas or LNG.

(5) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength, or the serviceability or the structural integrity of a UNGSF.

(6) Any malfunction or operating error that causes the pressure of a pipeline or underground natural gas storage facility or LNG facility that contains or processes natural gas or LNG to rise above its maximum well operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

(7) A leak in a pipeline, UNGSF, or LNG facility containing or processing gas or LNG that constitutes an emergency.

(8) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

(9) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG.

(10) [Reserved]

(11) Any malfunction or operating error that causes the pressure of a UNGSF using a salt cavern for natural gas storage to fall below its minimum allowable operating pressure, as defined by the facility's State or Federal operating permit or certificate, whichever pressure is higher.

(b) A report is not required for any safety-related condition that—

(1) Exists on a master meter system or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an UNGSF or an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

(5) Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 8. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60141; and 49 CFR 1.97.

■ 9. In § 192.3, revise the definition of "Underground natural gas storage facility" to read as follows:

§ 192.3 Definitions.

* * * * *

Underground natural gas storage facility (UNGSF) means a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

(1)(i) A depleted hydrocarbon reservoir;

(ii) An aquifer reservoir; or

(iii) A solution-mined salt cavern.

(2) In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

* * * * *

■ 10. Republished § 192.7(b)(10) and (11) continue to read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(b) * * *

(10) API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170), IBR approved for § 192.12.

(11) API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015, (API RP 1171), IBR approved for § 192.12.

* * * * *

■ 11. Revise § 192.12 to read as follows:

§ 192.12 Underground natural gas storage facilities.

Underground natural gas storage facilities (UNGSFs), as defined in § 192.3, are not subject to any requirements of this part aside from this section.

(a) *Salt cavern UNGSFs.* (1) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed after March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, *see* § 192.7), the provisions of section 8 of API RP 1171 (incorporated by reference, *see* § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraphs (c) and (d) of this section prior to commencing operations.

(2) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed between July 18, 2017, and March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, *see* § 192.7) and paragraph (c) of this section prior to commencing operations, and must meet all the provisions of section 8 of API RP 1171 (incorporated by reference, *see* § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.

(3) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1170 (incorporated by reference, *see* § 192.7), sections 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of section 8 of API RP 1171 (incorporated by reference, *see* § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.

(b) *Depleted hydrocarbon and aquifer reservoir UNGSFs.* (1) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed after July 18, 2017, must meet all provisions of API RP 1171 (incorporated by reference, *see* § 192.7), and paragraphs (c) and (d) of this section, prior to commencing operations.

(2) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was

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constructed on or before July 18, 2017, must meet the provisions of API RP 1171 (incorporated by reference, *see* § 192.7), sections 8, 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of paragraph (d) of this section by March 13, 2021.

(c) *Procedural manuals.* Each operator of a UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.

(d) *Integrity management program*—(1) *Integrity management program elements.* The integrity management program for each UNGSF under this paragraph (d) must consist, at a minimum, of a framework developed under API RP 1171 (incorporated by reference, *see* § 192.7), section 8 (''Risk Management for Gas Storage Operations''), and that also describes how relevant decisions will be made and by whom. An operator must make continual improvements to the program and its execution. The integrity management program must include the following elements:

(i) A plan for developing and implementing each program element to meet the requirements of this section;

(ii) An outline of the procedures to be developed;

(iii) The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures required by this paragraph (d);

(iv) A plan for how staff will be trained in awareness and application of the procedures required by this paragraph (d);

(v) Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and

(vi) A plan for how to incorporate information gained from experience into the integrity management program on a continuous basis.

(2) *Integrity management baseline risk-assessment intervals.* No later than March 13, 2024, each UNGSF operator must complete the baseline risk assessments of all reservoirs and caverns, and at least 40% of the baseline risk assessments for each of its UNGSF wells (including wellhead assemblies), beginning with the highest-risk wells, as identified by the risk analysis process. No later than March 13, 2027, an operator must complete baseline risk assessments on all its wells (including wellhead assemblies). Operators may use prior risk assessments for a well as a baseline (or part of the baseline) risk assessment in implementing its initial integrity management program, so long as the prior assessments meet the requirements of API RP 1171 (incorporated by reference, *see* § 192.7), section 8, and continue to be relevant and valid for the current operating and environmental conditions. When evaluating prior risk-assessment results, operators must account for the growth and effects of indicated defects since the time the assessment was performed.

(3) *Integrity management re-assessment intervals.* The operator must determine the appropriate interval for risk assessments under API RP 1171 (incorporated by reference, *see* § 192.7), subsection 8.7.1, and this paragraph (d) for each reservoir, cavern, and well, using the results from earlier assessments and updated risk analyses. The re-assessment interval for each reservoir, cavern, and well must not exceed seven years from the date of the baseline assessment for each reservoir, cavern, and well.

(4) *Integrity management procedures and recordkeeping.* Each UNGSF operator must establish and follow written procedures to carry out its integrity management program under API RP 1171 (incorporated by reference, *see* § 192.7), section 8 (''Risk Management for Gas Storage Operations''), and this paragraph (d). The operator must also maintain, for the useful life of the UNGSF, records that demonstrate compliance with the requirements of this paragraph (d). This includes records developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any integrity management program element.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 12. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60116, 60118, 60132, 60137, and 49 CFR 1.97.

■ 13. In § 195.64:

■ a. Revise the section heading;

■ b. Remove ''National Registry of Pipeline and LNG Operators'' and add ''National Registry of Operators'' in its place everywhere it appears; and

■ c. Remove the website address ''*http://opsweb.phmsa.dot.gov*'' in paragraphs (b) and (c) and add ''*https://portal.phmsa.dot.gov*'' in its place.

The revision reads as follows:

§ 195.64 National Registry of Operators.

* * * * *

Issued in Washington, DC, on January 10, 2020, under authority delegated in 49 CFR 1.97.

Howard R. Elliott,

Administrator.

[FR Doc. 2020–00565 Filed 2–11–20; 8:45 am]

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Ex. I - 4

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

API RECOMMENDED PRACTICE 1171
FIRST EDITION, SEPTEMBER 2015

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Foreword

API Recommended Practice 1171 applies to gas storage in depleted hydrocarbon reservoirs and aquifers. Gas storage in solution-mined salt caverns is not addressed, since API 1170 [1] applies to natural gas storage in solution-mined salt caverns.

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Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

1 Scope

This recommended practice (RP) applies to natural gas storage in depleted oil and gas reservoirs and aquifer reservoirs, and focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operation, monitoring, maintenance, and documentation practices. The scope does not include pipelines, gas conditioning and liquid handling, compressors, and ancillary facilities associated with storage. Storage design, construction, operation, and maintenance include activities in risk management, site security, safety, emergency preparedness, and procedural documentation and training to embed human and organizational competence in the management of storage facilities. This RP embodies historical knowledge and experience and emphasizes the need for case-by-case and site-specific conditional assessments.

This RP applies to both existing and newly constructed facilities. However, Sections 5 and 7 apply exclusively to new facilities and facilities undergoing expansion, and Section 6 applies to new well construction and remediation of a new or existing well. Figure 1 provides a chart showing the flow of functional integrity assurance activities through the design, operation, and maintenance of storage facilities, with references to the sections within this RP containing guidance for those activities. Applicable distinctions for aquifer facilities are identified within each section as necessary. "Replacement," as used in this document, refers to the complete replacement of a facility unit, as, for example, when an existing well is abandoned and replaced with a new well. This document recommends that operators manage integrity through monitoring, maintenance, and remediation practices and apply specific integrity assessments on a case-by-case basis.

The contents of this RP are not all inclusive or intended to replace the utilization of detailed information and procedures found in textbooks, manuals, technical papers, or other documents.

This document is intended to supplement, but not replace, applicable local, state, and federal regulations.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 5A3, *Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements*

API Recommended Practice 5C1, *Recommended Practice for Care and Use of Casing and Tubing*

API Technical Report 5C3, *Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing*

API Specification 5CT, *Specification for Casing and Tubing*

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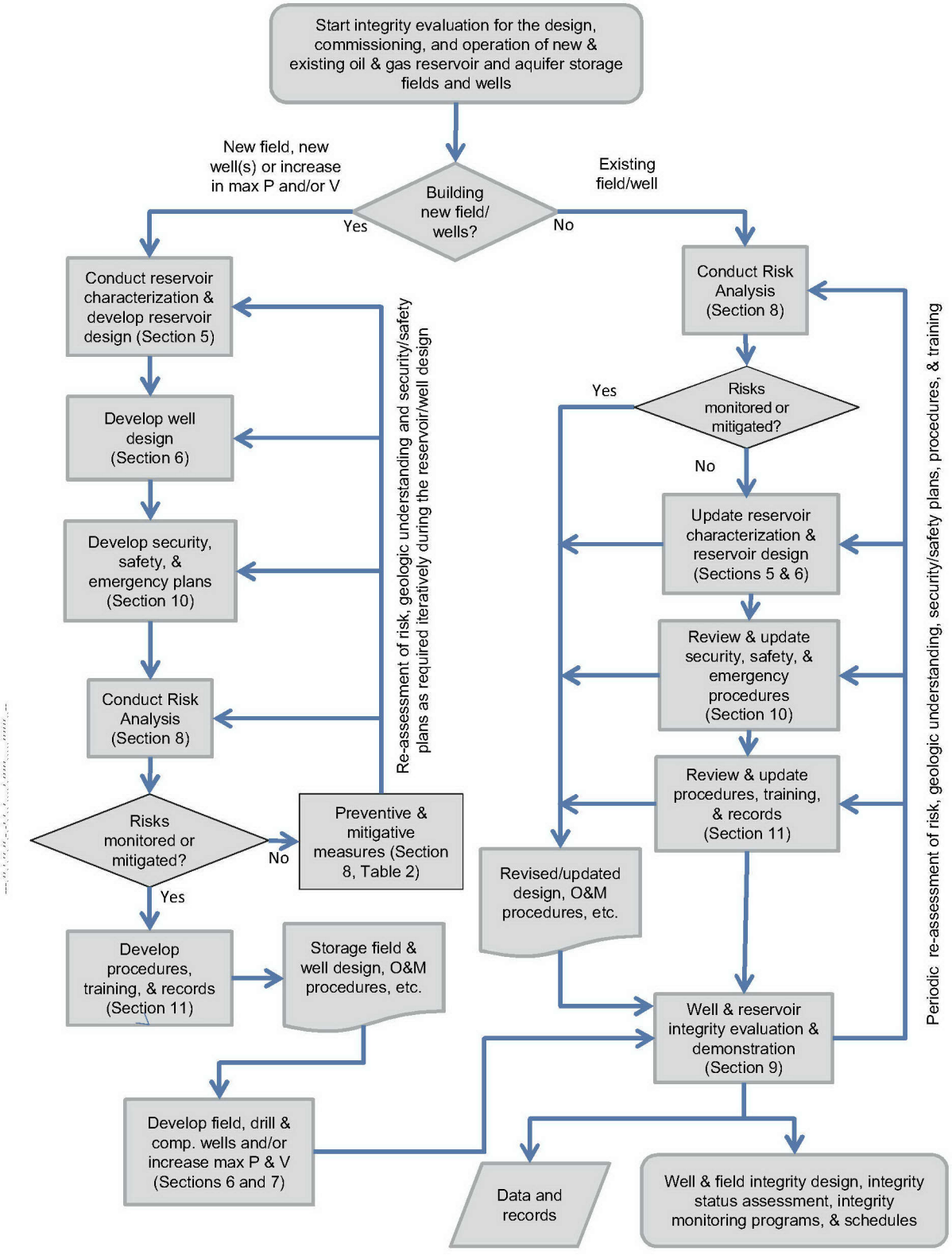

Figure 1—Flow Chart of Document Sections

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3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply. The definitions emphasize the use of the terms in the context of functional integrity.

3.1.1
abnormal operating condition
Condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

a) indicate a condition exceeding design limits; or

b) result in a hazard(s) to persons, property, or the environment; or

c) indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well and/or the reservoir.

3.1.2
aquifer pressure
Current pressure in the infinite-acting aquifer attached to an aquifer storage reservoir at a distance not influenced by the storage operation and to which a gas storage reservoir would eventually return if given a long enough shut-in period.

3.1.3
aquifer reservoir storage
Porous and permeable rock media originally filled with water and converted to gas storage.

3.1.4
average (shut-in) reservoir pressure
Pressure of the reservoir based on an average of well pressures in a shut-in condition of no active injection or withdrawal of storage gas.

NOTE Due to the dynamic pressure conditions in a typical gas storage reservoir and/or operational limitations on field shut-in periods, the average reservoir pressure can be extrapolated or assumed based on well pressures from a key indicator well(s) (see **key indicator well**).

3.1.5
basal rock
Rock layer(s) that forms a vertical seal (barrier) to fluid flow at the lower boundary of a storage reservoir.

3.1.6
base gas
[cushion gas]
[pad gas]
Volume of gas needed in a storage reservoir to maintain reservoir pressure to cycle the working storage volume and meet required deliverability rates.

3.1.7
buffer zone
Area or interval outside the defined gas storage reservoir, horizontally and/or vertically, where nonstorage drilling or subsurface operations are restricted to provide protection of the storage reservoir from encroachments and losses.

NOTE Buffer zones accommodate geologic uncertainties in the exact location of the storage reservoir boundaries.

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3.1.8
caprock
Rock layer(s) acting as the vertical seal (barrier) preventing migration of fluids at the upper boundary of the storage reservoir.

3.1.9
caprock threshold displacement pressure
Minimum pressure difference between the gas pressure at the face of the caprock and the water phase pressure immediately above the gas-water interface within the caprock, at which the gas starts to move continuously through the caprock.

3.1.10
cement plug
Cement that is placed in the wellbore with a defined bottom and top to achieve zonal isolation within the wellbore and to prevent communication of fluids between zones by providing a mechanical seal.

3.1.11
collector formation
Formation, usually vertically above the gas storage reservoir, capable of trapping and accumulating gas.

3.1.12
communication
Fluid movement influence, which may be detected by pressure observation, fluid physical and chemical composition analysis techniques, or other means.

3.1.13
containment
Ability of a reservoir to confine stored gas and prevent migration either laterally or vertically out of the reservoir.

3.1.14
contractor personnel
Person or entity utilized by the operator but not directly employed by the operator.

3.1.15
encroachment
Intrusion of a nonstorage well or operations into the defined surface and/or subsurface storage area threatening the integrity of the storage operations.

3.1.16
functional integrity
Total reliability of the storage system, including the physical integrity of the reservoir and well components and the performance reliability assurance established by management systems employed by the storage operator.

3.1.17
groundwater
Subsurface fresh water, potable water, or water that is or can be potentially used as a drinking water supply.

3.1.18
inventory verification
Procedure for confirmation or accounting of total gas present within the storage reservoir at a given time to reconcile with measured volumes and total inventory.

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3.1.19
inventory, total
Total gas volume within the storage reservoir.

NOTE The total inventory at any given time can be determined by an initial determination of gas in place and adjusting that volume for production, fuel, and field use or other losses during production operations; cumulative storage injection and withdrawal activity; and storage operations fuel, field use, or other losses and adjustments.

3.1.20
key indicator well
Shut-in storage well that is representative of the average reservoir pressure of the active gas storage area.

NOTE Key indicator well pressure can be used to develop the pressure-inventory relationship of the gas storage reservoir.

3.1.21
master meter
Gas measurement point(s) in the gas storage facility where accurate gas measurement is made of the full gas flow into or out of the entire storage facility.

3.1.22
maximum cycling capacity
Maximum amount of working gas volume able to be withdrawn and injected over the time of a complete design cycle from maximum to minimum pressures within the reservoir.

3.1.23
maximum reservoir pressure
Average stabilized shut-in reservoir pressure at maximum design capacity of gas in storage.

3.1.24
mechanical integrity
Quality or condition of a well in being structurally sound with competent pressure seals by application of technical, operational, and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.

3.1.25
mechanical integrity test
Procedure that obtains data that demonstrates if a well is mechanically fit for service and capable of storing natural gas within design limitations.

3.1.26
minimum reservoir pressure
Average stabilized shut-in reservoir pressure at minimum design capacity of gas in storage.

3.1.27
native gas
Unproduced gas indigenous to the reservoir that remains in the reservoir at the time of conversion to storage.

3.1.28
observation well
Well that functions as a pressure and fluid monitoring point, located within, above or below, or laterally adjacent to the active storage reservoir, and generally not used to inject or withdraw storage gas.

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3.1.29
plan
Documented explanation of the mechanisms or procedures used to implement a program and to achieve compliance with standards.

NOTE A specific well work plan for drilling, completion, servicing, or workover operations can be written step-by-step instructions and associated information (cautions, notes, warnings) that describe how to safely perform a task.

3.1.30
pound-days
Empirical method of estimating the aquifer response to gas injection and withdrawal cycling.

NOTE 1 Net pound-days are calculated by summing the differences in daily reservoir pressure, in pounds per square inch, above (plus) or below (negative) the aquifer pressure over the period of an injection and withdrawal cycle.

NOTE 2 The pound-days calculation can be used in hydrocarbon reservoir storage applications as well as aquifer reservoir storage applications.

3.1.31
pressure cycling
Cyclic variations in reservoir pressure due to the injection and withdrawal of gas.

NOTE In reservoir gas storage operations, pressure cycling often occurs over a one-year period with injections in the summer and withdrawals in the winter; however, storage operations may involve any number, timing, and amplitude of pressure cycles.

3.1.32
pressure-inventory relationship
Correlation between reservoir pressure and total gas inventory over time.

NOTE The data to trend the relationship can be derived from well pressure observations and total inventory.

3.1.33
procedure
Documented explanation of action taken to achieve the steps of a process.

NOTE Procedures can be a description of the execution of tasks in a method or linked set of methods that will enable the activity to be accomplished according to a set of guidelines and standards.

3.1.34
process
Systematic, ordered series of events directed to some end that comprise an approach or methodology to achieve an objective

NOTE A process can describe work flow activity and quality standards for a wide range of procedures.

EXAMPLE The risk management process is a systematic application of management policies, procedures, and practices to the activities of communicating, consulting, establishing the context, and identifying, evaluating, monitoring, and reviewing risk.

3.1.35
program
Overall approach to manage a functional activity or physical part of an asset.

NOTE A program can be a defined outline of work activities that are designed to address specific objectives. Programs identify what to do and why it needs to be done. The program can define important aspects such as purpose and scope, roles and responsibilities, tasks and procedures, and anticipated results and work products.

3.1.36
spill point
Point or area in a hydrocarbon trap at which the trap can be breached.

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NOTE The spill point may be related to geologic structure, permeability, fluid density, pressure, and viscosity, or any combination of those features.

3.1.37
wellhead
Surface equipment used to maintain control of the well, including the connecting casing head, tubing head, and Christmas tree.

3.1.38
working gas
[top gas]
[current gas]
Volume of gas in the reservoir above the designed level of base gas.

3.1.39
zonal isolation
Condition of no communication between the gas storage formation and other formations in a wellbore or between the wellbore and any formation intended to be isolated.

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

H_2S	hydrogen sulfide
MOC	management of change
O&M	operations and maintenance
pH	hydrogen ion potential
P&M	preventive and mitigative
Tcf	trillion cubic feet

4 General Principles of Underground Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

4.1 General

This section provides general background into the functions, history, and geotechnical aspects of underground natural gas storage.

4.2 Functions of Underground Natural Gas Storage

Natural gas storage utilizes depleted hydrocarbon and aquifer reservoirs selectively located where geology is suitable. The natural gas storage reservoirs are connected into the natural gas infrastructure via pipelines. Residential and commercial heating and cooling, value arbitrage, swing service between pipelines, and load-following service to electric generation create fluctuations in gas demand. The fluctuations in natural gas demand versus the relative consistency of natural gas supply are managed by underground natural gas storage. Underground natural gas storage facilities function to smooth out the disparity between supply and demand during these peak demand periods. Without storage, serving demand fluctuations would require wide swings in the sources of gas supply, which could negatively impact ultimate gas recovery. Furthermore, without the integration of storage facilities into the pipeline system, the capacity of the pipeline network would need to be much greater to accommodate the highest flow rates to the markets during peak demand periods. Gas supply and transportation can be more efficient with storage available to the pipeline system.

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4.3 History of Underground Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

Natural gas has been stored underground in depleted hydrocarbon reservoirs in the United States since 1916 when the Zoar Field in western New York was first used for storage. As of 2015, there are more than 350 active gas storage reservoirs in the United States and Canada using depleted hydrocarbon reservoirs. These facilities represent over 16,000 reservoir-years of operation (i.e. sum of operating years of each of the 350 reservoirs), store over 7.8 Tcf of natural gas at maximum capacity, and are accessed and monitored by more than 14,200 wells.

Aquifer reservoir storage dates back to 1946. As of 2015, there are 51 operating aquifer storage reservoirs in the United States and Canada representing over 2,300 reservoir-years of operation, with a maximum inventory capacity of 1.3 Tcf, accessed and monitored by more than 2,600 wells.

4.4 Geotechnical Aspects of Underground Natural Gas Storage

Natural gas is stored underground in areas where porous and permeable rock is available and can contain the injected natural gas. Underground porous zones are typically fluid-filled in their native state and the fluid can be hydrocarbons (oil, gas) and/or water. Once the hydrocarbons are depleted, the porous zone can be used for natural gas storage. Alternatively, the porous zone may be filled with only water, which does not necessarily require any depletion before it can be converted for use as a natural gas storage reservoir. It is also possible to excavate or solution-mine caverns into otherwise impermeable rock for the storage of gases and liquids. API 1170 applies to natural gas storage in solution-mined salt caverns.

Depleted hydrocarbon reservoirs are candidates for natural gas storage because the reservoir integrity has been demonstrated over geologic time by hydrocarbon containment at initial pressure conditions. Depleted hydrocarbon reservoirs generally have available rock data, reservoir engineering data, and fluid compositional data from their production history. The storage suitability of a hydrocarbon reservoir requires investigation on an individual basis, using a number of means to evaluate reservoir integrity, well integrity and fluid chemistry.

In regions where depleted hydrocarbon reservoirs are not present, aquifers exhibiting the qualities of a hydrocarbon reservoir may be available. Aquifer reservoirs are similar to depleted hydrocarbon reservoirs in terms of the nature of the porous rock media used to contain the gas and the methodology for assessing the reservoir. The storage suitability of an aquifer reservoir requires investigation on an individual basis, using a number of means to evaluate reservoir integrity, well integrity, and fluid chemistry.

There is no ideal depth, rock type, or trapping mechanism; each reservoir requires site-specific evaluation. The gas trapping mechanism depends on rock porosity and permeability controls, hydrodynamics, and geologic structural controls. The top of the reservoir is sealed by impervious rock referred to as its “caprock.” The bottom of the reservoir and lateral boundaries are sealed by structural closure, decrease or loss of porosity and permeability, or hydrodynamic forces. The containment of stored gas can be managed by means of facility and operational controls when geologic boundaries are less than ideal.

Gas storage reservoirs are monitored over their operating lifetime to evaluate functional integrity and management of gas containment. Monitoring includes protecting the reservoir from potential integrity threats brought on by third-party drilling, hydrocarbon production, and mining operations.

The reservoir is accessed via wells drilled either vertically or directionally from the surface. The wells are connected to a surface pipeline network that transports the gas to and from a central station, where gas separation, dehydration, metering, and compression facilities are commonly located. New gas storage wells are constructed for a long useful life to withstand cyclic pressure and temperature conditions. Existing wells used in storage operations undergo mechanical integrity evaluations prior to conversion to ensure safety under storage operating conditions. Gas storage wells are monitored and maintained over their operating lifetime to evaluate the containment capability of the fluids at the pressures and flow rates expected.

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5 Functional Integrity in the Design of Natural Gas Storage Reservoirs

5.1 General

This section addresses the requirements for the assessment and design of new natural gas storage capacity development in hydrocarbon production reservoirs and aquifer reservoirs, and increased maximum pressure and/or total capacity in existing natural gas storage reservoirs. The assessment steps are arranged generally in order of increasing effort and resources, beginning with utilization of available data and progressing to data gathering and testing.

5.2 Geological Reservoir Characterization

5.2.1 General

The goal of the baseline geological reservoir characterization is to develop a practical understanding of the suitability of the reservoir and the adjacent geologic stratigraphic environment prior to storage development or expansion.

5.2.2 Geological Characterization

A preliminary evaluation of the extent and properties of the porous rock interval, or reservoir, intended for storing natural gas, and the confinement mechanisms to contain the hydrocarbon accumulation in the reservoir, shall be conducted, characterized, and presented in the form of geologic mapping and analysis. The geologic characterization uses available data, which can be obtained from various sources, including published literature, regulatory agencies, production operators, academic institutions, and commercial data providers, to provide a basis that can be refined by engineering reservoir characterization and supplemental data gathering.

The geologic characterization shall be used to establish the initial vertical and areal buffer zone in order to protect the integrity of the natural gas storage operation. Once a reservoir is in operation, the findings of ongoing reservoir performance monitoring programs may require that the buffer zone be reviewed and revised as necessary to protect and maintain the integrity of the storage reservoir.

The scope of the geologic characterization should encompass the intended reservoir rock and sealing mechanisms, the vertical interval above and below the intended reservoir, areas where gas could potentially migrate, and the areas adjacent to the intended reservoir where potential entrapment of migrated gas could occur. The depths of groundwater and locations of surface waters should be delineated. Locations of abandoned wells, underground disposal horizons, mining, and other industrial activities should be mapped. Surface topography and land use should be included in the evaluation where topography and land use may impact storage surface facilities and/or subsurface integrity.

The reservoir rock itself should be characterized including its lithology, geo-mechanical competency, porosity, permeability, homogeneity, isotropy, and residual pore fluid saturations. Reservoirs that have proven suitable for natural gas storage include structural and stratigraphic entrapments within porous and permeable rock, which could have a connection to a regional aquifer, or a hydrodynamic entrapment in a structural feature within a regional aquifer. A competent and impermeable caprock, located above the intended gas-filled reservoir, should be identified and evaluated for controlling the upward movement of the stored natural gas. The basal and lateral sealing mechanisms should be identified and evaluated for controlling movement of the stored gas.

Available data such as drilling data, logs, fluid samples, cuttings and core data from existing hydrocarbon and water wells, or other geophysical data such as seismic, gravity, and magnetic surveys should be used for the geological characterization. The quantity and quality of data used in the geologic characterization should be evaluated throughout the design phase to determine the need for supplemental data gathering, either prior to or during construction. The design should address alternative geological characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternative interpretations.

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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.

5.3 Engineering Reservoir Characterization

5.3.1 General

The engineering characterization expands upon the geological characterization. The goal is to understand, prior to storage development or expansion, the probable response of the reservoir and adjacent areas to the proposed pressure cycling and flow rates.

5.3.2 Engineering Characterization

The scope of the engineering reservoir characterization should incorporate the vertical and areal bounds of the geological characterization, and include examination of any anomalous geological features, if possible. The engineering characterization may suggest that the scope of the geologic characterization should be modified or expanded.

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. At a minimum, casing materials, casing configuration, casing set depths, cement materials, and placement depths shall be evaluated for effective mechanical 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.

Reservoir pore fluid chemistry and physical properties should be characterized, particularly in gas-liquid and oil production reservoirs and in reservoirs containing impurities exceeding pipeline gas quality specifications. The chemical and physical properties of pore water should be characterized, particularly for aquifer reservoirs intended for natural gas storage. Corrosive potential of the pore fluids shall be determined and corrosion management shall be incorporated into design and operation strategies. Potential mineralogical and fluid compatibility issues with anticipated drilling or treating chemicals and liquid mixtures shall be identified and mitigated.

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. At a minimum, initial and current reservoir pressure shall be identified. For existing storage fields being considered for expansion, prior gas storage operational records should be analyzed in order to evaluate the interaction of the gas storage operation with the rock-fluid system of the reservoir. For aquifer reservoirs, available water well test data should be analyzed. 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.

Anomalous locations of hydrocarbons or pressure found in the historic data review can indicate mechanical integrity issues related to existing wells, or that the reservoir characterization is inaccurate. Potential mechanical integrity issues should be identified for further investigation as appropriate.

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5.4 Containment Assurance of Reservoir Design

5.4.1 General

Data shall be acquired to provide the design necessary to eliminate or manage uncertainties identified by the geologic and engineering reservoir characterization. The operator shall assess containment capability of the reservoir and the wells for the design storage operation volumes, pressure, and rates of withdrawal and injection. 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.

5.4.2 Reservoir Connectivity

In cases where connectivity with another porous zone is indicated but can be accommodated without loss of functional integrity, the design shall address the gas migration control and containment risk mitigation methodology, such as gas recovery, pressure limitations, zonal control, and expansion of the vertical and lateral dimensions of the buffer zone.

5.4.3 Maximum and Minimum Pressure

The operator shall document the design basis for maximum reservoir pressure.

NOTE The design basis can employ analysis of fracture gradient, water gradient, initial pressure, caprock permeability, caprock threshold displacement pressure, geo-mechanical testing, or other means.

The pressure required to inject intended gas volumes, particularly at total inventory, shall not exceed the design pressure limits of the reservoir, wells, wellheads, piping, or associated facilities.

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.

5.4.4 Well Penetrations

Wells completed in or penetrating through the intended storage reservoir, caprock, and basal rock shall be evaluated for containment assurance for the design storage operation volumes, pressure, and flow rates. The operator should identify wells that may require integrity testing and/or well logging in order to meet the integrity demonstration requirements of 7.2. Selected plugged wells may be re-entered, examined, and replugged or monitored to manage identified containment assurance issues.

5.4.5 Supplemental Evaluation

Supplemental reservoir geological and engineering evaluation shall be required for the delineation of potential reservoirs to be developed within aquifers. Characterization of the potential extent of the aquifer and its potential or probable influence on the storage reservoir operation should be determined. Well drilling, logging, and coring shall be performed to gather data and analyze characteristics of the reservoir, caprock, basal rock, and lateral seals. Site-specific geophysical delineation shall be performed, including drilling of test wells and observation wells, and identification of reservoir closure, spill points, and vertical containment. Water pump testing and water level

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observation shall be performed in order to characterize reservoir dimensions, gas capacity, flow performance, and caprock integrity.

Supplemental geological characterization may be performed for hydrocarbon reservoirs having a minimal amount of existing and available geologic data or if undrilled potential entrapments are indicated nearby from the initial evaluations. Additional targeted geophysical surveying or geologic data collection may be obtained.

5.4.6 Other Design Factors

Design factors to protect the mechanical integrity of the storage facilities should include:

a) analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures; and

b) analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.

5.4.7 Facility Integrity Plan

The operator should develop a facility integrity plan that covers the storage facility. The facility integrity plan documents work performed during a containment assurance analysis detailed in this subsection, identifies required integrity work and implementation schedule during and after construction, identifies integrity monitoring required during commissioning as detailed in Section 7, and identifies operations monitoring requirements detailed in Section 9 and Section 11.

NOTE The facility integrity plan can be in the form of a standard plan used by the operator for multiple natural gas storage facilities or a site-specific plan.

5.5 Environmental, Safety, and Health Considerations in Design

5.5.1 Design and Construction Safeguards

Safeguards to the environment, safety, and health of workers and the public shall be incorporated into natural gas storage design.

NOTE Publications such as API 51R [2] and API 76 [3] can be referenced to identify safeguards for application in natural gas storage design.

The operator shall incorporate protection of surface water and groundwater resources in the design of storage facilities. The operator should conduct an environmental impact review prior to well drilling and facility construction.

The design of natural gas storage facilities shall incorporate plans for monitoring worksite conditions related to storage development and well drilling in order to protect the environment and the safety and health of workers and the public.

5.5.2 Operation and Maintenance Safeguards

The operator should design for long-term viability and functional integrity of the storage facility in order to promote the ability to maintain and operate the storage facility consistent with environmental regulations and to maintain worker and public safety throughout the life of the storage facility.

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5.6 Recordkeeping

Accurate and comprehensive records of natural gas storage design activities shall be maintained for the life of the facility. The records shall include, as applicable and available:

— geologic records such as well logs, cuttings reports, core reports, geophysical records, and maps;

— engineering records such as historic hydrocarbon production data, data gathered during aquifer and hydrocarbon reservoir characterization, reservoir design data, and gas storage reservoir operational data;

— documents related to storage land and mineral ownership, rights, and control;

— facility integrity plan;

— well drilling, completion, workover, and plugging records for wells analyzed for the design and for proposed well actions during project construction; and

— regulatory records including permit applications, permits, reports, and correspondence.

6 Functional Integrity in the Design and Construction of Natural Gas Storage Wells

6.1 General

This section addresses the requirements for functional integrity in the design, construction, and completion of new natural gas storage wells, the remediation and reconditioning of existing wells, and abandonment of wells within a natural gas storage facility.

6.2 Wellhead Equipment and Valves

6.2.1 General

New or replacement wellhead equipment, including associated fittings, flanges, and valves, should conform to API 6A [4].

6.2.2 Wellhead Equipment Design

New and replacement wellheads shall allow for full-diameter entry to the wellbore. As part of the planning for well maintenance, the operator shall review the well records to determine if limited or less-than-full-diameter access situations are sufficient to allow for the planned activities.

A well shall be equipped with valves to provide isolation of the well from the pipeline system and to allow for entry into the well.

NOTE The pipeline isolation valve, as defined by the operator, can be a pipeline jurisdictional or regulated valve.

EXAMPLE In the United States, the requirements for the pipeline isolation valve are defined in 49 *CFR* 192.145 [5].

All ports on the wellhead assembly above the casing bowl should be equipped with valves, blind flanges, or similar equipment.

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6.2.3 Pressure Rating

Wellhead equipment shall have operating pressure ratings sufficient to exceed the maximum anticipated operating pressure. In addition, the wellhead design should include evaluation of the following:

— treating and stimulation pressures;

— flow rates;

— fluid chemical composition of produced fluids and fluids used in well stimulation;

— possible solids production;

— possible increases in the maximum operating pressure;

— intended flow path; and

— accommodation for pressure and/or temperature monitoring of tubular and annular spaces.

6.2.4 Existing Equipment

Existing wellhead equipment is accepted if it has demonstrated containment of maximum operating pressure, but shall be further evaluated for suitability before increasing the operating pressure beyond the historical maximum.

6.2.5 Emergency Shutdown Valves

Automatic or remote-actuated emergency shutdown valves (wellhead, side-gate, or subsurface) are not required for most storage wells; however, the operator shall evaluate the need for any type of emergency shutdown valve by reviewing the following:

— distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people assemble such as campgrounds, recreational areas, or playgrounds;

— gas composition, total fluid flow, and maximum flow potential;

— distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;

— added risks created by installation and servicing requirements of safety valves;

— risk to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;

— alternative protection measures that could be afforded by barricades or distance or other measures; and

— present and predicted development of the surrounding area, topography, and regional drainage systems and environmental considerations.

NOTE API 14A [6] and API 14B [7] provide guidance (for design, installation, and testing) when a subsurface safety valve is used. Testing of safety valves is discussed in 9.3.

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6.3 Well Casing

6.3.1 General

A well shall be completed with two or more strings of casing as needed to:

— protect groundwater;

— control wellbore conditions;

— isolate the storage gas within the storage reservoir; and

— inject storage gas from the pipeline into and withdraw out of the storage reservoir to the pipeline.

Each string of casing shall be designed in accordance with API 5C3 in order to safely contain the internal casing pressures and withstand the external casing (formation) pressures through the setting depth. The operator should determine its own guidelines for establishing safety factors for use with API 5C3 calculations, recognizing minimum design safety factors that may be dictated by applicable regulations.

6.3.2 Conductor Casing

The conductor casing should be of sufficient size and grade to support subsequent drilling operations.

6.3.3 Surface Casing

The surface casing shall be of sufficient size, grade, and depth to support subsequent drilling operations and to protect groundwater.

NOTE When, due to geologic conditions, a supplemental string of casing is necessary before the surface casing point is reached, the supplemental casing is considered an intermediate casing string for purposes of this standard.

6.3.4 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. Placement may be stipulated by applicable regulations.

6.3.5 Production Casing

The production casing, which provides access to the storage interval, shall be of adequate size and strength to maintain the well integrity and be compatible with fluid chemical composition.

The production casing should be designed to accommodate fluids on injection and withdrawal at the maximum expected pressures and velocities.

NOTE API 14E [8] provides guidance for velocity calculations and limitations.

The production casing shall be free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work shall be sealed to establish hydraulic isolation.

6.3.6 Handling

Casing shall be stored, transported, lifted and installed as specified by the manufacturer and in accordance with API 5C1.

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6.3.7 Connections

Casing connections shall be designed to accommodate loads associated with placement. The operator should calculate the expected mechanical load conditions for casing in the vertical and/or directionally oriented conditions during running, cementing, drilling, and operations and design the casing to have mechanical properties in excess of the mechanical load conditions. The casing shall maintain a gas seal under anticipated wellbore flow conditions and subsequent work in the wellbore (drilling, stimulation, and remediation).

Casing connections shall be made up according to manufacturer specifications or in accordance with API 5CT.

Thread compound or lubricant shall be compatible with the expected wellbore environment and shall be consistent with the manufacturer's recommended lubricant or API 5A3.

6.4 Casing Cementing Practices

6.4.1 General

The purpose of cement in the construction of a new or reworked natural gas storage well is to maintain the integrity of the storage reservoir by providing isolation of the reservoir from communication with other sources of permeability or porosity through the drilled wellbore. In new construction, isolation is accomplished by filling the annular space between the casing and formation with competent cement to create a seal so that communication of fluids between the wellbore and the storage zone or other zones of interest is prevented.

6.4.2 Cement Quality

Cement should meet quality standards in API 10A [9] and ASTM C150/C150M [10] or exceed the requirements set in these standards.

6.4.3 Cement in Well Construction and Remedial Work

Properly designed and placed cement has several important functions in the construction, remediation, and plugging of gas storage wells to provide wellbore and reservoir integrity.

Conductor Pipe—When conductor pipe is placed in a drilled hole, the operator should cement the pipe in place, and the cement slurry should be designed for sufficient volume to circulate the cement to the surface.

NOTE Driven conductor pipe does not require cementing.

Surface Casing—The cement slurry design should provide for a volume in excess of the annular volume and, if technically feasible, with sufficient volume to circulate the cement to the surface to provide support for the wellhead and casing strings and isolate groundwater from communication with fluids from other sources.

Intermediate Casing—The operator should use cement slurry designed for the anticipated wellbore conditions. Cement should be designed for sufficient volume to circulate the cement to the surface when possible. Where it is not possible to circulate cement to surface, the operator should design the cementing program such that the cement top would be at a point within the surface casing to establish zonal isolation.

Production Casing and Liners—The operator shall use cement slurry or slurry combinations designed for hydrostatic weight control and strength requirements. The production casing cement should be designed for sufficient volume to:

— circulate the cement to the surface, or

— circulate to a point within the next casing string, or

— establish the zonal isolation of permeable zones.

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Cement slurry used for cement plugs can be relatively small in volume and be subject to contamination by wellbore fluids; operators should design plug slurry composition and plug setting techniques to minimize the chance for contamination, as such contamination could result in weak, diluted, nonuniform, or unset cement plugs. Cement slurry for plugs should be designed for both cement blend and placement to have mechanical and isolation properties for the proposed use and functional objectives.

Remedial cementing procedures are used to squeeze cement outside of the casing in order to restore wellbore integrity, seal off communicating zones, or to provide zonal isolation. The operator should design the remedial cement slurry and placement technique for the specific wellbore conditions, formations, and type of repairs, such that isolation of the storage zone from all other sources of porosity and permeability is achieved.

6.4.4 Cement Slurry Design and Controls

A successful cement job is designed for the specific conditions of each well with controls established to enable the cement slurry to perform as designed. When designing a cement slurry, the operator should review information such as the historical success of cement slurry composition at achieving isolation objectives in nearby wells, the type of formations, temperature, and requirements such as water ratio, desired compressive strength, prevention of contamination by formation fluids, and various additives to control fluid rheology and reaction time.

NOTE 1 Conditions can exist that require special evaluation in the design of the cement such as highly porous formations, salt formations, coal formations, mine voids, corrosive formations, washouts, multi-stage cementing, or intermediate casing strings.

The equivalent circulating density of the cement pumping operation shall be designed such that the fracture gradient of the storage zone is not exceeded and such that lost circulation potential of any exposed zone is minimized.

Cement volumes in excess of the calculated or measured requirement may be used when required to circulate cement to surface.

NOTE 2 Caliper logging can provide information to improve casing-borehole annular volume calculation when wellbore caving or enlargement is suspected.

Laboratory testing may be conducted to confirm that the cement blend meets design requirements.

Each source of mix water may be tested for pH and temperature prior to mixing to confirm that the cement blend meets design requirements.

Representative slurry samples should be obtained from each cement blend pumped and held for further analysis.

The cement cure time should be determined and time should be allowed for the cement to develop compressive strength before the casing is disturbed or differential stress is placed upon the casing.

6.4.5 Cement Pumping Design

The proper placement of the cement slurry provides well integrity by isolating the reservoir from communication with other sources of potential fluid flow.

Prior to cementing a casing string, the operator should condition the fluid in the wellbore to improve the fluid mobility, assist in fluid displacement by the cement slurry, and achieve good cement bonding with the casing and formation.

NOTE 1 API 65-2 [11] provides guidance on conditioning the fluid in the wellbore.

The operator should use spacers and/or preflushes to help remove any mud cake that may exist. The spacers should isolate dissimilar fluids to prevent potential cement contamination problems.

NOTE 2 The spacers and preflushes are often weighted to prevent fluid entry during the precementing cleaning process.

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The casing should be centralized in the wellbore to prevent cement channeling, especially in and near zones where good cement bonding is critical. The impact of wellbore inclination should be evaluated when designing the placement and spacing of centralizers. The operator should address geologic conditions and hole deviation conditions that require additional evaluations for casing centralization design.

NOTE 3 Casing centralization aids in the removal of drilling fluids behind the pipe during the cement slurry pumping process and thereby improves the uniform flow of cement up the annulus. API 10D-2 [12] and API 10TR4 [13] provide guidance. Cementing service company technical experts provide guidance and recommendations.

Where known formation and wellbore conditions present a risk to zonal isolation through cementing practices alone, the operator may use external casing packers or other isolation equipment in the design of the cement job.

A guide shoe should be installed on the first joint of the production casing to avoid ledges, prevent sidewall caving, and prevent damage to the bottom of the casing while running the casing in the well.

A float collar or other equivalent device should be installed one or more pipe joints from the bottom of the casing to prevent backflow, reduce derrick stress, and prevent contaminated cement from reaching the shoe.

Competent, uncontaminated cement shall be placed around the casing shoe and around the circumference of the casing in order to meet the requirements of 6.4.3.

A wiper or cementing plug should be used during the cementing of the production casing to reduce the potential for contamination of the cement and help control displacement volumes.

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 movement or disturbance until the cement has been allowed to develop initial compressive strength.

NOTE 4 Casing scratchers can promote cement bonding by assisting in mud cake removal when using pipe movement.

Cement pumping and mixing equipment should be appropriate for the pressures and rates required for the job and should be capable of providing a continuous pumping operation at the designed rates and control slurry density. Backup equipment should be available in order to address possible pumping equipment failures while circulating the cement.

6.4.6 Cement Evaluation and Location

Evaluation of cement placement and quality is done to determine that a competent seal exists to prevent the communication of fluids from the storage zone or other zones of interest.

The location and quality of the cement bond or seal between the production casing, or liner if applicable, and formation shall be evaluated to determine whether adequate formation and pipe bonding has been achieved to prevent the migration of gas and fluids between zones.

NOTE 1 It is important that cement bonding is present across the caprock of the storage zone to maintain the mechanical integrity of the well and protect the storage reservoir.

Cement placement and bond quality shall be evaluated with a cement bond log or other means that can demonstrate the sealing potential of the cement. The evaluation should not take place until the cement cure time determined in the cement design has allowed the cement to reach a sufficient compressive strength for accurate interpretation of the log or method being used.

NOTE 2 API 10TR1 [14] provides principles and practices regarding the evaluation of primary cementation of casing strings in oil and gas wells.

NOTE 3 Radial cement bond logs help to identify cement channeling that can impair zonal isolation.

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NOTE 4 A temperature log run in the first 12 to 24 hours after cementing assists in locating the approximate top of the cement, but does not indicate the quality or bonding of the cement to the casing and borehole wall surfaces.

The operator should observe the well's annuli after cementing operations to determine that no annular flow or other evidence of containment issues exist.

A mechanical integrity test (see 6.9) of each casing string should be completed prior to drilling out or perforating.

6.5 Completion and Stimulation

6.5.1 General

The operator shall design and conduct well completion and stimulation operations to verify that pressure, flow rates, and other mechanical conditions have no adverse impact on the storage reservoir, caprock, or the mechanical integrity of the well.

The operator should review casing and wellhead design and installation parameters, workover history, and previous mechanical integrity tests to verify that stimulation and completion loads do not exceed the pressure limits and safety factors, which could result in a failure of the well's mechanical integrity.

6.5.2 Baseline Logging

The operator should run a cased-hole formation log to correlate with the baseline formation log prior to completion and/or stimulation treatments in order to verify the location of the production casing and casing collars relative to the formations traversed by the well.

6.5.3 Fracture Stimulation

When a fracture treatment is applied, it shall be conducted in a manner such that the fracture height or length does not compromise the integrity of the storage reservoir.

The operator should follow API fracturing guidance documents: API HF1 [15], API HF2 [16], and API HF3 [17].

The operator should monitor wells and the reservoir after fracture treatment of a well at an increased frequency for abnormal conditions that could indicate a loss of integrity. 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 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.

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6.6 Well Remediation

6.6.1 General

A well identified as having compromised mechanical integrity shall be evaluated and responsive action implemented within a timeframe and by method(s) determined by the operator and corresponding to the severity of the integrity risk.

NOTE Section 8 assists the operator in characterizing risk and building integrity plans to address integrity monitoring and treatment.

6.6.2 Evaluation and Responsive Action

The operator should review logs, such as casing inspection logs or mechanical integrity tests, prior to planning and conducting well remediation activities.

The operator should assess the risk associated with working on a well at various reservoir pressures when planning remediation work.

If a well is to be kept out of active service for a length of time (as determined by the operator) before remediation occurs, but could otherwise act as a conduit for communication, the operator should continue to monitor the well.

Before placing a well back in service, the operator should reassess the well's integrity and address any newly identified integrity threats that may have developed during the remediation.

6.7 Well Closure (Plugging and Abandonment)

6.7.1 General

The operator shall design a well abandonment for long-term isolation of the storage zone in order to prevent fluid flow between the storage zone and any other penetrated zone and the surface.

NOTE See API E3 [18] for guidance on well abandonment practices and procedures.

6.7.2 Storage Zone Isolation

The operator shall use cement plugs (see 6.4.3) and/or mechanical plugs to isolate the storage zone from fluid migration. The use of hydrostatic pressure as a sole means of isolation shall not be acceptable.

Cement should meet quality standards in API 10A and ASTM C150/C150M or exceed the requirements set in these standards.

The operator should assess the long-term viability of the plug design to achieve and maintain the required isolation.

NOTE 1 The U.S. Bureau of Safety and Environmental Enforcement, Report RLS0116 [19] contains observations on cement plug viability.

A cement plug should be of a length that, whether by itself or in combination with a mechanical plug, achieves isolation of the storage zone.

NOTE 2 Several U.S. state regulatory agencies require a minimum cement plug length of 100 ft.

The well should be in a static condition prior to setting of a cement plug and during the curing process.

Volume-extending additives should not be used in cement plugs.

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The operator shall determine the location of groundwater and hydrocarbon bearing zones (in addition to the storage zone) penetrated by the well to be abandoned, and the condition of the well's casing and cement across those zones, to prevent communication between any of those zones during and after plugging of the well. Special provisions may be necessary to isolate formations behind uncemented casing.

The operator should evaluate the condition of the well to be abandoned for any issue that would limit access to the wellbore or hinder placing plugs across the storage zone and other critical zones in order to establish conditions for long-term plug sealing reliability across and against the storage zone.

The operator shall verify that the casing-borehole cement seals the storage interval in the well being abandoned in order to achieve annular isolation and prevent communication.

The operator shall verify the presence and location of a cement plug after the plug is set and has reached a sufficient compressive strength; the operator shall correct deviations which may threaten isolation objectives of the plug.

6.7.3 Abandoned Well Maintenance

The operator shall repair a failed plug; the operator shall repair a well with any leak indication that may suggest a lack of isolation of the storage reservoir.

In order to maintain the physical and site security of the abandoned well, the operator shall install a surface plug and cap. To make identification easier, the cap shall include the API number or other form of identification.

6.8 Environmental, Safety, and Health

6.8.1 Design and Construction Safeguards

Safeguards to the environment, safety, and health of workers and the public shall be incorporated into well design and well work activities.

NOTE Publications such as API 49 [20], API 51R, API 54 [21], and API 76 can be referenced to identify safeguards for application in storage well design and well work activities.

The operator shall take actions to protect surface water and groundwater resources in the design, drilling, and servicing of a well. The operator should conduct an environmental impact review prior to well drilling.

The operator shall monitor worksite conditions during well construction and well work activities in order to protect the environment and the safety and health of workers and the public.

6.8.2 Operation and Maintenance Safeguards

The operator should account for the long-term viability and functional integrity of the well in the well design and well work activities in order to promote the ability to maintain and operate the well consistent with environment regulations and to maintain worker and public safety throughout the life of the well.

The operator shall have an emergency response plan as described in Section 10.

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6.9 Testing and Commissioning

6.9.1 Testing Methods

A new well, or a well that has had its existing production casing modified from its previous condition during workover activities, shall be tested to demonstrate mechanical integrity and suitability for the designed operating conditions prior to commissioning by one of the following tests.

a) For new well construction, the production casing shall be tested prior to drilling out the shoe, taking into account the cement design factors so that this test does not compromise the cement integrity.

b) For existing production casing, the production casing shall be tested after setting a retrievable plug as close as practical to the top of the storage formation.

NOTE A commonly used test parameter is an initial test pressure of 1.1 times the maximum allowable operating pressure, with test duration of at least 30 minutes and a pressure drop not exceeding 10% of the initial test pressure. Applicable regulations may stipulate other parameters.

c) For a well completed with tubing and packer, the tubing-casing annulus shall be tested.

The operator shall design a test so the maximum pressure on the packer seat and the pressure at any point in the wellbore during the test does not compromise the mechanical integrity of the well.

6.9.2 Casing Inspection Logging

The operator should perform baseline casing inspection logging on new production casing. If an existing well is converted to be a storage well, the operator should perform a baseline casing inspection log on the production casing of the converted well.

6.10 Monitoring of Construction Activities

6.10.1 General

Gas storage development and replacement activities should be monitored and evaluated in a manner that verifies mechanical integrity in the design and construction of wells.

6.10.2 Procedures and Documentation

The operator should monitor and verify that construction procedures, as required in 11.2, are followed and documentation for project design, material and equipment acquisition, well construction, and commissioning are maintained, as described in 6.11.

6.10.3 Work Supervision

Well drilling, servicing, testing, and commissioning activities should be supervised at the job site by personnel who are aware of, trained in, and experienced in the company procedures, regulatory and safety requirements, and geological and engineering aspects related to the work being performed.

The operator should document that on-site supervisory personnel have the knowledge, skills, and abilities for the work to be performed under their supervision.

The operator should document that contractor equipment is suitable and personnel are capable for the work being performed and aware of the operator's procedures related to such work. Requirements related to contractor personnel are covered in 11.12.

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6.10.4 Resolution of Issues

The operator should monitor and address issues or problems encountered during drilling, completion, and stimulation of a well. If the resolution of encountered issues or problems causes the operator to deviate from the original design or to alter the procedures for a well, the operator shall document the changes and keep the document in the well records.

The operator shall resolve issues or problems in a manner that maintains functional integrity of the well and storage reservoir prior to commissioning the well for service.

The operator should determine if the resolutions to identified issues need to be incorporated into the design of future wells and treatments.

The operator should review the geologic or engineering data collected during well construction or remediation to determine if that information could impact or require changes in the reservoir characterization as outlined in 5.2 and 5.3.

6.11 Recordkeeping

6.11.1 Well Work Records

Records of well completion (as-built), well construction and well work activities shall be maintained for the life of the facility. These records shall include, as applicable and available, the items listed below as referenced in each subsection.

- *6.2 Wellhead Equipment and Valves*
  - Material and test records.
  - Design evaluations.
  - Emergency shutdown valve evaluation.
  - Inspection and repair records.
- *6.3 Well Casing*
  - Material and test records.
  - Design evaluations.
  - Setting depths of all strings of casing.
  - Connection design evaluation.
  - Connection torque verification.
- *6.4 Casing Cementing Practices*
  - Blends, additives, and volumes pumped.
  - Volume of cement circulated to surface.
  - pH of mix water and water temperature.
  - Pump and displacement rates and displacement times.

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- Preflush type and volume pumped.
- Type of float and centralization equipment and location in string.
- Theoretical and actual displacement volumes.
- Detail of remedial cementing work performed.
- Cement service company's field report and log of job.
- Logged cement placement and any evaluation of quality of seal.

— *6.5 Completion and Stimulation Considerations*

- Service company field reports and job logs.
- Location and description of stimulation treatments.
- Composition and volumes of any fluid used.
- Cementing reports (as detailed in 6.4).
- Type of equipment used and location in well.
- Cased hole correlation logs.
- Post-treatment monitoring data and analysis.

— *6.6 Well Remediation*

- Cementing reports (as detailed in 6.4).
- Type of equipment used and location in well.
- Well logs.
- Workover and recompletion reports.

— *6.7 Well Closure*

- Equipment removed from well.
- Cementing reports (as detailed in 6.4).
- Plugging records filed with local regulatory authorities.

— *6.9 Testing and Commissioning*

- Mechanical integrity test data.
- Pressure test data.
- Type and amount of fluid in annulus of tubing and packer completion.
- Casing inspection logs.

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— *6.10 Monitoring of Construction Activities*

  — Received equipment and material specifications.

  — Changes in well construction from original well design.

  — Rig and service company field tickets and job logs.

  — Daily drilling and servicing reports, geolograph records, and driller's log.

  — Mud records.

  — Wireline logs and mud logs.

NOTE Those records that relate to the current state of completion and functional integrity are most relevant.

6.11.2 Permitting, Procedures, Personnel, and Equipment Records

Records relating to permitting, procedures, personnel, and equipment shall be retained for a period that meets regulatory requirements, or where no regulatory requirements exist, intervals as determined by the operator. These records shall include, as applicable and available, the items listed below as referenced in each subsection.

— *6.8 Environmental, Health, and Safety*

  — On-site safety meeting records.

— *6.10 Monitoring of Construction Activities*

  — Supervisor qualifications.

  — Contractor personnel qualifications.

  — Equipment suitability records.

  — Contractor safety orientation.

7 Functional Integrity of the Natural Gas Storage Reservoir and Wells Established and Demonstrated Through Initial Attainment of Maximum Reservoir Pressure and Total Inventory

7.1 General

This section addresses the requirements for verifying functional integrity of the natural gas storage reservoir and wells during reservoir development and during commissioning until reaching the designed maximum reservoir pressure and/or total capacity. Section 9 addresses integrity demonstration, verification, and monitoring for existing storage reservoirs on an ongoing basis.

7.2 Testing and Commissioning

7.2.1 General

Facility integrity and baseline performance conditions should be established and documented in order to allow identification of anomalous conditions during commissioning and operation.

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7.2.2 Integrity Assurance

Mechanical integrity tests and/or mechanical condition evaluation shall be performed prior to project commissioning in order to verify that each well is capable of meeting the designed operating conditions. Requirements related to well mechanical integrity testing are covered in 6.9.

Wells identified for plugging or replugging should be scheduled for such work on a priority basis in accordance with the facility construction schedule and facility integrity plan (as described in 5.4.7), and in consultation with regulatory authorities, as applicable. Requirements related to well closure are covered in 6.7.

7.2.3 Baseline Conditions

Baseline pressure and volume conditions of the reservoir should be established and documented prior to commissioning, as discussed in 5.3.

Observation well baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition, and liquid level should be documented prior to commissioning.

Baseline quality of groundwater in the vicinity of the storage operation may be tested prior to commissioning or as specified by regulatory authorities.

7.3 Reservoir Integrity Monitoring

7.3.1 General

The material balance behavior of a storage reservoir shall be monitored relative to the original design and expected reservoir behavior established prior to commissioning and start-up. Unexpected conditions detected during monitoring shall be evaluated and corrected in order to avoid an incident or loss. Monitoring frequency should be based on factors such as reservoir and well fluid loss potential and flow potential.

7.3.2 Monitoring and Analysis Methods

Average reservoir pressure versus inventory shall be monitored and compared to expected conditions in order to allow for the discovery and correction of any unexpected conditions. Typically, a shut-in key indicator well(s) or an observation well(s) that represents the average shut-in reservoir pressure provides the most useful pressure-inventory relationship. In lieu of shut-in observation wells, the relationship may be based on a flowing well pressure. Liquid level should be taken into account when using observation wells. Semiannual field shut-in tests, usually occurring at the point of seasonally high and low inventories, should be conducted for inventory verification.

Strategically located observation wells in the vicinity of spill points, within an aquifer, and above the caprock in potential collector formations should be installed and monitored to detect the presence or movement of gas using methods which can include review of fluid level records, well pressures, geophysical logging, gas composition, or other tools and methods.

Offset hydrocarbon production or disposal operations should be monitored for unexplained flow or pressure changes. The monitoring should include operations in zones above and below the storage reservoir as well as laterally offset locations.

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.

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7.4 Mechanical Integrity Monitoring

7.4.1 General

Wells and related facilities shall be monitored in order to allow for the discovery and correction of abnormal operating conditions.

7.4.2 Surface Monitoring Methods

Wellheads, well safety systems, well piping, and site locations should be inspected for operability, leaks, and mechanical or other faults.

Wellhead injection pressure and injection flow rate should be monitored for unexpected changes indicative of a mechanical fault.

Observation well pressures or fluid levels should be monitored for unexpected changes indicative of mechanical fault.

Well annulus pressures or vents should be monitored.

Plugged well site locations should be inspected for evidence of leakage or surface encroachments.

7.4.3 Subsurface Monitoring Methods

Subsurface pressure or temperature surveys to locate suspected flow anomalies may be performed, as needed. More sophisticated production logging tools such as spinner surveys or noise logs may be used to augment the investigation.

Subsurface mechanical condition surveys such as cement bond logs and casing inspection logs to identify suspected mechanical integrity issues may be conducted as needed.

Subsurface correlation and gas identification logs such as gamma ray and neutron log suite to locate suspected anomalous gas accumulations above or below the intended reservoir may be obtained as needed.

7.5 Recordkeeping

Records of natural gas storage testing and monitoring activities covered under this section shall be maintained for the life of the facility. The records shall include, as applicable and available:

a) reservoir and well mechanical integrity records that demonstrate functional integrity during commissioning, including monitoring data and analyses;

b) well testing records and records of well actions taken during commissioning; and

c) regulatory records for project commissioning including permit applications, permits, and all reports and correspondence with regulatory agencies.

8 Risk Management for Gas Storage Operations

8.1 General

This section addresses risk management for surface and subsurface facilities including the wells and reservoir but excludes pipelines and compressor stations. Risk is defined as the consequence of a realized threat multiplied by the likelihood of its occurrence.

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NOTE Bibliography Items [22] to [27] provide further references that various industries, including pipeline and storage operators, employ in the application of risk or asset management.

8.2 Risk Management

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 preventive, 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.

8.3 Data Collection and Integration

8.3.1 General

Identifying and collecting the information relevant to a storage field is part of risk management. Data review and integration can highlight conditions in need of attention or additional information collection, assist in threat and hazard identification and risk analysis, and contribute to the continual improvement process.

8.3.2 Data Sources

The operator shall use available information such as performance data collected through the field history, operations and maintenance (O&M) activities, geotechnical data such as well logs, engineering data, and completion reports to determine susceptibility to threat and hazard-related events and to assess threat and hazard interaction.

8.4 Threat and Hazard Identification and Analysis

8.4.1 General

A hazard is a situation or condition that has the potential to cause loss, damage, or harm to a storage well, well site, or reservoir and thus affect the functional integrity of the storage operation. A threat to storage functional integrity can be created by an encounter with or an activation of a hazard in the course of the storage operation. 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 threat. A lack of data or information should not be used as justification to exclude a specific threat.

8.4.2 Methodology

The operator shall evaluate the potential threats and hazards impacting storage wells and reservoirs. The operator should refer to the list of common threats and hazards in Table 1 and may supplement the list in Table 1 with other hazards or threats identified by site-specific assessments.

The operator should estimate risk from potential events that could occur related to potential threats and hazards to individual facilities, such as wells, and by region when considering the reservoir.

The operator should assess potential threat and/or hazard interaction, such as the relationship of the threat of casing damage during well drilling or service work that could exacerbate corrosion processes.

The operator should perform periodic evaluations of hazards, threats, and risks related to potential events in order to account for changes in perception of likelihood or consequence in event potential.

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Table 1—Potential Threats and Consequences

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Wells	Well integrity (corrosion, material defects, erosion, equipment failure, annular flow)	Gas containment failure due to inadequately sealed storage well(s), e.g. casing corrosion, cement bond failure, material defect, valve failure, gasket failure, thread leaks, etc.	— Loss of stored gas inventory — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources and/or wells — Decrease or loss of field performance
	Design	Gas containment failure due to inadequately completed wells, sealed plugged well(s), failure of cement squeeze job perforations or stage tool, pressure rating of components, etc.	— Release of gas to the atmosphere — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources and/or wells — Loss of stored gas inventory — Decrease or loss of field performance
	Operation and maintenance activities	— Inadequate procedures — Failure to follow procedures — Inadequate training — Inexperienced personnel and/or supervision	— Loss of stored gas inventory — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources and/or wells — Decrease or loss of field performance
	Well intervention	Gas containment failure due to loss of control of a storage well while drilling, reconditioning, stimulation, logging, working on downhole safety valves, etc.	— Damage to drilling rig or service rig — Loss of tools in wellbore — Hazard to operator and service company personnel on well site — Safety hazard to public — Decrease or loss of field performance — Loss of well
	Third-party damage (intentional/unintentional damage)	Intentional/unintentional damage	— Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities: — loss of ancillary facilities — well on/off status change — impact to service reliability — impact to neighboring public, storage gas loss
	Outside force—natural causes	Weather related and ground movement	— Heavy rains, floods, lightning, earth movements, groundwater table changes, subsidence, etc. that could result in: — damage to facilities/impact to service reliability

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Table 1—Potential Threats and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Reservoir	Third-party damage (third-party well operations)	Third-party drilling, completion, and workover activities	— Drilling into, through, or adjacent to the storage reservoir could result in loss of containment — Production well stimulation damages to storage well — Poor cement bond that could result in inability to meet design performance requirements — Loss of stored gas inventory — Damage to third-party/public property and personnel
		Third-party production, injection, or disposal operations	— Decrease in field performance (both working gas cycling and deliverability) — Loss of stored gas inventory — Safety hazard if pressure rating of production facilities are not as high as storage pressure — Inability to meet design performance requirements — Damage to third-party/public property and personnel
	Geologic uncertainty	Uncertainty of extent of reservoir boundary	— Gas migration beyond control of storage wells — Behavior of field under storage operations different than under production that could result in storage gas loss — Inability to meet design performance requirements — Damage to third-party/public property and personnel
		Expansion, contraction, and migration of storage gas	— Expansion, contraction, and migration due to operations that could result in inability to meet design performance requirements and loss of stored gas inventory
		Failure of caprock	— Vertical gas migration, likely during testing phase, initial activation, or when initial pressure is exceeded that could result in gas migration into shallower zones including water sources — Loss of stored gas inventory — For existing field a potential abandonment or requirement of re-cycling facilities
	Reservoir fluid compatibility issues	Contamination of storage reservoir by foreign fluids	— Wellbore damage caused by drilling and completion fluids, water/chemical floods, H_2S generating bacteria, stored gas quality, etc. — Internal corrosion that could result in a degradation to field performance (both working gas cycling and deliverability) and well and/or pipeline repairs/failures

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Table 1—Potential Threats and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Surface	Third-party damage (surface encroachment)	Surface encroachments	— Buildings/roadways/structures construction, cathodic protection current from pipelines, power line current and overhead wires, expansion of park lands, mining, flood control dams, etc. that could result in: — inability to access, operate or maintain facilities — facility abandonment — reduced ability to site additional wells and facilities due to setback restrictions
	Third-party damage (intentional/ unintentional damage)	Intentional/unintentional damage	— Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities: — loss of ancillary facilities — well on/off status change — impact to service reliability — impact to neighboring public, storage gas loss
	Outside force—natural causes	Weather related and ground movement	— Heavy rains, floods, lightning, earth movements, groundwater table changes, subsidence, etc. that could result in: — damage to facilities/impact to service reliability

8.5 Risk Assessment

8.5.1 General

Risk assessment uses tools and techniques that evaluate and prioritize risks to direct risk management activities toward promoting functional integrity of the storage operation.

8.5.2 Methodology

The operator shall assess risk related to the storage operation using a consistent process.

The operator should determine the risk assessment method applicable for the facilities. A risk assessment method should include the following characteristics in the risk assessment protocol:

a) identification of potential threats and hazards to a storage facility;

b) evaluation of likelihood of events and consequences related to the events;

c) determination of risk ranking to develop preventive and mitigating measures to monitor and/or reduce risk;

d) documentation of risk evaluation and decision basis for preventive and mitigative (P&M) measures;

e) provision for data feedback and validation; and

f) regular, periodic risk assessment reviews to update information and evaluate risk management effectiveness.

The operator shall review the results of the risk assessment to determine whether the risk assessment, resulting prioritization, or ranking represents its facilities and characterizes the risks. Review may be performed by personnel familiar with storage operations, risk management, and methods of analyzing risk and results.

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8.6 Preventive and Mitigative Measures

8.6.1 General

P&M measures are actions conducted by the operator to reduce the risks to the storage facilities by reducing the likelihood (preventive) or reducing the consequence (mitigative) of events related to the threats identified in 8.4. The P&M measures include routine condition monitoring activities since the acquisition and analysis of data provides information upon which additional measures can be implemented. Table 2 presents a list of programs, methods, or tools commonly employed by operators to monitor and manage risks. The table further provides a reference of those sections in this RP that address risks identified by the operator.

Table 2—Preventive and Mitigative Programs

Category of Review	Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs	Reference Location(s) of Program in API 1171
Wells	Well integrity (corrosion, material defects, erosion, equipment failure, annular flow)	Casing condition and inspection program	9.3
		Monitoring pressure, rate and inventory	9.6
		Cement analysis and evaluation	5.3; 6.4
		Internal corrosion monitoring	9.3
		Plugged and abandoned well review and surveillance	5.3; 6.7; 9.3
		Monitor annular pressures, rates, or temperatures	9.3
		Subsurface and surface shut-off valves	9.3; 6.2
		Monitor cathodic protection as applicable.	9.3
		Operate, maintain, and inspect valves and other components	9.3
	Design	Collect and evaluate plugged and abandoned well records and rework or plug	5.3; 7.2; 6.7; 9.3
		Develop design standards for new wells	Section 6 (all except 6.5, 6.6, and 6.7)
		Evaluate current completion of existing wells for functional integrity and determine if remediation monitoring is required	5.3; 6.2, 6.3, 6.4; 9.2, 9.3
	Operations and maintenance activities	Procedures	11.2
		Training of personnel and contractors and establishment of procedures	11.12; 6.10
	Well intervention	Implement training and safety programs for company and contractor personnel	11.2; 10.6 (for emergency response training)
		Develop detailed drilling and well servicing procedures	11.5

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Table 2—Preventive and Mitigative Programs (Continued)

Category of Review	Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs	Reference Location(s) of Program in API 1171
Reservoir	Third-party damage (third-party well operations)	Bilateral agreements or statutory requirements for production wells to incorporate additional design features to isolate the storage horizon during drilling, completion, stimulation, and production. Examples include a separate string of cemented casing across the storage horizon and maintaining an adequate vertical and lateral buffer from the storage reservoir.	9.3, 9.4
		Agreements with third-party production operations to have access and observation during the drilling, completion, and production phases	9.3, 9.4
		Monitor drilling and mining permits and activity	9.4
		Promote development of rules and regulations for the protection of storage from third-party oil and gas development	11.10 (policy and public awareness)
		Surface and subsurface setback requirements from storage wells and well sites for both vertical and lateral buffer zone	9.3, 9.4
		Gas sampling analysis of storage wells and production wells and collection of production data to review for communication by storage operations	9.3, 9.4
		Acquire third-party production wells and mineral rights	5.2; 5.3; 9.4
		Pursue legal options (condemnation, enjoin production, etc.)	5.2, 5.3; 9.4
	Geologic uncertainty	Collect and review existing regional geological studies and data	5.2; 9.4
		Collect geological, geophysical, and reservoir data on existing wells in/adjacent to the storage field	5.2; 5.3; 9.4
		Acquire new data (e.g. electric logs, new wells, core, seismic, well testing, tracer gas studies, etc.)	5.4; 9.4
		Establish buffer zone, (vertical and horizontal) with governing agency and update as necessary	5.2; 5.3; 9.4.
		Conduct semiannual tests for inventory verification	9.5
		Acquire property and mineral rights	5.2; 5.3; 9.4
		Establish observation wells based on evaluation of need	5.4; 9.4
		Inspect plugged and abandoned wells, review records	9.3
	Reservoir fluid compatibility issues	Conduct fluid compatibility studies on samples of the reservoir rock and/or review of literature	5.3; 9.3
		Conduct internal corrosion studies and evaluate mitigation programs as needed	9.3
		Monitor composition and quality of gas	9.4, 9.5

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Table 2—Preventive and Mitigative Programs (Continued)

Category of Review	Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs	Reference Location(s) of Program in API 1171
Surface	Third-party damage (surface encroachment)	Ensure surface operating rights agreements (e.g. leases, easements, etc.) clearly specify storage operator's rights for ingress, egress, and mutual setback distances from wells/structures, etc.	9.3, 9.4; 10.3
		Work with landowners, local planning/zoning commissions, and others on the surface operating requirements around storage wells	11.10
		Use of existing public awareness activities required for pipelines	11.10
		Monitor use of the surface and subsurface around wells and enforce setback rights when encroachments threaten the well	9.2, 9.3; 10.3
	Third-party damage (intentional/unintentional damage)	Install protection equipment (e.g. fences, alarms, etc.) for site security and safety	6.2; 10.2
		Include storage facilities into the corporate security plans	10.2
		Develop storage well blowout contingency plan	10.6
		Liaison with local, state, and federal law enforcement agencies	10.6
		811 Call-Before-You-Dig programs (damage prevention program)	11.10
	Outside force—natural causes	Perform routine patrols and surveillance, and event-specific surveillance activities	10.5
		Develop design specifications (e.g. barriers to deflect flood debris) for areas prone to flooding, earth movements, river/stream bed movement, and other natural causes	10.2, 10.3
		Develop site-specific plans for known problems such as areas prone to flooding, earth movements, river/stream bed movement, and other natural causes	5.4; 9.2; 10.6
		Monitor areas prone to flooding, earth movements, river/stream bed movement, and other natural causes for impacts on nearby well sites	10.5, 10.6
		Plug and abandon a well and drill replacement in more stable location	6.7, 6.10
		Remote control capabilities	6.2

8.6.2 Methodology

The operator shall develop P&M measures to manage risks.

The operator should review the P&M measures listed in Table 2 to determine those measures that manage risks based on site-specific conditions. Not all risks need a P&M measure if the level of risk is fully acceptable or if it is not necessary to reduce risk by further efforts.

The operator should employ the effective P&M measures and train their personnel on the procedures related to the P&M measures (see Section 11). The operator can apply these P&M measures to individual wells, individual reservoirs or fields, and/or groups of wells or fields.

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8.7 Periodic Review and Reassessment

8.7.1 General

The operator shall assess the effectiveness of risk monitoring and risk management programs and maintain a continual review and improvement cycle in risk management activities to provide functional integrity of the storage operation. The interval of review and reassessment should be short enough to identify operational and monitoring trends and measure the effectiveness of P&M measures, but long enough that the data and information that can be brought into the analysis are meaningful.

8.7.2 Frequency

The operator shall define a review frequency for the risk assessment and perform a review and update of the risk assessment in accordance with the defined frequency.

8.7.3 New Threats and Hazards

If during the course of operations new threats or hazards are identified, or the impact of threats or hazards changes markedly, the operator shall assess the risk associated with new conditions and evaluate and prioritize risk management options in accordance with the risk assessment.

8.7.4 Procedures

The operator should develop procedures that define the data or information to be reviewed, and methods of data trending or normalization in the context of the risk assessment, by analyzing such factors as integrity performance and the number and types of issues that are occurring, as well as other conditions that might trigger an evaluation at a shorter frequency (e.g. new encroachments, third-party drilling).

8.7.5 Evaluation Team

The operator should use a multi-disciplinary team for the review and reassessments.

8.7.6 Performance Measures

The operator should determine specific performance measures to monitor and review in order to determine if risk management actions need revisions or additional P&M measures.

8.8 Recordkeeping

The operator shall develop a risk management records retention schedule and management plan. The operator should define the records retention period. Risk management documentation can include data used during the risk assessment, P&M measures employed, and the periodic evaluation of performance metrics.

9 Integrity Demonstration, Verification, and Monitoring Practices

9.1 General

This section provides a methodology and requirements for storage reservoir and well integrity demonstration, verification, and monitoring.

9.2 Overview

9.2.1 Integrity Maintenance

The operator shall maintain functional integrity of storage wells and reservoirs. Storage wells and reservoirs can have different characteristics resulting in unique requirements in approaching integrity demonstration, verification, and monitoring.

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NOTE Operating and maintenance practices, repair or replacement of defective wellhead, valve, casing, or wellbore components, and/or temporary mitigative actions such as reducing operating pressure are examples of methods used as necessary to maintain functional integrity.

9.2.2 Risk-based Evaluation

Risk assessments shall be used as a basis for developing the integrity demonstration, verification, and monitoring tasks and evaluating their frequency requirements (see Section 8). Following the risk assessment, the operator should develop and maintain a program and procedures to address storage reservoir and well integrity monitoring practices for each storage facility, multiple facilities, and/or system-wide. The operator's approach should address the need for reevaluation of risk-based conclusions and the monitoring task frequency.

9.3 Well Integrity Demonstration, Verification, and Monitoring

9.3.1 Well Integrity Evaluation

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 by storage operations.

Well integrity evaluation methods typically used by operators include but are not limited to review of design, completion, and well work records, wellhead and downhole inspection, well pressure monitoring and testing, and gas sampling.

The operator shall request well integrity evaluation data from third-party well owner/operators following the frequency established using conclusions from the risk assessment.

Active well mechanical integrity evaluations shall include initial and subsequent evaluations as determined using the risk assessment and the information derived from the initial evaluation.

9.3.2 Well Integrity Monitoring

The operator shall monitor for presence of annular gas by measuring and recording annular pressure and/or annular gas flow. The operator shall evaluate each annular gas occurrence that exceeds operator- or regulatory-defined threshold levels determined from well integrity evaluation and from risk assessment. The operator should test wellhead seals when annulus pressure is detected and where injectable packing and/or test ports are present.

The operator shall visually inspect each wellhead assembly at least annually for leaks. The operator shall test the operation of the master valve and wellhead pipeline isolation valve at least annually for proper function and ability to isolate the well. The valves shall be maintained, repaired, or replaced in accordance with the operator's valve maintenance program for isolation valves.

Surface and subsurface safety valve systems, where installed, shall be function-tested at least annually. The tests shall be conducted in accordance with manufacturer's recommendations and the operator's procedures.

A closed storage well safety valve system shall be manually reopened at the site of the valve after an inspection and not opened from a remote location.

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:

— evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;

— corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;

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— annular and packer fluid corrosion potential; and

— corrosion potential of current flows associated with cathodic protection systems.

The operator should obtain a baseline gas detection log on each new well for use in detecting changes in gas indications behind casing throughout the wellbore over the life of the well.

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. Frequency of inspection should include an initial inspection and subsequent inspections as determined using Section 8. The operator should review plugging records to augment the plugged well site inspections.

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.

The operator should monitor active and plugged well sites for encroachment activities that may impact well integrity.

The operator should monitor shut-in well pressure trends for indications of well integrity or loss thereof.

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.

9.4 Reservoir Integrity

9.4.1 Geological Characterization

The operator should review and update reservoir geological characterizations and mapping as new data become available or if there is evidence of changes in the location of gas or in the level of pressure in the reservoir to identify the limits of the gas and any spill points (see 5.2 for additional information on geological reservoir characterization).

9.4.2 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.

9.4.3 Third-party Activity

The operator should monitor for third-party activity that could compromise the integrity of the storage reservoir. Such activities can include drilling, completion, plugging and abandonment, production, mining, or other site-specific activities. The operator should determine P&M measures and contact the third-party or regulatory agencies to foster implementation of those P&M measures.

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 party should be plugged in a manner to isolate the storage reservoir and protect its integrity.

NOTE A written agreement stating the storage operator's requirements for protecting the storage reservoir is sometimes negotiated with third parties actively drilling or producing within the reservoir area and buffer zone.

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9.4.4 Observation Wells

The operator should use observation wells around, above, or below the reservoir to monitor pathways of potential communication and/or migration.

NOTE Aquifer storage reservoirs use observation wells to monitor potential gas migration at locations such as reservoir spill points and potential collection points in porous formations above the caprock.

9.4.5 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.

9.5 Gas Inventory Assessment

9.5.1 Total Inventory

The operator should include in the total inventory for the reservoir the estimated remaining native gas at time of conversion, the injected base gas, and the working gas on the date of the test when performing inventory verification analyses.

9.5.2 Data Quality

The operator should investigate, document, and take steps to mitigate sources of uncertainty in data collected for inventory assessment purposes and the analysis of that data, including but not limited to calculations, gas measurement procedures, and shut-in pressure stabilization time.

9.5.3 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 (Section 8, Table 2) 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; and

— using key indicator wells to monitor the pressure relative to inventory.

9.5.4 Aquifer Reservoir Methodology

For an aquifer storage reservoir and/or converted depleted hydrocarbon reservoir with a strong water drive, the operator should use inventory assessment methods based on reservoir operating characteristics, including but not limited to:

— using key wells to monitor the pressure relative to inventory;

— calculating pound-days operated above and below aquifer pressure;

— monitoring fluid levels and pressures in observation wells above and surrounding the field; and,

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— performing gas pore volume calculations.

NOTE Aquifer storage reservoirs operate at pressures above and below aquifer pressure, resulting in water efflux and influx, and changing gas reservoir size. Therefore, semiannual surveys are often not effective in inventory assessment. In addition, extended shut-in periods, whether at high or low inventory levels, result in changes in the reservoir volume that could be detrimental to the reservoir's operation.

9.5.5 Additional Actions

The operator should account for measured and unmeasured storage gas inventory changes such as injections, withdrawals, fuel, operations, losses, or other uses.

The operator should calibrate pressure gauges and document the calibrations according to operator's procedures.

The operator should account for wellbore liquid levels, where wellbore liquid levels are suspected to be present, when analyzing wellhead and/or bottomhole pressure data for reservoir integrity with necessary corrections made for elevation and fluid gradients.

The operator should create and regularly update a pressure-inventory relationship for comparison to the design relationship as a means of monitoring reservoir integrity.

NOTE The pressures used in the analysis can be from key indicator wells, shut-in of key active wells, and/or periodic pressure surveys of the entire field.

The operator should monitor the injected and withdrawn gas composition as needed to allow updates to the characterization of the gas in place.

9.6 Flow and Pressure Monitoring

9.6.1 General

The operator should monitor the injection and withdrawal flow rates and pressures at each storage reservoir to assist in evaluating facility integrity.

NOTE Injection and/or withdrawal rates and corresponding field pipeline pressure variations from expected levels are useful to alert the operator of potential reservoir and/or well integrity issues.

9.6.2 Deviations

Well pressure and/or flows should be monitored for deviations from expectations to alert operators of potential wellbore integrity issues. A risk assessment can be used to determine the frequency and type of monitoring required.

9.6.3 Flow Erosion

The operator should monitor and assess flow conditions and limit the potential for erosion due to flow velocity. The operator should be aware of differences in erosion potential of flow velocity for dry gas flow and for wet or particle-laden flow. 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.

9.7 Integrity Nonconformance and Response

The operator should implement and maintain a program that provides a method of addressing and documenting nonconformance with regard to design criteria for well and reservoir integrity. Abnormal operating conditions encountered or anomalies discovered and actions taken to address each occurrence should be documented.

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9.8 Recordkeeping

9.8.1 Documentation

Inspections, tests, patrols, or analyses shall be documented according to the operator's procedures.

9.8.2 Retention

The operator shall maintain records of storage inventory assessments for the life of the facility.

10 Site Security and Safety, Site Inspections, and Emergency Preparedness and Response

10.1 General

This section addresses requirements for assessment and monitoring of site security and emergency preparedness to ensure the protection of operating personnel, the public, and underground natural gas storage facilities. It is the intent of this section to enable operating personnel to recognize and respond to abnormal operating conditions to protect life and property. These requirements are site specific and vary based on local conditions such as population density, terrain, land use, and environment of areas adjacent to the facility.

10.2 Site Security and Safety

10.2.1 General

In order to maintain site security and safety, the operator should maintain a process to limit access to storage wells during drilling, workover, operation, and abandonment activities; this requirement may be addressed through the use of a site access control plan. Security measures should be suited to the well flow potential, location, population density, natural forces, vandalism, terrain, and environment of areas adjacent to the facility.

10.2.2 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.

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The operator may employ additional measures to enhance site security and safety based on an analysis of site-specific factors. The operator may develop site-specific security and safety procedures for employees, contractors, and authorized visitors and establish and maintain training on the site-specific procedures.

10.2.3 Flammables

Sources of ignition and flammable-type equipment and materials should be located in a manner to provide for the ongoing safety at the wellhead or well site. The operator should evaluate the site-specific conditions of potential flow rates, pressures, and weather conditions when determining a safe distance from the wellhead for each source of ignition and flammable-type equipment and materials.

10.3 Ingress and Egress

10.3.1 Roads

Lease or well roads should be maintained in a condition that permits personnel and equipment access to the well.

10.3.2 Fences and Enclosures

Ingress or egress of the site may be controlled by fences or enclosures. When used at well locations, fences or enclosures shall comply with applicable fire codes and regulations.

10.4 Signage

10.4.1 Minimum Signage Information

Permanent weatherproof signage shall be installed at each well site for identification purposes. Signage should contain the following information, at a minimum:

— storage facility name, well name, and/or identification number;

— operator name; and,

— operator's 24-hour emergency contact number.

10.4.2 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.

10.5 Site Inspections

10.5.1 General

Site inspections for review of safety and security assurance should be performed to verify that requirements of this section are met and maintained.

NOTE Site inspections for safety and security can coincide with site inspection to check the well area for mechanical integrity purposes as detailed in 9.3.

10.5.2 Procedures

The operator should develop and implement procedures to ensure an effective inspection. Procedures should include:

— purpose of the inspection;

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— identity of the trained person conducting the inspection;

— frequency of inspection;

— items to be inspected in the form of a list that can be checked off as completed and become part of the inspection record;

— reassessment of hazards and potential threats; and,

— documentation, reporting, and recordkeeping requirements.

10.5.3 Risk Mitigation

The operator should plan and implement site security risk mitigation steps as appropriate.

10.6 Emergency Preparedness/Emergency Response

10.6.1 Emergency Preparedness/Emergency Response Plan

For site security and safety, the operator shall develop and implement a structured emergency preparedness/response plan in order to address accidental releases, equipment failures, natural disasters, and third-party emergencies. The operator should integrate natural gas storage emergency procedures with regulatory required procedures covering pipeline facilities where possible rather than creating storage-specific documents. The plan should include:

— company name;

— facility name;

— facility location (or 9-1-1 address, if available);

— personnel roles and responsibilities;

— internal and external communication protocol;

— emergency contact information including area codes;

— procedures for notification;

— procedures for response to leaks, fires, medical emergencies, explosions, and natural emergencies;

— procedures for response to release of hazardous materials;

— hazardous materials inventory; and,

— special considerations for accidental hydrocarbon release and well blowout.

NOTE Civil responders use the Incident Command System.

10.6.2 Training

Storage operations and applicable staff shall receive training in the use of the emergency preparedness/response plan. 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.

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10.6.3 Blowout Contingency Plan

The operator shall have a blowout contingency plan in place.

A blowout contingency plan is company specific and should identify the procedures, equipment, and personnel needed to avoid or respond to a loss of well control situation.

NOTE The operator can consult with well control experts in developing a blowout contingency plan.

10.7 Cyber Security

To the extent that transmitted well data or remote flow control activities are security issues, the operator may employ cyber security measures in order to provide site security and safety.

11 Procedures and Training

11.1 General

This section addresses requirements for the development, implementation, and maintenance of programs, plans, and procedures intended to safely and effectively guide the operator in design, construction, operation, and maintenance of underground natural gas storage facilities. Associated requirements are set forth regarding training of operator and contractor personnel to comply with established programs and procedures. Documentation and record retention to demonstrate compliance with or deviations from the programs, plans, and procedures are also addressed. The programs, plans, and procedures required in this section specifically cover gas storage wells and reservoirs; however, related pipeline and other regulated parts of the storage facility require the operator to have in place similar programs and procedures. Many publications and standards cover engineering requirements and recommended practices that impact the safe and reliable design, operation, and maintenance of underground natural gas storage reservoirs and related facilities. The operator is encouraged to review available resources including other API standards and ASME standards as well as other resources for possible guidance in development of their specific procedures.

11.2 Procedures

11.2.1 Construction, Operation, and Maintenance Procedures

The operator shall develop and follow procedures for the construction, operation, and maintenance of natural gas storage wells and reservoirs to establish and maintain functional integrity. When practicable, the operator's procedures should incorporate applicable industry recommended practices that promote personal and process safety, resource conservation, environmental stewardship, mechanical integrity, and reliable performance.

Procedures shall be in place prior to the development of a new storage facility. The procedures should address the 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.

Programs should integrate storage well and reservoir elements so that procedures and programs work together to promote the functional integrity of the storage facility.

The operator should integrate natural gas storage procedures with regulatory-required procedures covering pipeline facilities where possible rather than creating storage-specific documents. The operator might already have in place procedures for operation and maintenance, emergency response, integrity management, control room communications, qualification of personnel, management of change (MOC), and other procedures covering pipeline facilities. Specific operations related to natural gas storage wells and reservoirs requiring procedures include but are not limited to drilling, well workover, and reservoir integrity monitoring and management programs.

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A procedure should be written in clear language with enough detail to allow a person with appropriate training and experience to follow the procedure and achieve the desired objectives on a consistent basis.

Current procedures shall be available and readily accessible to operations, maintenance, and storage personnel. Procedures may be kept in paper or electronic format.

11.2.2 Review of Procedure Content

Procedures should be reviewed at a minimum frequency mandated by regulatory requirements, or if no requirements exist, as determined by the operator to ensure procedures are representative of current operations and technology. Procedures should be modified to account for changes in operating conditions, advancements in technology, regulatory changes, abnormal operating conditions, or as experience dictates. Procedure reviews should be documented and deficiencies or other changes noted in the review records. Implementation of changes should be documented as per 11.11.

11.2.3 Review of Procedure Adequacy

The operator should review the work being done by storage personnel to determine the adequacy and effectiveness of the procedures used in normal operation and maintenance of storage facilities. Reviews should be conducted periodically at a frequency determined in accordance with risk assessment practices recommended in Section 8. The operator should identify and document deficiencies, nonconformance, or deviations from established procedures and correct deficiencies or modify procedures as appropriate.

11.2.4 Record Retention

The operator should retain records necessary to properly administer the procedures and establish retention requirements for specific records.

11.3 Operations and Maintenance

11.3.1 General

The operator shall develop and implement O&M procedures covering storage wells and reservoirs prior to the commissioning operations set forth in Section 7.

11.3.2 Scope of Procedures

Procedures should outline and define routine inspection, testing, and monitoring activities (see Section 9), P&M measures for risk reduction (see 8.6), recognition of abnormal operating conditions, and the associated schedules and recordkeeping requirements. The procedures should address indications and/or circumstances identified during routine activities that may require supplemental activities or additional maintenance.

The operator should adapt and enhance general procedures when additional integrity monitoring activities are required to address special site-specific hazards or threats.

The operator should establish general procedures for well isolation necessary to perform maintenance functions, including options of venting, flaring, blow down, or other isolation procedures, as well as an assessment of the characteristics and volume of fluids in the context of safety and environmental protection.

The operator should develop procedures to identify abnormal operating conditions, respond to those conditions, and document those events. The procedures should require a periodic review of documented abnormal operating conditions for the purpose of establishing trends or lessons learned and modifying existing procedures to prevent recurrence.

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11.4 Emergency Plans

11.4.1 General

Emergency preparedness/response and blowout contingency plans referenced in 10.6 are required.

11.4.2 Plan Effectiveness

The operator shall establish a program to determine operator familiarity with emergency plans and procedures and periodic testing of the effectiveness of the plan in accordance with 10.6.

11.5 Well Work

11.5.1 General

The operator should establish a program to manage drilling, completion, servicing, and workover activities. This program should incorporate in a work plan the operator-established practices and procedures that are founded on industry recommended practices related to the drilling, completion, servicing, or workover operation to be performed. The work plan at a specific well should identify site-specific requirements, and the plan should account for hazards and conditions expected to be encountered in the well.

11.5.2 Scope of Procedures

The operator's established procedures should define minimum safety requirements for surface equipment, pressure control equipment, downhole operations, MOC processes, elements of process safety management, and other requirements as specified by regulations and the operator.

Drilling, completion, servicing, and workover plans should be reviewed with rig crews and other contractors as applicable prior to performing the work.

The operator's well-specific work plan should identify the pressure rating of blowout preventers and ancillary pressure control equipment. The pressure rating should be greater than the maximum anticipated surface pressure, and the plan should include requirements for verification and documentation that blowout preventers are in good working condition and have been tested after installation.

NOTE API 53 [28] and API 54 provide guidance related to blowout prevention equipment for drilling and well servicing operations.

The operator should require personnel whose duties include operation of well control equipment used in the drilling, completion, servicing, or workover operations to demonstrate knowledge, skill, and ability to operate the equipment (see 11.12).

The operator should require a person who is qualified in well control, or knowledgeable, skilled, and capable through experience to perform well control duties, to be on site at the well during active drilling, completion, servicing, and workover operations.

11.5.3 MOC During Drilling, Completion, and Servicing

The operator should define a MOC process to promote safety when unanticipated conditions are encountered in well drilling, completion, servicing, and workover operations. The process should include requirements for approval or authority for deviating from the procedures, making decisions, waiving existing procedures, and documentation of the change.

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11.6 Other Well Entry and Well Operation Procedures

11.6.1 General

The operator should establish a work plan when performing wireline, slickline, and logging operations, well testing, and other well operations requiring well entry. The plan should incorporate operator-established practices and procedures that are founded on industry recommended practices and applicable to the specific work to be performed. The work plan at a specific well should identify site-specific requirements and the plan should account for hazards and conditions expected to be encountered in the well.

11.6.2 Scope of Procedures

The operator should define operating conditions and activities where pressure control equipment is required.

The work plan should require that pressure control equipment be rated for the maximum anticipated surface pressure to be encountered during the operation.

The operator should verify that equipment used for pressure control is in good operating condition and suitable for the intended operation.

NOTE API 54 provides guidance related to pressure control equipment used in drilling and well servicing operations.

The operator should review the wellbore entry plan with the contractor prior to beginning the work.

The operator should confirm prior to wireline, slickline, and logging operations that the contractor is provided with:

a) well configuration and completion details;

b) characterization of the stored hydrocarbons and the presence of H_2S or other hazardous or corrosive agents;

c) anticipated wellbore and storage zone pressures and temperatures;

d) anticipated presence of water, fluids, deposits, or scale and restrictions in the wellbore;

e) safety requirements as outlined in 11.9; and,

f) reporting requirements.

11.7 Interaction with Control Room

11.7.1 General

Storage personnel shall be responsible for preparing and communicating guidelines for maintaining reservoir and well functional integrity.

11.7.2 Scope of Procedures

The operator should establish procedures for interaction and communication with a control room, including authority for initiating flow, operating, and shutting in natural gas storage facilities as required in order to maintain reservoir and well integrity during normal, abnormal, and emergency conditions.

11.8 Integrity and Risk Management

11.8.1 General

The operator should establish procedures to manage and maintain integrity of storage wells and reservoirs in accordance with the requirements of other sections of this standard.

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11.8.2 Scope of Procedures

The operator should develop procedures related to integrity and risk management that define the frequency or interval of review, data or information to be reviewed, and methods of data trending or normalization.

11.8.3 Review of Procedures

The operator should evaluate such factors as well and reservoir integrity performance and the number and types of issues that are occurring, as well as other issues, hazards, or threats that could require changing the frequency of future procedural reviews (e.g. new encroachments, third-party drilling).

11.9 Safety and Environmental Programs

11.9.1 General

The operator shall develop programs incorporating safeguards to the environment, site security, and safety and health into storage design, construction, and operations. The operator's programs should incorporate in a plan, or plans, operator-established procedures that are founded on industry recommended practices and applicable to process safety in storage operations.

11.9.2 Scope of Procedures

Plans and procedures addressing process safety can include:

— job plans;

— job reviews;

— job safety analyses;

— hazard analyses;

— risk mitigation;

— MOC; and,

— other procedures as deemed necessary by the operator.

The operator should verify that procedures address the conduct of work in a manner that minimizes environmental and safety risks.

11.10 Public Awareness and Damage Prevention

11.10.1 Scope

As required by regulations or as augmented by the operator, pipeline public awareness and damage prevention communications include information regarding the utilization of damage prevention notification systems, education of the public on the hazards related to unintended releases, indications of a release, procedures for reporting the release, and actions to be taken for public safety during the release.

11.10.2 Coordination of Programs

The storage operator should coordinate with existing pipeline public awareness and damage prevention plans where possible to address storage-specific communications that may include information such as well setback limits, encroachment and land use policies, or other information that could affect storage well or reservoir integrity.

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11.11 Management of Change

11.11.1 General

Revision of procedures and processes is an acceptable practice, but the operator shall require changes to be accomplished in a controlled manner. The program documentation, framework, and procedures shall be revised before the change can be implemented. Not all changes need be approved through a formal MOC process. Some changes are expected and may not be subject to a formal change control process. The operator should define the types of changes determined to be significant and requiring a MOC.

11.11.2 Scope

The operator should develop and maintain a MOC process that addresses changes in equipment, processes, materials, or procedures. The MOC process should include procedures to identify impacts associated with changes and determine the effect of the change on the storage facility. The MOC process should address approval authority and responsibility for the change and document implementation of the change.

A MOC procedure should include a process for approval of deviations from the procedures when necessitated by abnormal/emergency conditions.

The operator should update procedures, communicate and document changes to procedures in accordance with the operator's MOC process, and verify that personnel engaged in operating and maintaining the storage reservoir and wells are aware of and trained in those changes.

11.12 Training

11.12.1 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.

Training should address procedures specified in Section 11, safety procedures, recognition of abnormal operating conditions, and emergency conditions. Training programs may consist of various methodologies including but not limited to classroom, computer-based, and on-the-job training.

Training programs should be reviewed periodically to determine effectiveness.

The operator should modify training programs when changes occur in technology, processes, procedures, or facilities.

11.12.2 O&M Personnel

The operator should confirm by training and testing that persons assigned to operate and maintain storage wells and reservoirs possess the knowledge, skills, and abilities necessary to carry out their duties and responsibilities including those required for start-up, operation, and shutdown of storage facilities.

Personnel should be trained on the site-specific procedures necessary for operation of storage wells and reservoirs.

Personnel should be trained on the recognition of abnormal operating conditions.

Personnel should be trained on reporting requirements, documentation, and recordkeeping requirements.

Whenever changes are made to the operating procedures specified in 11.3, operating personnel shall be notified and trained as necessary in the changes and training documented before operating storage wells and reservoirs.

The operator should provide refresher training on a periodic basis to ensure that personnel understand and adhere to current operating procedures.

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11.12.3 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).

A supervisor should be qualified to provide competent and effective supervision of the operations being carried out.

A supervisor should confirm that personnel on site can recognize abnormal operating conditions and applicable hazards and know their role in safety and emergency procedures.

A supervisor should confirm that operating and contractor personnel conducting gas storage well and reservoir operations are qualified to perform the work.

A supervisor should verify that operating and contractor personnel understand and adhere to reporting requirements in the operator's procedures.

11.12.4 Contractor Personnel

The operator may 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.

The operator should provide and specify the scope of work to be performed by contractors.

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.

The operator should provide copies of the appropriate current procedures and review those procedures with contractors prior to any work being performed, and ensure that persons performing work in the storage field are familiar with the procedures and recordkeeping requirements.

The operator should provide training to contracted personnel that includes applicable site-specific safety procedures, awareness of rules pertaining to the facility, reporting requirements, and the applicable provisions of emergency action plans.

11.13 Records

11.13.1 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.

11.13.2 Training Records

The operator shall maintain records that demonstrate compliance with this subsection.

Company personnel training records should include:

— identification of the trained individual;

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— 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).

11.13.3 Retention

The operator shall establish retention intervals for records that meet regulatory requirements; where no regulatory requirements exist, retention intervals should be determined by the operator.

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INTEROFFICE CORRESPONDENCE

CALIFORNIA gas COMPANY

TO * See Below FROM R. D. Phillips DATE July 31, 1989

SUBJECT Project Approval Letters

* D. R. Horstman
M. E. Melton
S. P. Robinson

Attached are revised Project Approval Letters from the D.O.G. The D.O.G. modified their original approval letters as we requested at the annual review meetings in June. Specifically, the onerous requirements of calibrating test gauges has been greatly softened (see Stipulation #4 on the attached). The stipulation now states that pressures are measured and recorded weekly and that evidence of such measurement and calibration must be made available to them upon request. I interpret this to mean that we can continue taking and recording pressures has we now do and continue with our existing calibration procedures.

Stipulation #9 was also changed as we had requested. Graphs of oil, water and gas production rates vs. time are now required for the entire zone rather than for each well has originally required.

RDP:ds
Attachment

cc: N. D. Stevenson
R. W. Weibel

STATE OF CALIFORNIA-RESOURCES AGENCY
GEORGE DEUKMEJIAN, *Governor*

DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS
6401 TELEPHONE ROAD, SUITE 240
VENTURA, CALIFORNIA 93003-4458
(805) 654-4761

April 18, 1989
Revised July 26, 1989

R.W. Weibel, Agent
Southern California Gas. Co.
810 S. Flower St.
Los Angeles, CA. 90017

GAS STORAGE PROJECT
Aliso Canyo
Sesnon-Frew Zone

The Division of Oil and Gas has responsibility for wells that inject and withdraw natural gas from an underground storage facility. Our records indicate that, although individual wells have been permitted, project approval has not been issued by the Division to conduct underground gas storage operations in the Aliso Canyon field. Therefore, continued operation of the project is approved provided that:

1. Form OG105 or Form OG107 is used whenever a new well is to be drilled for use as an injection-withdrawal well, observation-collection well or whenever an existing well is to be converted to an injection-withdrawal well or observation-collection, even if no work is required. (Specific requirements will be outlined in our answer to your notice.)

2. When an existing well is to be converted to injection-withdrawal or observation-collection, a test is conducted to demonstrate the mechanical integrity of the casings.

3. A monthly injection-withdrawal report is furnished to this division listing the amount of gas injected, injection pressure, and amount of gas withdrawn from each well.

4. Surface pressures on each active or idle well are measured weekly with a calibrated test gauge, and recorded. Evidence of such measurement and calibration must be made available to this Division upon request.

5. All injection piping, valves and facilities meet or exceed design standards for the maximum anticipated injection pressure and are maintained in a safe and leak free condition.

6. The gas storage reservoir pressure shall not exceed 3600 psi. Tests may be required to establish that no damage will occur from excessive injection pressures.

7. A mechanical integrity test is made and filed with this Division for each injection-withdrawal well within three months after injection and/or withdrawal has commenced, at least once every year thereafter, after any significant anomalous rate or pressure change, or as requested by this office to confirm that the stored gas is confined to the intended zones.

8. A Division approved monitoring program plan is installed for the gas storage zone. Data shall be available for periodic inspection or as requested by the Division.

9. The following data are maintained for surveillance and evaluation of the project and are made available for periodic inspection by personnel from this Division:

   a. A graph of oil, water, and gas production rates vs. time for each zone.

   b. A graph of reservoir pressures, gas inventory fluctuations, and injection pressures.

   c. Observation well data, reservoir fluid distribution, temperature, radioactive tracer, and noise surveys.

10. Upon request, the Division is provided with any other data deemed necessary to monitor the operations of the project.

11. The Division is notified of any anticipated changes in a project resulting in alteration of conditions that were originally approved, such as: increase in size of the project, increase in the approved zone pressure; changes in the injection-withdrawal intervals; changes in the observation-collection intervals; or monitoring procedures. Such changes shall not be carried out without Division approval.

12. Any remedial work in the project area necessary because of the gas storage operation on idle, abandoned, or active wells needed to protect life, health, property and oil, gas, or freshwater zones will be the responsibility of the project operator.

13. Injection-withdrawal operations shall cease if any evidence of damage is observed or upon written notice from this Division.

Sincerely,

Patrick J. Kinnear

Patrick J. Kinnear
Deputy Supervisor

Ex. I - 6

Tubing and Packers in Underground Natural Gas Storage: Safety and Reliability Considerations

AGA/API/INGAA Underground Natural Gas Storage
Joint Industry Task Force

DRAFT

Shared by: Anders Johnson, Kinder Morgan & JITF
Nashville, Tennessee
September 16, 2016

SoCalGas-5.0097

Agenda

- Definitions
- Executive Summary
- JITF Tubing and Packer Considerations
- Conclusions
- Questions

Definitions

- BOP — Blowout preventer
- Collar — Internally threaded pipe used to join two pipes
- Gravel Pack — Gravel/screens at the bottom of the well that prevent sand from flowing up the well
- Packer — Expanding mechanical device that engages casing
- Slips — Mechanical jaws that engage the casing to prevent the packer from slipping
- Tubing — Screwed pipe joints, 30', coupled together to for a downhole tubing

Executive Summary

- Tubing and packer deployments are operationally beneficial in cases where the operator has designed the tubing/packer system to: isolate different production zones, increase gas velocity for liquid lift, convey a SSSV in high risk areas, and/or protect the surface casing from conditions such as scaling.
- Tubing/packer installations in existing wells can be problematic because: 1) the wellhead must be adapted to support the tubing, 2) once hung tubing prevents the casing in gas wells from being internally inspected without removing the tubing, 3) the tubing installation in an existing well may reduce flow by more than 60% and require the operator to drill additional wells to meet market peak delivery requirements.
- The benefits of tubing and packer in an existing well may be de minimis because of the increased risks and costs of installing and removing the tubing, considering that gas storage well failures in the U.S. are very unlikely[1] and that there are inspection techniques to improve the understanding of well integrity.
- Adding tubing to an existing well adds 51 – 267[2] potential leak points and decreases critical day deliverability. Tubing is not generally reused because of the increased leak potential from damaged threads during extraction thus adds cost without benefit.
- Regulations requiring frequent inspection of the casing increase the likelihood of a catastrophic incident due to the extraction and then re-installation of new tubing and packers each time the casing is inspected.
- Sound well design and a risk based well integrity program following API 1170/1171 guidelines should be applied to all tubing and packer installations.

[1]JIFT White paper July 2016

[2] 1500' well has 50 pipe joints, an 8000' well has ~267 pipe joints and one packer

Joint industry Task Force

- AGA-API-INGAA Joint Industry Task Force White Paper
- Represents 200,000 well-years of operating experience
- ~17,500 onshore gas storage wells
- ~13% of the existing gas storage well have tubing/packer completions
- Tubing packer failure rates reported from operators based on anecdotal experience are averaging less than 4e -4 well year failure rate over 20 years
- Re-entry and replacement rates for failed tubing and packer are less than 0.1 entries per well-year but comprise a real risk as the tubing may need to be pulled while the well is pressurized
- 100% of tubing and packer redress/replacement has been reported for every well re-entry containing tubing and packer by several of the major storage operators

Underground Natural Gas Storage JITF White Paper
http://www.energyinfrastructure.org/energy-101/natural-gas-storage

Concerns with Tubing and Packers in Existing Wells

Storage wells were not designed to accommodate tubing and packer in many cases, WH master valves cannot be closed if the tubing is hung above the master valve

Design and Construction

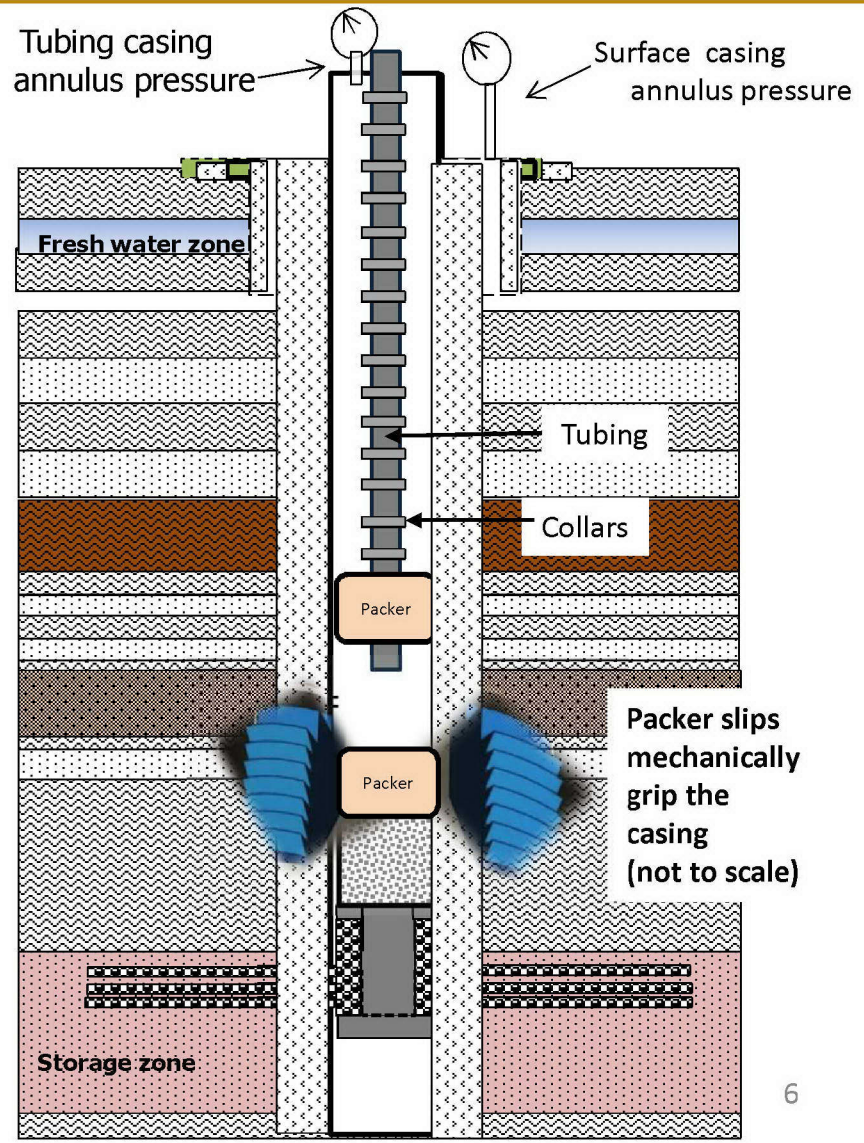
- Wellheads must be replaced and/or rebuilt to accommodate the dimensional changes of tubing hangers, wells will be out-of-service, and loss of delivery must be replaced.

Risk

- Greatest risk for an accident is during intervention
- Advanced tools such as High Resolution Vertilog cannot be used to analyze the condition of the casing when tubing is present
- Packer slips apply thousands of pounds of force into the casing and leave indications in the pipe wall
- Scale and ovality allow gas to leak around the packer
- Velocity induced erosion must be monitored

Deliverability

- Well flow on the peak day may be reduced >60% in some wells resulting in the inability to meet peak demand without drilling new wells which increase the number of leak points and future interventions



Limited Applications of Tubing and Packers in Existing Wells

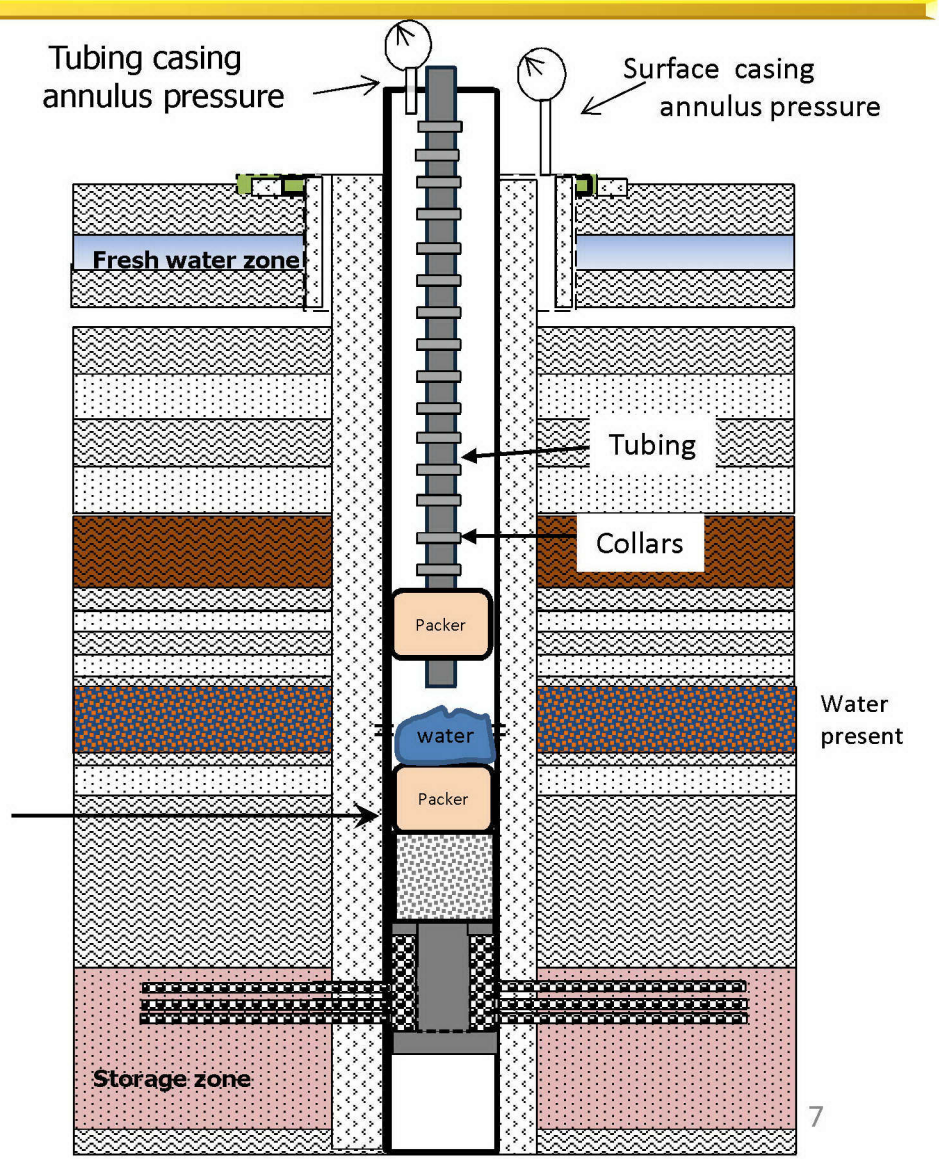
Underground Gas Storage wells were not designed to accommodate tubing and packer in many cases; however modifications are possible in larger diameter casings.

Design and Construction

- Wellheads must be replaced and/or rebuilt to accommodate dimensional changes of tubing hangers

Situational Operations Applications

- Preventing wells from watering off: Reduced flowing area in the tubing results in higher gas velocity enabling water and gas withdrawal as opposed to flow going to zero when the well fills with water
- Casing Concerns: Known casing anomalies can be ameliorated with tubing, reduction of casing pressure and monitoring of annulus pressures to detect issues
- Isolation requirements: Tubing and Packers can be used to isolate zones that are no longer required



Example of a Workover Rig

Installing /removing tubing from a well usually requires site preparation and workover rigs to handle thousands of pounds of steel. One of the greatest risks to people and the environment is the installation and removal of the tubing and the packer. Packers can seize in the well and require destructive milling to remove and re-establish the well bore

Tubing Flow Reduction = Loss of Delivery

Indicative flowing area restrictions resulting from installation of tubing into a production casing

Casing Diameter (inches)	Casing ID inches	Nominal Tubing Diameter	Flow Area Reduction
4-1/2”	3.5	2-3/8”	**54%**
5-1/2"	4.6	2-7/8”	**61%**
6 5/8"	5.7	3-1/5”	**62%**
8-5/8”	7.7	5-1/2”	**49%**
9-5/8”	8.4	7”	**31%**
13-3/8”	11.7	9-5/8”	**32%**

Flow is a function of temperature, cross-sectional area, and pressures Q f(t, a, P) in general a reduction in cross sectional area causes a pressure drop which reduces flow. Each field must be carefully examined, considering delivery requirements and critical day pressures. As the storage field pressures drop with declining inventory the flow impact of the reduced flowing area (tubing) becomes more detrimental. Some storage operators may see practical deliverability go to zero on critical flow days because of the restricted flow area and resulting pressure drop caused by the high gas velocities in the tubing.

Installing Tubing and Packers in Existing Gas Wells

Installing tubing and packer in an existing well

- Requires killing the well for 3–5 days, preparing the site for disturbance
- Trucking in workover rig, water, pumps, tanks , tubing, packer
- Removing wellhead and installing Blowout Preventer, BOP
- Re-building the wellhead, adding tubing hangers, re-welding piping connections that will be no longer aligned because of dimensional changes
- Cutting existing connecting piping and relocating shut-off valves
- Increased personnel on site for installation and extraction
- Increases well maintenance requirements and environmental exposure
- Decreases well deliverability, causes pressure drop and may require plugging and abandonment of marginal wells
- If excess field /well capacity is not available new wells must be drilled to meet peak day system needs driving up environmental exposure and risk

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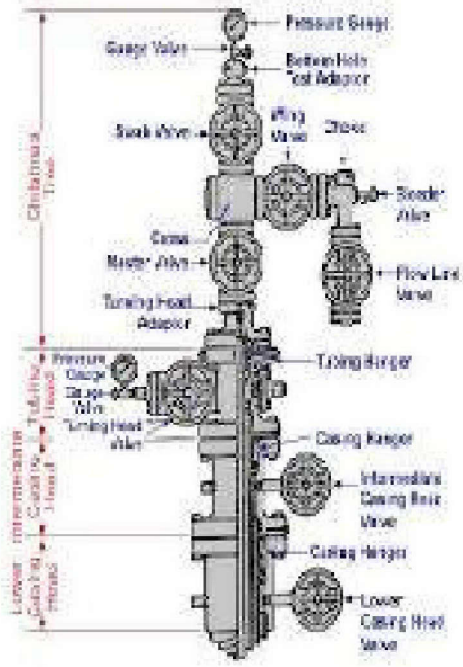
Cost of Down Hole Tubing

Adding tubing and packer to all competent wells adds Billions of $ of added capital cost with limited proven benefit and increases risk during installation and removal.

Nominal Tubing Diameter	Estimated Installed Cost
2-7/8”	$130,000*
5-1/2”	$215,000*
7”	$250,000*

*Estimates based on one set of conditions assuming nominal tubing sizes . Costs will vary, possibly more than +/-50% depending on site requirements



Source: m.blog.daum.net

Notes:
Approximately 15,000 storage wells do not have tubing and packers isolating the casing[1]
Tubing installation requires modifications to the existing wellhead and piping

AGA Underground storage survey[1]

Conclusions

- Proactive Well Integrity Programs are the best method of preventing unintended gas loss; multiple well barriers (casing/cement) mitigate risks. Tubing and packer are not needed in a well if the casing and cement were properly designed and installed
- Adding tubing adds a barrier within the well but also adds physical risks to people, increases environmental risk every time it is installed and removed, and reduced deliverability
- Tubing consists of screwed pipe joints and therefore adds potential leak points
- Tubing must be removed from the well to inspect the casing and increases the risk of a catastrophic incident while thousands of pounds of steel are pulled from a well under pressure
- Packers are mechanically expanded downhole and exert thousands of pounds of force on the casing. Packers may damage the casing and most operators do not set a packer in the same location because of the damage caused by the slips
- Regulations requiring frequent inspection of the casing increase the likelihood of a catastrophic incident associated with increase in well interventions to extract and then re-install new tubing and packers. (Tubing is not generally reused because of the increased leak potential from damaged threads during extraction).
- Conformance with API 1171 “shalls” provides a consistent and thought-out risk based approach that can be implemented over 7 – 10 years with the greatest risk situations being addressed within the first 5 years

Appendices

- Poll of U.S. Underground Natural Gas Storage Operators indicates that approximately **13%** of existing gas storage wells have tubing and packer installed within the well bore - September 2016

- I/W Wells reported: 13,485* out of an estimated 17,500
- Active Storage Wells: 11,411
- Observation Wells: 2,320

- Wells with Tubing and Packer
  - Active Storage Wells: 1,302
  - Observation Wells: 417

*Estimated 80% response rate based on the number of reported wells

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Ex. I - 7

Environmental Research Letters

LETTER • OPEN ACCESS

A national assessment of underground natural gas storage: identifying wells with designs likely vulnerable to a single-point-of-failure

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Environmental Research Letters

LETTER

A national assessment of underground natural gas storage: identifying wells with designs likely vulnerable to a single-point-of-failure

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Keywords: underground natural gas storage, natural gas supply chain, methane, Aliso Canyon, climate change, risk assessment, wellbore integrity

Supplementary material for this article is available online

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Abstract

The leak of processed natural gas (PNG) from October 2015 to February 2016 from the Aliso Canyon storage facility, near Los Angeles, California, was the largest single accidental release of greenhouse gases in US history. The Interagency Task Force on Natural Gas Storage Safety and California regulators recently recommended operators phase out single-point-of-failure (SPF) well designs. Here, we develop a national dataset of UGS well activity in the continental US to assess regulatory data availability and uncertainty, and to assess the prevalence of certain well design deficiencies including single-point-of-failure designs. We identified 14 138 active UGS wells associated with 317 active UGS facilities in 29 states using regulatory and company data. State-level wellbore datasets contained numerous reporting inconsistencies that limited data concatenation. We identified 2715 active UGS wells across 160 facilities that, like the failed well at Aliso Canyon, predated the storage facility, and therefore were not originally designed for gas storage. The majority (88%) of these repurposed wells are located in OH, MI, PA, NY, and WV. Repurposed wells have a median age of 74 years, and the 2694 repurposed wells constructed prior to 1979 are particularly likely to exhibit design-related deficiencies. An estimated 210 active repurposed wells were constructed before 1917—before cement zonal isolation methods were utilized. These wells are located in OH, PA, NY, and WV and represent the highest priority related to potential design deficiencies that could lead to containment loss. This national baseline assessment identifies regulatory data uncertainties, highlights a potentially widespread vulnerability of the natural gas supply chain, and can aid in prioritization and oversight for high-risk wells and facilities.

Introduction

Each year nearly 28 000 billion standard cubic feet (Bcf) of processed natural gas (PNG) composed primarily of methane (CH_4), ethane (C_2H_6), other hydrocarbons, and sulfurous odorants flow through the US natural gas supply chain. Approximately 13% of PNG produced annually is injected back into underground storage reservoirs, which are either depleted hydrocarbon fields, depleted aquifers, or solution-mined salt caverns [1]. Underground natural gas storage (UGS) facilities contain 4300 Bcf in working capacity and provide a critical link in PNG operations as they bridge imbalances between supply

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and demand and mitigate ratepayer cost volatility [1–3]. Domestic natural gas production has grown 50% in the past decade and PNG storage has recently reached all-time highs [4]; however, the 2015 Aliso Canyon UGS incident has prompted new scrutiny of the nation's natural gas storage infrastructure [3].

Between October 2015 and February 2016, an estimated 99 638 (± 9300) metric tons (mt) (5.0 Bcf) of methane were released into the atmosphere from a failed storage well operating at the Aliso Canyon UGS facility near Porter Ranch, California [5, 6]. The 118-day leak resulted in the evacuation of 5790 households, and has raised new health concerns for proximate populations [7]. The emissions from the incident constitute the single greatest accidental release of climate forcing gases in US history [6] and accounted for 2.0 million metric tons of CO_2 equivalent, or about 6% of the 2015 US natural gas transmission and storage emissions from the US Environmental Protection Agency's (EPA) Greenhouse Gas Inventory (GHGI) [8]. If incorporated into the GHGI, this single incident would increase the methane emissions attributed to storage wells by 770% from the 1999–2014 baseline of 14 879 mt yr^{-1} [9].

Unintentional gas migration from UGS operations has caused fatalities, fires and explosions, evacuations, exposure to noxious odors, tropospheric ozone production [10], and releases of climate-forcing gases [11, 12]. A 2009 review of underground gas storage incidents cited 200 unintended gas migration events in the US to date [13]. The majority of unintended releases at UGS facilities, including the Aliso Canyon release, were associated with well integrity problems [11–17] (supplementary information (SI) available at stacks.iop.org/ERL/12/064004/mmedia). Presently, well-level data on incidents is not widely available and is inconsistently reported among states, limiting the opportunity to assess the rate of UGS well failure risk [13, 17].

The Aliso Canyon #25 Standard Sesnon (#25 SS) well failure is believed to have originated from the subsurface well casing [3, 18]. The well—originally completed in 1954 as an oil-producing well and repurposed for UGS in 1972—was vulnerable to a single-point-of-failure (SPF) along a portion of its production casing because: (1) a single full-length well casing was exposed directly to the outside rock formation from 990–6960 ft.; (2) gas was intentionally moved through both the outer well casing, and the inner production tubing (SI text). Injecting and withdrawing gas through both the production tubing and casing was a common practice at Aliso Canyon and has recently been identified as a common practice at other UGS facilities, particularly at older wells [3], which typically have narrower pipe diameters. An additional factor that may have contributed to loss of containment was the removal of a sliding sleeve valve in 1979 that was intended to provide a connection between the tubing and the tubing-casing annulus [3]. From industry surveys, only 3%–5% of active UGS wells utilize safety valves or sleeves below the surface [19]. The combination of these factors effectively bypassed the passive barrier protection provided by the inner production tubing, rendering the well's structural integrity commensurate to that of a single casing at 990–6960 ft.

Following the Aliso Canyon incident, the 2016 Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act mandated that the Pipeline and Hazardous Materials Safety Administration (PHMSA) promulgate minimum Federal standards for UGS operations by June 22, 2018 [18]. The Interim Final Rule (IFR)—Pipeline Safety: Safety of Underground Natural Gas Storage Facilities notes that the lack of minimum downhole regulations at UGS facilities presents an immediate threat to safety, public health, and the environment [20]. Some states had adopted regulations, but only for 'in-state' facilities that do not send gas into the interstate market [49 U.S. C. § 60104(c)]. Several states have no safety regulation for UGS facilities, and others only regulate facilities in specific geologies (e.g. salt caverns) [3]. Following the Aliso Canyon incident, California has amended design, construction, and maintenance measures to help ensure that current SPF wells do not pose an immediate threat of loss of control of fluids [21]. To inform PHMSA's rule-making process, an Interagency Task Force (ITF) on Natural Gas Storage Safety was formed to study three primary areas of concern: integrity of UGS wells, public health and environmental effects from natural gas storage leaks, and energy reliability. One of the highest priority recommendations regarding well integrity was to ultimately phase out UGS well with SPF designs [3].

Modern production and UGS wells typically contain a nested set of structural elements (e.g. casing, tubing, cement, packers, and wellheads) to form multiple barriers that collectively function to achieve zonal isolation [22]. According to the IFR, an uncertain portion of active UGS wells, like the #25 SS, are repurposed production-type wells that are facing obsolescence issues, and likely exhibit vestiges of original construction (e.g. lack of corrosion-resistant coatings) [20]. Therefore, based upon common practices prevalent during previous well construction eras [23], a portion of repurposed UGS wells may be particularly likely to exhibit designs vulnerable to SPF. Additionally, wells not designed for UGS are also more likely to lack corrosion-resistant coatings, utilize threaded pipe couplings, and exhibit insufficient strength safety margins for steel casings [20].

Identifying the prevalence of wells with design deficiencies such as single barriers would reduce vulnerability of UGS systems. Despite forthcoming regulations and reliance on UGS, baseline well-level information is not readily available, and according to the IFR, there is currently no effective means to ensure compliance with safety standards [20]. The absence of

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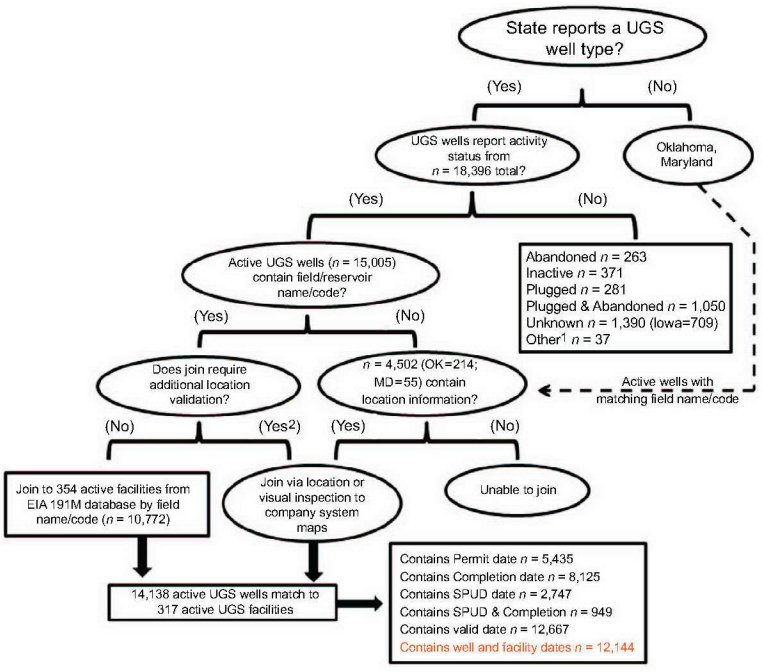

Figure 1. Framework to join UGS well and facility records. [1]Other status types include 'not completed,' 'not yet in storage service,' 'out of service,' and 'authorized but not drilled' [2]UGS well data from eight states required additional inspection to verify join to facility (see SI table 3)

such data impairs a systematic risk assessment and stakeholder management of UGS, along with refinement of EPA's GHGI [9, 24]. Improving our understanding of disparate state and Federal UGS wellbore data can aid in reducing uncertainties, and methods presented herein provide a tractable approach towards baselining national UGS well-level activity.

Here, we develop a national dataset of UGS well activity in the continental US to assess regulatory data availability and uncertainty, and perform a first-order assessment of well-level design deficiencies. To do so, we develop a framework to join disparate Federal- and state-level UGS data, and apply an indicator method to identify repurposed wells and those more likely to exhibit a SPF well design.

Methods

Storage field data

The Energy Information Administration of the US (EIA) maintains the *Oil and Gas Field Code Master List,* which provides standardized field names and codes for all identified oil and gas fields in the US [25]. We relied on the April 2016 EIA-191 M *Monthly Underground Gas Storage Report* to identify active UGS operations and matched these operations with state-level well data [1]. The EIA aggregates UGS operations by field and reservoir codes. However, not all states adhere to consistent distinctions between subterranean fields and reservoirs. Moreover, a portion of UGS operations reported by the EIA contain either duplicate field or reservoir names/codes, which indicates co-located operations within a single facility. Therefore, we include counts of unique UGS 'fields/reservoirs' and 'facilities' containing multiple co-located field-reservoirs where applicable. For interpretability, we refer to 'fields' hereafter as the subterranean entities as implied in the EIA 191 M list, whereas 'facilities' refer to UGS operations that have been joined to wells as per our methods described herein (see figure 1).

Storage well data

For most states, UGS well data were available via web download. Four states required academic use agreements via direct correspondence (SI table 3). The 'well type' variable was the primary indicator of a storage-related function [e.g. storage, injection (gas), monitoring storage]. Well types not explicitly related to PNG storage, such as liquefied gas storage, were excluded. To determine activity state, most states provided a 'status' indicator (e.g. active, plugged and abandoned, inactive, shut-in, etc.) that was used to determine the current activity state of a well.

Well-to-field join

Under the assumption that active storage wells and storage fields coincide, we attempted to join wells and fields based upon the availability and quality of well records. The data joining process is displayed in figure 1. Where applicable, well data were standardized using geodatabase aggregation and included location information, type, status, activity dates, depth, an indicator of whether a well was assigned to a facility, and unique state-well identifier (e.g. API #).

SoCalGas-5.0114

Determining well construction date

Well construction dates were generally included in state databases. We compared spud dates—the date of initial ground penetration—with permit and completion dates to determine whether completion or permitting reflected the original completion or permit, or subsequent re-completions or re-permitting. Completion occurred within a year of the spud date in 92% of 949 wells for which both spud *and* completion dates were available (SI figure 2), which suggests that these completion dates obtained largely reference the original completion of the well. Based on this relationship, we assigned the year of the oldest activity date for each well to proxy as the year of original construction.

Identifying well-level deficiencies

Repurposed storage wells were defined as wells that were originally designed for hydrocarbon production (or other non-UGS function) and were later converted to storage. To determine whether a well was designed for storage or repurposed, we compared the well's construction date to its associated field storage designation date. The storage designation date (when the facility began injecting PNG) was obtained from the *2013 Oil and Gas Field Code Master List* [25] (the most recent edition containing designation years). We examined the entire distribution of well construction dates in relation to their respective facility designation dates. From these observations, wells that predate their facility designation date by at least three years were treated as repurposed, and wells within two years of facility designation date, were treated as designed for storage.

Confirmation of SPF design would require individual well histories, which are not readily available at the national scale. Therefore, we employed an indicator method to identify well-level deficiencies inferred from initial well use, and common construction practices at the time of drilling. Based upon recommendations by the ITF, we chose a well construction date of pre-1979 to indicate the likelihood of a SPF design [3]. Therefore, repurposed wells with a construction date before 1979 were classified as particularly likely to exhibit a SPF design. We also utilized well construction eras from King and King [23] to provide context in identifying other potential well-level design deficiencies. We also compared well depth to well age to help corroborate initial well use, and to provide an internal data validation within state.

Results

Data quality and completeness

As of July 2016, the EIA reported 384 active and 23 inactive underground gas storage field-reservoirs associated with 131 unique company names within the continental US. Of these 384, 18 contained at least one duplicate field name or derivative (e.g. Lee 2; Lee 8; Lee 11) totaling 48 entries. Thus, the 384 active field-reservoirs were contained within 354 geographically confined UGS facilities. We identified 18 396 total UGS-related wells, with 14 138 'active' status UGS wells successfully joined to 317 active UGS facilities in 29 states (figure 1). Thus, 37 active UGS fields were unable to be joined to a single active UGS well. The counts above exclude the four Alaskan facilities and the 82 UGS facilities that have been abandoned, classified as inactive, or are no longer in use [26]. Of the 14 138 active wells identified, 12 440 are sited in depleted fields, with 1561 sited in aquifers and 137 in salt caverns. Eighty-two percent (82%) of active UGS wells are located in the East and Midwest regions (figure 2), driven in part by the heavy dependence on UGS during the winter season. Of the inactive status wells, 1702 were reported as 'abandoned,' 'plugged,' or 'plugged & abandoned.' For more detailed state-level metadata see SI tables 3 and 4.

A portion of UGS wells ($n = 1390$) including all wells in Iowa ($n = 709$) and most Nebraska wells ($n = 103$) reported an 'unknown' activity status. Some of these wells were successfully joined by field name to active UGS facilities, indicting active operations. However, because the well activity status could not be verified, these wells were not included in final active UGS well counts. PA, NY, IA, MN, NE, and TX recorded 'unknown' as a potential well status.

A portion of states (14 out of 29) reported specific storage-well function (e.g. monitoring/observation, injection/withdrawal). Texas provided only injection-type storage wells coinciding with EPA's Underground Injection Control program, therefore withdrawal-only and monitoring wells were not enumerated. Oklahoma did not report a 'storage' well type, and only post-1984 wells were digitized and available for download as of February 11, 2016. These 15 states equated to 6483 total active UGS wells, with 1313 explicitly listed for injection, 695 listed for monitoring/observation, and the remainder listed as 'storage' excluding Oklahoma.

Ohio UGS wells data did not include field names/codes with well records; therefore, the 3318 UGS Ohio wells were joined geospatially to facilities via company system maps (figure 1, SI table 4). Eight other states had join discrepancies that necessitated further match validation by visual inspection of company system maps (figure 1, SI table 3).

Availability of well construction activity dates varied by state (SI table 3). Of the 14 138 active UGS wells identified, 12 667 or approximately 89% contained at least one relevant construction activity date (e.g. permit, spud, completion). Only 949 UGS wells reported at least two activity dates (see SI figure 2). Approximately 60% of wells included a completion date, 35% contained permit dates, and 18% had valid spud dates. Louisiana was the only state to

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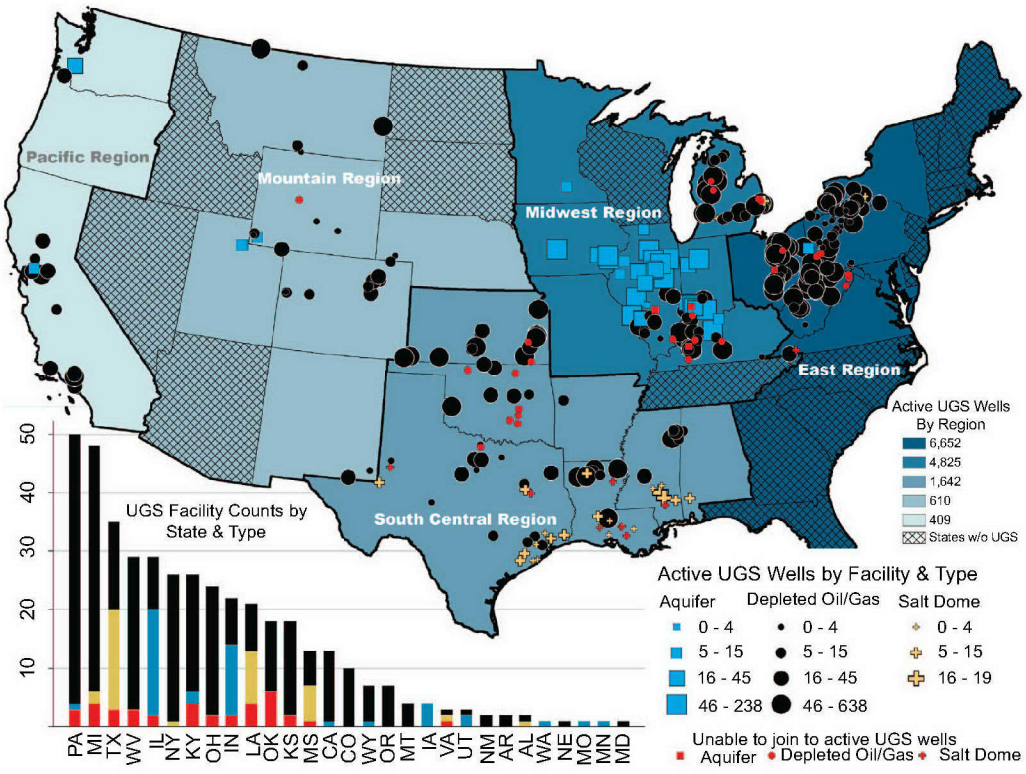

Figure 2. US underground natural gas storage facilities by geologic field type with number of active wells per facility (quantiles) and per region. In the bar graph and map, red represents the 37 fields that could not be joined to active UGS wells. Blue, tan, and black represent aquifer, salt dome, and depleted oil and gas facilities.

Table 1. Active UGS well counts by initial well use by facility-level category.

	UGS Wells[a]	UGS-Designed	Repurposed	Wells Missing Facility Date	Missing Well Date
Total	12 144	9429 (78%)	2715 (22%)	559	1471
Interstate	7021	5386	1635	255	673
Intrastate	5122	4042	1080	304	798
Aquifer	1151	1078	73	87	323
Depleted Field	10 950	8315	2635	428	1091
Salt Cavern	43	36	7	44	57

[a] reflects only active UGS wells that contain both well construction date and facility storage designation date.

provide a date for a workover-type event. Kansas did not report well construction dates for 330 active UGS wells—the most of any state—while Mississippi did not provide well construction dates for any of its 175 UGS wells. Notably, intrastate facilities, which connect to fewer wells than interstate facilities (5122 vs. 7021) have a higher rate of missing dates (table 1).

There are 76 639 entries in the *2013 EIA Oil and Gas Field Code Master List*, with 951 entries coded as 'STOR' in their remarks section indicating the field has been utilized for a storage function. Of these, 274 are listed as either 'unknown' or 'wildcat' fields across 18 states, and only 84 of the 951 indicate abandonment. Of the 354 active fields identified above, 337 reported the date the field began storage operations (designation date). The median designation year for these storage fields is 1963. Of the 12 667 wells with a valid construction date, 12 144 connect to a field that contained a valid storage designation date. Thus, well-level design deficiencies were assessed from 12 144 active UGS wells (see figure 1).

Overall, excellent well drilling depth data was provided by most states with 22 of 29 states reporting at least 95% coverage. Notable exceptions include Mississippi who did not report well depths and California with only 60% of wells reporting (SI table 3).

Well-level deficiencies

Comparing UGS well construction dates to their respective facility designation date reveals a peak of new well constructions that coincides with new UGS facility designations (figure 3). Of these, 1065 (9%) wells were constructed in the same year as their facility commenced storage operations, and 2633 (22%) of all UGS wells were constructed within the first two years of a UGS facility designation (figure 3). The increase in

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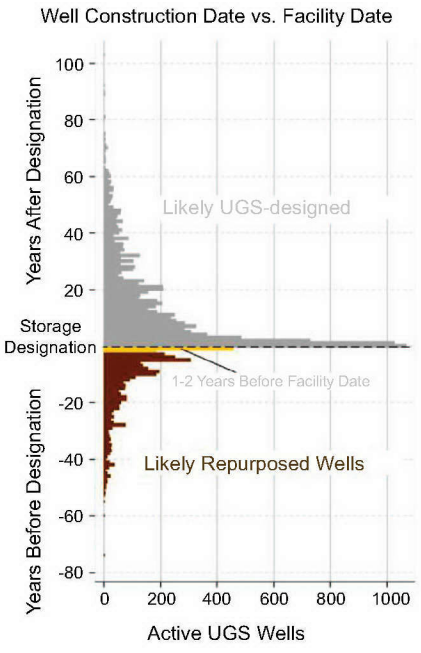

Figure 3. Number of wells (counts) constructed before and after its facilities' designation to storage date by relative years (well construction date subtracted from facility storage date).

well construction within the year prior to storage designation of their respective facility suggests that these wells were likely designed for the storage operations, or were re-completed for storage purposes. Data on well construction in the five years prior to facility storage reveal a local minima of new well construction at roughly two years before facility storage designation. While some wells constructed more than two years before storage designation may be designed for storage, a two-year cut-off of UGS-design wells is supported by the distribution of well construction relative to its facility designation in figure 3. Therefore, wells drilled at least three years before their respective facility storage designation date were classified as repurposed UGS wells.

Figures 4(*a*) and 4(*b*) rank facilities by storage designation date, and include joined active wells by construction dates. There are 114 active UGS facilities that contain only UGS-designed wells (active wells with construction dates after or within two years of the facility designation date). The shaded box in figure 4 (*a*) displays the 37 facilities that do not report a storage designation date, but did successfully join to active UGS wells with valid construction dates ($n = 559$). Though a portion of these wells may be repurposed, they were not included in final counts of repurposed wells. Figure 4(*a*) displays the 160 UGS facilities that contain at least one repurposed well.

Facility age and well age are positively associated, indicating that facility age helps to predict the distribution of well ages (Pearson's $r = 0.48$, $p = <0.0001$); however, facility age does not significantly predict of the presence of repurposed wells ($t = 0.031$, $p = 0.975$). Among facilities with at least one repurposed well, facility age is strongly correlated with well age (Pearson's $r = 0.72$, $p = <0.0001$). We observed that a majority of facilities continue to construct new UGS-designed wells after beginning storage operations, yet new well construction does not preclude operation of older, repurposed wells.

Of the 12 144 active UGS wells with adequate date information, 2715 (22% of 12, 144; 19% of active UGS wells) are classified as repurposed, of which 97% (2635) were sited in depleted oil/gas fields (table 1). An additional 266 wells with an 'unknown' status joined to an active facility would be classified as repurposed if the well status were to be confirmed. Thus, considering the 1994 active wells that did not contain valid well or field dates, and the 266 unknown status repurposed wells, the 2715 figure may underestimate the total number of repurposed UGS wells based upon this identification method. States that report an explicit storage well function account for 1135 of the 2715 repurposed wells; among these 241 were labeled as 'observation' or 'monitoring,' 41 were labeled as 'injection,' and the remainder were listed as 'storage.'

Repurposed wells are often older than UGS-designed wells (figure 5). The median age of repurposed wells is 74, compared to a median age of 48 years for UGS-designed wells and their age distributions are significantly different [X^2 (111, $N = 12\,129$) $= 7.2 \times 10^3$, $p < 0.0001$]. These results also reflect a decrease in UGS well construction over the last 30 years and a continued reliance on older wells.

Active repurposed wells can be found in 160 UGS facilities in 19 states, with 88% located in OH (902), MI (638), PA (370), NY (315), and WV (166) (figure 6). These 160 facilities connect to 79% of the total active wells and 51% of the working gas capacity in the US. Wells counts and locations of facilities with unknown status repurposed wells are indicated in gray in figure 6. Percent of wells missing sufficient date information to determine initial use is displayed in figure 6 at the state level (green pallet). Darker greens represent the percentage of wells either missing a well construction date or are connected to a facility missing designation date. Less than 10% of wells in OH, MI, PA, NY, and WV contain missing date information; however, universal activity date definitions are lacking.

An estimated 2694 of 2715 UGS repurposed wells were constructed prior to 1979, indicating these wells are particularly likely to exhibit SPF designs. Therefore, 99% of repurposed wells shown in figure 6 also meet our age-based indicator for exhibiting a SPF design, and with 88% constructed before 1960, there is a likelihood that these wells exhibit other well-design deficiencies as indicated in table 2. Notably, 661 active repurposed wells across 10 states were constructed before 1929—before well pressure-control systems and other containment methods were

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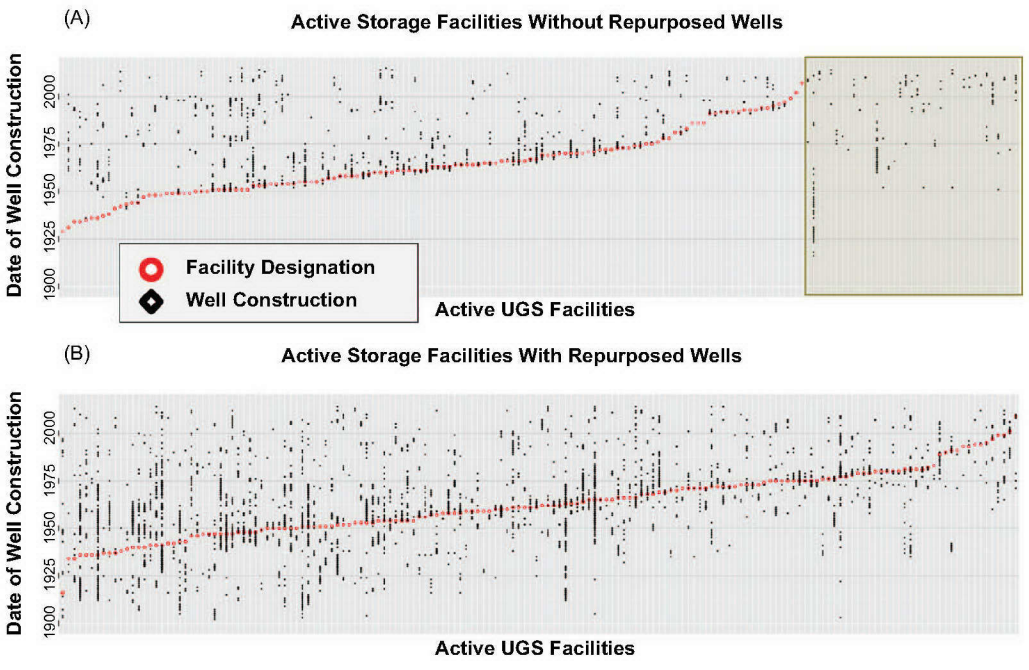

Figure 4. (*a*) Active UGS facilites with only UGS-designed wells. The gray-shaded box of figure 4(*a*) represents the facilities and associated wells where facility storage designation dates were not available. (*b*) Active UGS facilities with at least one active repurposed well as indicated by an individual well construction date predating facility storage operations by at least three years. Red circles indicate the date a facility began storage operations. Black diamonds indicate individual well construction dates.

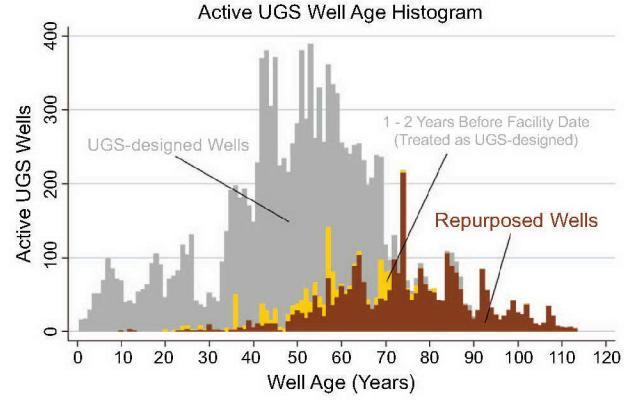

Figure 5. Active UGS well age distributions by year, colored by well design as per figure 3, with repurposed wells in dark brown, UGS-designed wells in gray, and wells drilled within two years before facility conversion to storage in yellow.

utilized. An estimated 210 active repurposed wells were constructed before 1917—before cement zonal isolation technologies were employed. These wells are located in PA, OH, NY, and WV and represent the highest priority related to potential design deficiencies that could lead to containment loss and should warrant further investigation.

Drilling well depth generally increases over time for all UGS wells ($r = -0.25$, $p = < 0.0001$) (figure 7(*a*)). However, this relationship is stronger for UGS-designed wells ($r = -0.38$, $p = < 0.0001$) compared to repurposed wells ($r = -0.19$, $p = < 0.0001$). While depth is associated with initial well design (repurposement), well age is a much stronger predictor of well design, explaining 37% of the variance compared to less than 1% for well depth. Nonetheless, well depth is important to consider in terms of wellbore integrity as pressures and temperatures generally increase with depth.

To further examine age and depth relationships, figure 7(*b*) categorizes repurposed wells by the top five states harboring repurposed wells. The clustering of wells by age, depth, and state particularly for MI, WV, and OH indicates a form of internal data corroboration between well depth and age variables. This concordance supports generalizability of findings related to initial use and design deficiencies at a state

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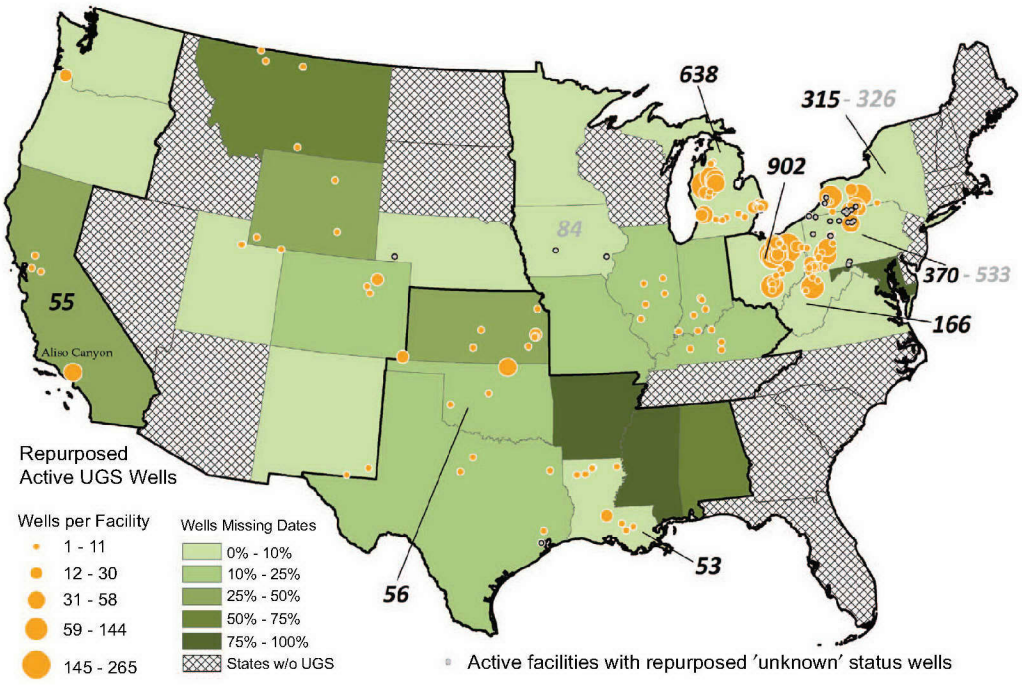

Figure 6. Counts of repurposed wells per facility symbolized by orange markers. Of the 2715 repurposed wells shown, 2694 (99%) were constructed prior to 1979, indicating a particular likelihood to exhibit SPF designs. Percent of active UGS wells missing sufficient date information is indicated at the state level by green shading. Gray markers indicate active facilities that contain at least one repurposed 'unknown' status well. Callout numbers represent counts of repurposed wells by state and includes active and unknown status well counts where applicable.

Table 2. Active UGS wells categorized by initial design and well construction eras adapted from King and King [23].

Time Era	Pre Zonal Cement Isolation (pre 1917)	Pre Well Containment (1917–1929)	Pre Gas Tight Couplings (1930–1959)	Pre Modern Cement (1960–1969)	Pre Additional Barriers; Cementing Full Strings (1970–2004)	Improved Well Integrity Assessments (2005–2015)	Total
Potential for pollution from well construction	High	Moderate	Moderate	Moderate	Lower	Lower	—
UGS-Designed	1	2	2683	2373	3938	430	9429 [a]
Repurposed	210	451	1737	214	103	0 [b]	2715
Facility Date Unknown	1	45	102	70	172	133	523

[a] 1567 active wells did not contain a valid construction date.
[b] The youngest repurposed well was constructed in 1994.

level. In contrast, NY and PA wells tend not to cluster to the same degree, which may indicate greater geologic heterogeneity and historical drilling practices, or a higher degree of data uncertainty related to date information.

Discussion

This study presents an April 2016 census of active UGS wells concatenated from disparate state, federal, and company data and information, and provides a baseline for assessing obsolescence issues related to UGS wells. We document error sources, discrepancies across 29 separate wellbore databases, and highlight key limitations and areas in need of further investigation. State-level UGS wellbore datasets contained numerous reporting inconsistencies that limited data concatenation, and our attempt to characterize data quality and uncertainties adds to a limited literature on the subject [24, 27, 28]. Overall, the majority of state regulatory bodies harboring UGS operations provide public access to standard wellbore data and information, with certain exceptions related to download restrictions, paywalls, use waivers. UGS wellbore data from eight states contained important missing variables (e.g. field name, activity status, date information) that limited the well-to-field join

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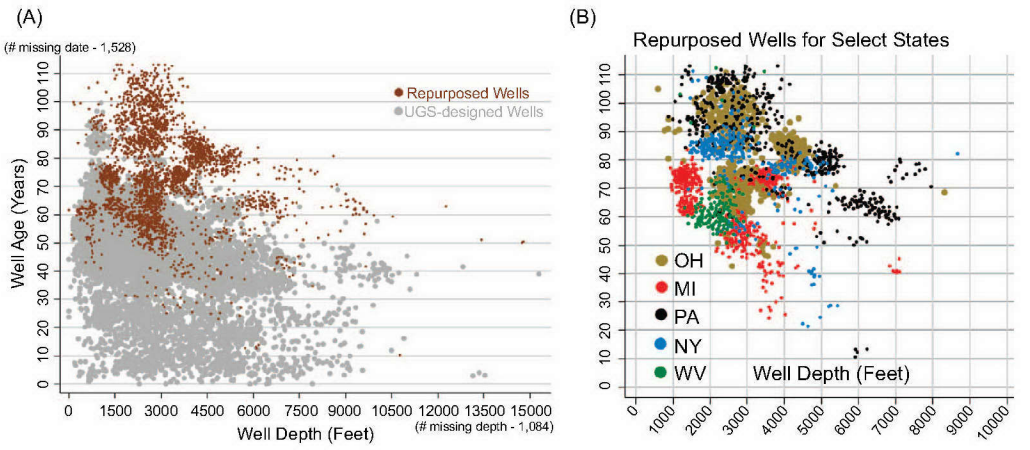

Figure 7. (*a*) Active UGS wells by age and depth below surface categorized by likely initial well design. (*b*) Repurposed wells colored by select states only by age and depth below surface.

process. Generally, these data variables were obtained following personal correspondence with data providers, with exceptions (see SI table 3). Most UGS wellbore datasets contained good coverage for: field name, status, location, operator, depth, one activity date, and API# where applicable. Generally, key missing variables included explicit storage well function, workover history, testing history, date types, and additional activity dates. Explicit characterization of well-level spatial uncertainty was beyond the scope of this study, though the peak signal between UGS field designation dates and well construction dates indicates a degree of temporal agreement between EIA field data and state well-level data. Similarly, documented imparity in data availability and quality across states and over time contributes to reducing availability heuristic and can aid regulators and stakeholders in identifying best practices.

Wellbore-level data typically does not contain information related to design elements, mechanical integrity testing, or other information necessary for a rigorous assessment of well integrity, therefore the inability to test certain assumptions remains a key limitation of this study. Given this lack of data, we developed an indicator method designed to evaluate the presence of previously identified well design deficiencies that can contribute to containment loss, using data that is consistently available on a nationwide basis. There is a potential for misclassification in identifying well design deficiencies such as SPF, however most of the assumptions in our methodology are likely conservative (see SI table 2). We relied on findings and recommendations by the ITF report on Natural Gas Storage Safety, the IFR, and the recent regulatory amendments applying to California's UGS wells.

This assessment of UGS well deficiencies is limited in scope to original well design elements such as wells not designed for UGS and wells exhibiting limited passive barrier protections. The focus on wellbore integrity assessed here is in agreement with previous studies [11–15, 29]. Our attempt to identify initial well design and SPF designs are supported by previous studies [23, 30], the Interagency Task Force on Natural Gas Storage Safety [3], and the recent regulatory amendments applying to California's UGS wells [21]. The pre-1979 well construction date as a proxy for single barrier design is supported by limited studies of well- and barrier-failures in certain locations [3, 23, 30]. Kell [30] showed that Ohio wells constructed prior to 1983 were more than twice as likely to leak (0.1%) compared to post-1983 wells with a failure rate of 0.035%. Similarly, in Texas, wells constructed before 1983 were five times more likely to leak (~0.02%) than wells constructed after 1983 (~0.004%) [30]. Though age alone does not pose a hazard if integrity is managed, further information on UGS well-level incidents is needed to assess UGS well age as a causal factor.

Our dataset contains nearly 5000 more active UGS wells than cited in the ITF report [3]. The source of this discrepancy is unclear, and is particularly apparent for OH, MI, WV, PA, and IA. Further, the methodology applied here likely underestimates the total number of active UGS wells because our estimate excludes: (1) wells with an unknown status that join to active storage fields; (2) wells not coded as 'storage' that may also be connected to storage formations (e.g. production/withdrawal only); and, (3) full storage-related well data from AK, TX, OK, and TN. Likewise, both the number of repurposed wells and the number of wells that that exhibit single barriers are likely underestimated due to the potenital misinterpretation of completion date proxying for original well construction. Additionally, explicit well function was available for only 6483 active UGS wells limiting our ability to distinguish between active injection and monitoring wells that may explain a portion of the count discrepancy.

Studies are in progress to evaluate various aspects of the natural gas midstream infrastructure [31] and

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improve existing emissions estimates and source apportionment for natural gas production and storage activities [32]. While greater precision has been achieved in attributing atmospheric methane to oil and gas emissions and fugitive leaks [33–36], the GHGI can be further improved by refining infrastructure and activity data from this sector [37]. This UGS database with identified uncertainties can improve characterization of both UGS field and well activity. With potential secondary and tertiary uses of subsurface reservoirs likely to increase in the future, data and results presented herein can inform hazard identification and risk assessments for geologic storage of CO_2, underground fluid disposal, and compressed air storage [17].

Conclusion

The natural gas leak at the Aliso Canyon facility highlights the immense hazard potential that a single UGS well can possess. We identified 2715 active UGS wells across the US that, like the failed well at Aliso Canyon, were not originally designed for gas storage. The 99% of repurposed wells constructed prior to 1979 are particularly likely to exhibit certain design deficiencies including single passive barrier protection. An estimated 210 active repurposed wells were constructed before 1917—before cement zonal isolation methods were utilized. These wells are located in PA, OH, NY, and WV and represent the highest priority related to potential design deficiencies that could lead to containment loss.

Acknowledgments

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Underground Natural Gas Storage

Integrity and Safe Operations

Prepared by:

The American Petroleum Institute

The American Gas Association

The Interstate Natural Gas Association of America

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July 6, 2016

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Introduction

The recent natural gas leak from the Aliso Canyon facility in California has prompted federal and state regulators to reexamine the regulation of underground natural gas storage facilities. The intent of this paper is to enhance the technical understanding and to provide context around the implementation of the recently developed American Petroleum Institute (API) recommended practices addressing the safe operations of underground natural gas storage facilities –API Recommended Practice 1170, Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, (API 1170) and API Recommended Practice 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, (API 1171). These standards were developed by a group of technical experts from industry and government and were published by API in 2015. They cover the design and operation of salt cavern storage and the design, construction, operation, monitoring and maintenance of depleted hydrocarbon and aquifer reservoirs.

The Aliso Canyon incident also focused the spotlight on the application of Emergency Shutdown Valve (ESV) systems as a tool for consequence mitigation of events that may occur downstream of the valve. This paper includes an appendix that provides a comprehensive review of ESV systems, including their operation, application, benefits, and reliability challenges. This appendix is intended to advance the technical understanding of ESVs and to provide context around ESV implementation.

Underground storage of natural gas is an integral component of the nation's energy system. Our nation's significant storage capacity – nearly four trillion cubic feet – enables utilities to offer clean natural gas to consumers throughout the year with reliable service and prices. Natural gas storage enables companies to adjust for daily and seasonal fluctuations in demand throughout the year while natural gas production remains relatively constant year-round. Without storage, customers, including power generators, transportation operators, and residential users, would be faced with potential supply shortages and highly variable prices.

Natural gas storage operators have consistently provided safe and reliable natural gas storage. Because of the critical importance storage plays in the nation's energy portfolio, natural gas storage operators are continually searching for new equipment, processes, and methodologies to improve safety and reliability.

This paper is the product of a collaborative effort between members of the American Gas Association (AGA), the American Petroleum Institute (API), and the Interstate Natural Gas Association of America (INGAA). Portions of this paper advocate that federal and state regulators take certain regulatory actions and refrain from taking other regulatory actions.

The information included in this paper represents the industry's best practices and decades of expertise in developing and operating natural gas storage facilities. The goal of this paper is to provide information that is instructive and helpful for regulators responsible for ensuring the continued safe and reliable delivery of natural gas for their constituents.

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Executive Summary

Natural gas storage operators have recognized a need to generate a standardized set of recommended practices to provide guidance in the areas of risk and integrity management for natural gas storage wells and reservoirs. A fundamental goal of natural gas storage management is containment of the stored gas within the facility. A team that included federal and state regulators along with natural gas storage operators developed American Petroleum Institute (API) Recommended Practice 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs (API 1171) to address the need for consistency among the industry. In September 2015, following a three-year development effort, API 1171 was published. API 1171 brings together a variety of leading industry practices for design and operations of natural gas storage facilities with risk management providing the basis. Following the release of API 1171 and PHMSA's reference to the standard in a February 2016 advisory bulletin, operators have been conducting gap analysis to compare the new standard to their own integrity management practices.

The risk-based approach to well integrity management advocated in API 1171 includes five steps: 1) Data Collection, Documentation and Review, 2) Hazard and Threat Identification, 3) Risk Assessment, 4) Risk Treatment – Developing Preventive and Mitigative Measures, and 5) Periodic Review and Reassessment. Lessons learned from historical gas storage events resulting in loss of storage containment had a role in shaping API 1171. A 2013 literature search and informal industry survey of historical natural gas storage incidents in the U.S. showed on average one major storage incident occurring per decade and less severe events occurring intermittently. While this indicates the likelihood of a major incident occurring is very low, the objective of API 1171 is to further drive down any potential risks. Recognizing that well integrity data verification and assessment must be done for every storage well in order to effectively apply the management practices in API 1171, operators are working towards uniform application of the standard.

Storage well integrity management programs are developed with a life cycle approach that includes well design, construction, commissioning, operations, maintenance, and abandonment using effective procedures, training, documentation and records retention and relying on the knowledge, skills, and experience of the personnel and the organization managing the facility. Design factors employ one or more barriers such as casing, the wellhead, and cement, to provide containment of storage gas. Specific designs using equipment, such as emergency shutdown valve systems or tubing and packer well configurations, must be evaluated using the risk management process as these designs add potential risk and no single specific approach provides a panacea to mitigate all potential integrity issues. New and existing designs can both be successfully employed within a risk-based integrity management program. Risk assessments are used as a basis for developing the integrity demonstration, verification, and monitoring tasks and for evaluating their frequency requirements. The operator's approach addresses the need for re-evaluation of risk-based conclusions, and the frequency of monitoring tasks. These monitoring tasks and other operating practices are performed by trained personnel and require documentation and continual improvement processes as part of storage integrity management.

Operators have projected full conformance with API 1171 following a final rulemaking could take 7-10 years, taking into account the gap analysis currently underway to compare the new API 1171 to individual integrity management practices, and the development and implementation of risk assessment techniques applicable to an operator's specific storage fields, integrity management plans, inspection

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and maintenance practices, emergency management plans and storage well blowout contingency plans, and procedures for well and reservoir integrity tasks and activities (management of change, training and competency programs).

Overview

The underground storage of natural gas is a critical component of the natural gas supply system in the United States. On the highest demand days, storage delivers about half of the natural gas consumed. As natural gas becomes an increasing part of our national power generation and energy portfolio, these storage assets will continue to play an important role. Approximately 400 gas storage facilities, comprised of almost 17,500 storage wells provide service today. Eighty percent of storage facilities employ geologic formations, or reservoirs, that originally contained natural gas and/or oil reserves and were converted to depleted reservoir storage. The remaining facilities are engineered for gas storage using either deep, water-filled geologic formations, aquifers, or caverns that have been created in salt formations using a solution mining process[1]. This paper focuses on natural gas storage well integrity in depleted reservoir and aquifer facilities and provides an in-depth discussion of Emergency Shutdown Valve systems in onshore, natural gas storage wells.

The overall objective of a storage facility integrity program is to help ensure and confirm that storage gas is confined in the system. A storage facility can be divided into four distinctive physical components: the reservoir, the well(s), the storage pipeline system and the compressor station. The latter two are regulated by the U.S. Department of Transportation (DOT) under 49 C.F.R. Part 191 and 192 and are not within the scope of this paper. The first two physical components of a gas storage facility are addressed in American Petroleum Institute (API) Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (API 1171). API 1171, which was published in September 2015, represents a three-year effort by a working group including representatives from DOT's Pipeline & Hazardous Materials Safety Administration (PHMSA), the Federal Energy Regulatory Commission (FERC), state regulators, and industry to develop natural gas storage well and reservoir integrity standards that combine consensus best practices, regulations, and concepts adapted from risk management and safety management systems.

This paper further describes natural gas storage well integrity. Natural gas storage well integrity management programs are developed with a life cycle approach that includes well design, construction, commissioning, operations, maintenance, and abandonment using effective procedures, training, documentation and records retention and relying on the knowledge, skills, and experience of the personnel and the organization managing the facility. Safety and integrity of storage wells are managed using a risk informed approach that includes identifying threats and hazards at each site, analyzing and evaluating the risk, and developing preventive and mitigative programs to manage the risk[2].

As part of the continual improvement process described in API 1171, this paper describes processes in place or under development by operators. API 1171 was finalized in September of 2015 and the industry is in a foundational state developing conformance with API 1171. Operators are at various stages in their efforts to enhance their existing integrity management processes to achieve conformance with the

[1] Additional background information on natural gas storage in the United States is provided in Appendix 1 via a brochure, "Supporting the American Way of Life- The Importance of Natural Gas Storage", developed as a joint effort of the American Petroleum Institute (API), the Interstate Natural Gas Association of America (INGAA), and the American Gas Association (AGA).
[2] Section 8 of RP1171 describes the risk management approach for storage wells and reservoirs.

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robust consensus standards established in API 1171. These efforts begin with a gap analysis to compare the new API 1171 to the operator's individual integrity management practices, and then move to the development and implementation of risk assessment techniques applicable to an operator's storage fields, integrity management plans, inspection and maintenance practices, emergency management plans and specific storage well blowout contingency plans, and procedures for well and reservoir integrity tasks and activities (management of change, training and competency programs). Operators as referenced in this paper are seeking to conform to API 1171 and have estimated that conformance can be achieved within seven to ten years of a final rulemaking.

The following discussion is organized into four sections beginning with a description of the storage well integrity management process and its strong relationship to risk management process. Lessons learned from historical storage well gas release events are reviewed in the second section. An examination of storage well integrity design factors is contained within the third section. The final section reviews operational approaches to managing storage well integrity.

1. Natural Gas Storage Well Integrity Management Process & Risk-Based Approach (API 1171 Section 8)

The natural gas storage well integrity management process starts with a comprehensive risk assessment. The assessment includes data collection, hazard and threat identification, likelihood of occurrence estimation, and consequence severity determination. Preventive, mitigative and monitoring practices are developed that can reduce the potential for an integrity compromising event. Periodic review and reevaluation of the risk assessment and the effectiveness of the safety management program complete the process[3].

The risk management program discussed below and incorporated in API 1171 has three fundamental components - physical plant design, processes and human factors. The physical plant includes design features with the ability to contain pressurized storage gas. The process component includes the technical and procedural systems that promote the identification and mitigation of threats while also identifying and managing the consequences in the design, construction, commissioning, operations and abandonment phases of a storage well life cycle. The processes also include audit procedures, emergency response plans and a continual improvement cycle. Neither the physical plant nor the processes would be totally effective without effective management of human factors. Operators develop staff knowledge, skills and abilities to safely and efficiently manage their responsibilities for storage well integrity. A management team that fosters a robust health and safety culture is important to the success of human factor management. Ineffectiveness or failure in any one of these three components can lead to loss and/or escalation of a minor event into a potentially major incident.

The operator's risk assessment must take a holistic approach to storage well and field integrity to effectively manage risk. It should be noted that while this paper is focused on addressing the integrity of storage wells, some of the threats and preventive and mitigative measures pertain to both the storage wells and the storage reservoir. An example would be third party damage, such as vehicular

[3] Appendix 2 is a flow chart from RP1171 presenting the various steps for well and reservoir integrity management.

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impact to a wellhead (well risk) or a third party oil and gas producer drilling through the storage reservoir to a deeper formation (reservoir risk).

Step 1- Data Collection, Documentation and Review (API 1171 Section 8.3)

Good practices in well integrity management involve the collection and maintenance of information for each storage well for the life of the facility. Importance is placed on understanding how the well was originally drilled, configured, and completed; the purpose of subsequent reconditioning work and other maintenance activities; the characteristics of the geologic environment encountered by the well; reservoir and injected fluid properties; well performance capability; and wellsite information. Operators integrate these data to develop a holistic understanding of the threats and hazards presented to each storage well and to the entire storage facility.

Types of data collected include geologic information on the formations penetrated by the storage well, wellbore configuration and completion data (e.g. casing characteristics, setting depths, cement, etc.), pressure and volume data on the flow capability of the well, annular pressure and/or volume data, reservoir fluid analysis, wellhead design, and other characteristics of the subsurface in addition to information about the wellsite. Sources of data include storage operator records, third party records, and information filed with the state geologic survey and/or oil and gas regulatory agencies.

Step 2- Hazard and Threat Identification (API 1171 Section 8.4)

A hazard is a potential situation or condition that could cause the loss of or damage to a natural gas storage well. A threat can be caused by activation of a hazard. Note that due to the variety of well designs and the diverse geologic and geographic settings of wells, hazards and threats vary from one storage well to another as well as from one facility to another.

Appendix 3 includes a detailed listing of common threats and hazards to storage wells. This list was developed for API 1171 and included input from operators representing the majority of storage wells in the United States with hundreds of thousands of well-years of operational experience. API 1171 encourages operators to utilize the list and supplement it as necessary based on well-by-well, site specific assessments. Operators are also encouraged to consider the potential for interactions between specific threats and/or hazards. A lack of data is not used as justification to exclude a specific threat.

An individual storage well has one or more design features to contain the storage gas inside the wellbore and in the storage reservoir. Physical components of a well that act as barriers to the gas and protect against potential loss of containment events are the casing in the well and cement behind that pipe. Potential consequences from the failure of containment include storage gas escaping to freshwater formations or to the surface at or near the wellhead. In addition to those downhole features, the wellhead is designed to control the flow of gas from the wellbore to the pipeline system. The wellhead design can also provide access to the annulus to identify potential loss of containment from the production casing. Redundant or multiple barriers can promote higher reliability as a second barrier, such as cement behind the production casing can contain the gas if the first barrier fails. Storage operators can monitor parameters such as operating pressure, temperature and flow conditions to confirm normal operating conditions and limits and to detect abnormal conditions. Assessing the risk presented by an individual well, therefore, incorporates both the type and the quality of design features

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that exist, in addition to the operator's procedures and personnel training. Some causes of the loss of containment of storage gas, based on operational experience, are discussed later in this paper.

Operators will periodically review the threats and hazards for each well to account for changes in perception of likelihood or consequence of event occurring. This review also provides the most up to date information for the risk assessment. As an example, operators will review events in the storage industry and evaluate the risk of a similar event occurring with their storage wells.

Step 3- Risk Assessment (API 1171 Section 8.5)

The operator's risk assessment uses tools and techniques that evaluate and prioritize risks so as to direct risk management activities toward promoting the functional integrity of the storage wells.

The risk assessment method includes:

1. Identification of potential threats and hazards to a given storage well,
2. Evaluation of the likelihood of events and consequences,
3. Risk ranking to develop preventive and mitigative (P&M) measures to monitor and/or reduce risk,
4. Documentation of risk evaluation and decision basis for P&M measures,
5. Provision for data feedback and validation, and,
6. A continual improvement cycle by way of periodic risk assessment reviews with updated information so as to evaluate the risk management effectiveness, and to modify/update the potential threats and hazards and P&M measures needed to address these threats and hazards.

Step 4- Risk Treatment- Developing Preventive and Mitigative Measures (API 1171 Section 8.6)

Risks to a specific storage well can be effectively managed with P&M measures which reduce the likelihood (preventive), reduce the consequence (mitigative), or by a combination of both. Appendix 4 contains a table adapted from API 1171 listing the common P&M measures for different threats or hazards. This list was collaboratively developed by operators owning the majority of storage wells in the United States and represents hundreds of thousands of well-years of experience in managing well integrity risks. The list also incorporates efforts by operators to develop new technology and represents the currently available tools, techniques and practices for storage well integrity management. Operators will continue to support new technological developments pertaining to well and reservoir integrity.

Operators are using the P&M measures identified in API 1171 to determine the applicability of each P&M measure to their wells and are supplementing the list as necessary for site specific conditions. Operators will then employ applicable API 1171 P&M measures and train their personnel on the procedures related to those measures.

Step 5- Periodic Review and Reassessment (API 1171 Section 8.7)

Storage wells can be in operation for many years and while the passage of time itself does not pose an additional threat if facility integrity is managed, the threats to each storage well can and likely will change over time. Examples include surface encroachments on well sites due to farm land being converted into housing developments or the discovery of new productive oil and gas formations below

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the storage reservoir leading to third party drill activity through or in proximity of the storage formation. Therefore, operators periodically review the integrity management programs and risk assessments to update identified potential threats and to evaluate utilization of P&M measures to address the risk. The review interval is short enough so that the data and information brought into the analysis are meaningful. Operators conduct their risk management as an ongoing activity.

Operators also maintain a continual improvement cycle for risk management activities that incorporates new procedures, practices and technology when relevant to a specific storage facility. Experience has shown that significant technological advancements can occur over the long life of a storage well. Operators stay abreast of these developments and incorporate new technology and best practices as appropriate.

2. Lessons Learned from Historical Underground Natural Gas Reservoir Storage Well Events (API 1171 Sections 8.4 and 8.7)

Unplanned releases of natural gas from underground storage wells, while rare, have occurred. A literature search of historical release events was conducted in 2013 to better inform the API 1171 development team. The information compiled came from publically available sources and an informal survey of underground storage operators. The informal industry survey covered nearly 14,000 wells contained in 226 fields, and represents a sampling of over 80 percent of the natural gas storage wells in the United States. The publically available information came from newspapers, Geologic Survey reports, state oil and gas inspector notes and other available public information. These statistics exclude the Aliso Canyon incident, which commenced October 2015, after API 1171 was published.

A process safety tier ranking system referenced from API RP754, "Process Safety Indicators for the Refining and Petrochemical Industries" second edition, April 2016, (RP754), can be used to categorize the incidents from the informal industry survey and publicly available information review referenced above. Although RP754 is written for the refining and petrochemical industries, the application of the tier structure has merit since the storage incidents referenced herein represent loss of product containment. Tiers 1 and 2 are lagging indicators and are suitable for nationwide public reporting. Tiers 3 (challenges to safety systems) and 4 (operating discipline and management system performance) are leading indicators used by companies for their internal review and improvement.

As defined in RP754, Tier 1 Process Safety Events are more significant incidents that result in the unplanned loss of containment and one or more of the following consequences:

- An employee, contractor, or subcontractor "days away from work" injury and/or fatality;
- A hospital admission and/or fatality of a third-party;
- An officially declared community evacuation or community shelter-in-place including precautionary community evacuation or community shelter-in-place;
- Fire or explosion damage resulting in greater than or equal to $100,000 [4]of direct cost.

Tier 2 Process Safety Events are unplanned loss of containment events with a lesser consequence than Tier 1 that result in one or more of the following consequences:

[4] This reporting threshold is referenced from API754, Part 191's incident reporting (191.3) threshold is $50,000 in damage, which is a subset of direct cost. The authors are not suggesting modification to the reporting definitions in 191.3.

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- An employee, contractor or subcontractor recordable injury;
- Fire or explosion damage resulting in greater than or equal to $2,500 of direct cost.

The data search for unplanned storage well releases identified 61 events between 1953 and 2010. A breakdown of the incidents by decade along with an application of the RP754 Tier 1 and 2 structure (the severity of the incident) is shown in Table 1.

Decade	Number of Incidents	Injuries	Fatalities	Tier 1 Incident	Tier 2 Incident
1950-1959	2	0	0	0	1
1960-1969	10	7	4	1	4
1970-1979	15	3	0	2	9
1980-1989	7	0	0	0	3
1990-1999	18	5	0	1	8
2000-2010	9	0	0	0	5

Table 1 – Storage Well Incidents by Decade

It is worth noting that the largest number of injuries and fatalities is attributed to a single incident in 1969. The two Tier 1 incidents in the 1970's were related to two separate well fire incidents resulting in burns to workers. After the 1970s, there was one Tier 1 incident in 1997 that was due to the overpressure of a brass valve which blew apart and injured two workers.

Based on the event data reported since 1990, and taking into account the Aliso Canyon incident, the likelihood of an event occurrence, calculated using the Center for Chemical Process Safety [5] (CCPS) American calculation for hazardous process facilities, results in a "very unlikely" to "extremely unlikely" or "remote" classification. Implementation of API 1171 is expected to reduce this likelihood further.

Table 2 furthers the analysis by organizing the events according to the threat categories as shown.

Threat	Occurrences
Well Interventions	20
Wellbore Leak	22
Third Party/Outside Forces	6
Design	7
Wellhead/Gathering	5
Unknown	1

Table 2 – Storage Well Threats and Occurrences

This analysis shows about 30 percent of the events occurred as a result of well interventions (i.e., activities associated with the operator entering the well for some type of remedial, valve maintenance, or other work) and another 30 percent were caused by issues with the downhole tubulars. Of the

[5] (CCPS) American Institute of Chemical Engineers (AIChE); CCPS order of magnitude event frequencies align to qualitative descriptors: "extremely unlikely to remote" is <1E-05, "very unlikely" is in a range of 1E-05 to 0.99E-03

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reported wellbore leaks due to issues with downhole tubulars, 12 were of undocumented origin, four were due to casing corrosion, four due to mechanical issues, and two were the result of manufacturing defects.

Fifty-one of the reported events included an estimate of the length of time for the event to be resolved. Eleven incidents took longer than a month to contain and seventeen were resolved in less than 30 days. Twenty-three events were contained within two days with most of these contained in less than 24 hours.

Of the 61 events identified in this review, one, in 1969, resulted in seven injuries and four fatalities to the public. In 21 events, the general public was impacted through road closures, water supply replacements, building damage and evacuation of homes.

It is recognized that the frequency of Tier 1 and 2 incidents has remained flat over time. Operators continually learn from historical events which, among other things, prompted the development and use of improved casing inspection tools.

Operators currently employ a variety of methodologies to ensure the functional integrity of the storage wells they operate. The storage facilities are designed to operate within maximum operating pressure limits of the reservoir and all connecting elements from the well, wellhead assembly, and the connected pipeline system and any ancillary equipment. The development of API 1171 represents a significant effort to improve upon the process safety record through the use of a standardized risk-based approach to natural gas storage integrity.

3. Storage Well Design Factors (API 1171 Sections 6.2)

A. Wellhead Equipment (API 1171 Sections 6.2.1, 6.2.2, 6.2.3)

All wells include a system of surface-mounted valves to control flow, commonly referred to as the wellhead. Wellhead configurations have proven to be effective barriers to control flow of stored natural gas. The underground storage of natural gas began in the United States one hundred years ago. Originally, many surface-mounted valve assemblies were referred to as production style and were often fabricated in the field by welding pipeline components and valves to the well itself. Over time operators have replaced the design of the original well control configurations with more standard and conformance tested equipment. Today, the wellhead equipment used for new underground natural gas storage wells consists of equipment that conforms to API Specification 6A standards. The wellhead equipment is composed of a number of valves and components that isolate the well casings within the wellhead assembly and provide control of the well at the surface. This control allows the well to be open to or shut from the pipeline system and provides for the connection of equipment for any potential future remedial well operations. Ports on the wellhead assembly allow for the measuring and monitoring of pressures and flows from the different casings, including the flow string itself and annular space between the casings. These API 6A standard wellheads contain a master valve that allows for full diameter access to the production casing for future inspections of the well casings.

Other factors included in the specifications of the wellhead and related equipment include the expected flow rates and flow paths, potential future increases in operating pressures, any anticipated treating or

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stimulation pressures, chemical composition of fluids injected and withdrawn (including those used for treating or stimulation) and servicing and maintenance needs for the wellhead as identified by the original equipment manufacturer. In designing the well, wellhead, and related equipment, operators also evaluate the future inspection, servicing, and maintenance needs for the well. Included in this evaluation are valve type and sizing factors to allow for mechanical inspection of the wellbores.

Another aspect of well design is an evaluation of the corrosive potential of any formation fluids that may enter the well or annular space of the well along with decisions made whether or not to induce current on the well casing as part of a cathodic protection system. In addition, the assessment of erosive impact of formation particulates or stimulation treatment materials is included with the well component design.

B. Well Configurations (API 1171 Section 6.3)

As with storage wellhead assemblies, storage wells have existed for many decades in various configurations. The storage well provides isolation from groundwater, controls wellbore conditions, isolates the storage gas within the storage reservoir and allows for injection into the reservoir or withdrawal from the reservoir.

Operators refer to API TR 5C3, which provides technical details regarding the strength of casing and tubing, to design casing configurations for their wells. Typically the oil and gas regulations within a given state prescribe the minimum requirements for well completions. The API published burst values in the 5C3 bulletin include a built-in 12.5 percent safety factor to allow for the manufacturing tolerance of the pipe wall. These published burst values are used by operators to confirm that their well completions can withstand the maximum anticipated operating pressures and temperatures of their wells. In many cases, storage operators construct storage wells with casings rated for significantly greater pressure containment than the pressures expected for normal operations of the storage well. Operators utilize commonly available casings, which may have higher pressure ratings than minimally required, simply because of their availability. Some operators may stimulate wells at higher pressure in the future and factor this plan into the original casing design. Operators will verify casing capability to withstand stimulation pressures prior to stimulation. In any case, operators verify that the ratings of the casings installed in the well exceed the anticipated pressure containment needs.

Storage wells extend from a few hundred feet to several thousands of feet beneath the surface. The wells connect the underground reservoir rock, where gas is stored in the porous and permeable rock formations, to the surface wellhead assembly, the system of valves and components that connect the well to the pipeline system.

Storage wells are constructed in a concentric manner with larger diameter casing installed nearest the surface and smaller diameter pipe extending from inside to deeper underground formations. The casing is composed of sections of pipe known as joints that are about 30 - 40 feet long and form the casing string that connects the reservoir to the wellhead. The joints are typically screwed together with engineered connection collars that include thread compound to assist in providing a seal for each joint, ultimately forming a continuous barrier along the entire casing string. This casing string confines the stored natural gas inside the pipe and also acts to prevent any external substances from entering the well.

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As specified in API 1171, a new storage well contains at minimum two casings; the surface casing and the production casing. Cementing these casing strings, in part or wholly to the surface, provides an additional zonal isolation barrier by sealing the void space between casing strings and/or between casing and the rock formations. This system provides isolation of the stored natural gas from the surrounding rock formations, allowing the production casing to contain the flow of gas in and out of the storage reservoir. The casing and cement well barrier elements [barriers] provide the foundation for managing well integrity.

The following describes an example storage well configuration:

- Conductor casing: the conductor casing is the widest diameter pipe used in the well and is of sufficient size and strength to control the near-surface movement of earth and provide stability for future drilling operations. This pipe can be cemented in place by grouting to the surface and is not connected to the wellhead.
- Surface casing: the surface casing's main purpose is to isolate the well from sources of fresh water and to provide additional stability for deeper drilling of the well. This pipe is typically screwed together and usually cemented in place from the bottom to the surface by displacement.
- Intermediate casing: in some cases, a well may contain an intermediate casing string to isolate the well from coal, salt, other mineral deposits, and/or gas bearing zones, to control subsurface conditions and to provide additional stability for deeper drilling of the well. This pipe is typically screwed together and often cemented in place from the bottom to the surface by displacement.
- Production casing: Inside these other casings is the production string which provides access to the storage reservoir formation itself. This string provides isolation of the natural gas that is being stored. Typically, production casing is screwed together and cemented in place from the formation, either to the surface, to a level above the storage formation deemed adequate for containment, or to the casing set point of an intermediate or surface string by displacement. The casing is thus sealed in place and prevents any flow of gas or other fluids in the annular space between the pipe and the surrounding rock formation.
- Production tubing: In some cases, a smaller diameter string of pipe known as tubing, which like the casing is normally threaded pipe joined by engineered connections, is installed inside the production casing. Gas can be injected or withdrawn through the tubing, the tubing/production casing annulus or both depending on the well configuration. If tubing is used, the velocity of flow is greater due to the reduced cross sectional area of the tubing as compared to the casing, and liquids can be lifted from the bottom of the well to the surface. In this case, tubing is not cemented in place, but hangs from the surface wellhead assembly or is set on a packer which has anchoring slips and a rubber packing element that seals the space between the tubing and production casing. Tubing set on a packer seals the storage formation pressure and fluids from the production casing. The annular space between the tubing and production casing can be filled with fluid and inhibitors to protect against corrosion. If an operator drills and completes a new well with a tubing on packer completion, and the well requires high deliverability to meet design flows, the casing design results in larger diameter

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pipe than would be the case for a well with similar deliverability completed without tubing. However, retro-fitting wells with tubing on packer completions results in a detrimental effect on service reliability, on peak deliverability and potentially to seasonal working gas capacity, as the cross-sectional area available for flow is reduced. An operator could drill substantially more wells to make up for the loss in order to maintain deliverability and turnover requirements. Since additional wells would be required, the overall risk impact with the storage field could be increased. An operator's site-specific risk assessment provides guidance for a decision on casing/tubing requirements for the design of new wells and the applicability for existing well completions.

C. Zonal Isolation (API 1171 Section 6.2, 6.3, 6,4)

The storage well casing, cement and wellhead assembly provide the zonal isolation, or barrier envelope, for a well. These barriers are designed to withstand the maximum operating pressures, including stimulation or treatment pressures, temperatures, flow rates, flow compositions and provide the necessary isolation of the stored natural gas from the well's surrounding environment. The well casing and wellhead assembly are confirmed to have mechanical integrity through testing and maintenance. In addition to API 1171, ISO Technical Specification document 16530-2 "Part 2: Well Integrity for the Operational Phase" includes a section defining well barriers in more detail. See Appendix 5 for examples of gas storage well configurations. Example A depicts a well showing a wellhead assembly on the surface connected to the storage zone through the production casing inside surface and conductor casings with cement sealing the annular spaces between formation and pipe and between the different casings. Example B depicts a well showing a wellhead assembly on the surface connected to the storage zone through both production casing and tubing inside surface and conductor casing. Cement is shown in Example A between the production casing and formation and between the casings. The tubing is not cemented in place and may or may not contain a packer element at the bottom to seal the annular space between tubing and casing. Without a packer, flow could occur through the tubing and/or the tubing/casing annulus; however, with a packer flow could only occur through the tubing.

On the surface, the wellhead assembly contains a master valve that provides isolation of the well from the atmosphere and the pipeline connection. The operator in some cases may decide to install tubing in a well that can either be used as a velocity string to help remove fluids or set on a packer to provide a seal for the annular space between the tubing and production casing. Additional barriers are the seals within the wellhead itself and other valves on the wellhead assembly.

The operator evaluates the entirety of the barrier envelope when making decisions regarding the inclusion of an emergency shutdown valve (ESV). A variety of criteria, as more fully described in Appendix 6, are evaluated in determining the need for an ESV in any particular well. These factors include, but are not limited to, the flow potential and flow composition and the proximity relationship to dwellings or human congregation areas, the accessibility of the well for emergency response including the proximity of the well to other wells or structures, the proximity to vehicular, air or rail traffic and industrial sites, the added protection of other barrier options, and the risks of installing and servicing the ESV itself.

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Each of the above barriers is a component of protection to maintain the isolation of the stored gas in the well and to prevent any contamination from entering the well itself from the surrounding rock formations. Storage operators design the well completions to provide zonal isolation that meets or exceeds regulatory requirements of individual state oil and gas agencies.

D. Cementing Practices (API 1171 Section 6.4)

In addition to the casing in the well, the purpose of cementing is to provide a seal, or zonal isolation, primarily by preventing movement of gas or other fluids vertically behind the casing, which is an important part in maintaining well integrity. Over time, installing a seal around casing has evolved from some instances where operators placed a gelled fluid or drilling mud into the annular space between casings or casing and the rock formation to a more refined and specific process. Today, cementing is the process of mixing a slurry of cement, water and cement additives and placing it in the well by pumping it through the casing to fill the annular space between the casing and formation or previous string of casing. Once the cement has cured to sufficient compressive strength, the cement provides support to the casing, and bonds the casing to the formation for zonal isolation. Cement provides an additional barrier element and can also protect the casing from external corrosion. Cement used in well construction meets or exceeds the requirements of API Specification 10A or ASTM C 150/C 150M Standard Specification. These specifications list chemical and physical properties for different classes of cements.

E. Cement Design (API 1171 Section 6.4.4)

Placement of cement so that it completely surrounds the casing and removes all drilling mud from the annulus is important to a successful cement job. Operators face numerous challenges with cementing casing that affect the placement of cement behind the casing. Drilling fluid and borehole quality can affect both the running of casing and the displacement of the drilling fluid during cementing operations. The stability of the borehole could be compromised due to sensitivity with the cementing materials and related fluids chemistry which may lead to caving and the inability to circulate and effectively place the cement. All of these challenges are factored into the risk assessment for the well and incorporated into the cement design.

Operators use casing hardware to assist in centralizing the casing and placing uncontaminated cement around the casing. A casing shoe, which helps guide the casing through the wellbore to bottom and protects the bottom of the casing from damage, is run on the bottom of the casing. Centralizers are used in an effort to offset the casing from the borehole wall, since it is difficult to remove drilling fluid and place cement in areas where the casing is too close to the borehole wall. Float equipment is used to restrict back flow into the casing after cementing and prevent cement contamination near the shoe of the casing. Wiper plugs provide separation between the cement slurry and drilling fluids, wipe the inside of the casing of drilling fluids and cement and provide an indication of the end of displacement of the cement slurry.

Slurry design takes into account the amount of cement needed for zonal isolation and the cement top location. Pore pressures and fracture gradients are also evaluated in the slurry design. Inadequate formation competence could lead to an inability to support hydrostatic pressures of columns of cement

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slurries, leading to formation breakdown, loss of cement column and the inability to place the cement as desired. Cementing back to the surface from total depth can provide additional barriers, annular isolation and additional burst protection over and above burst strength of the casing. In deeper wells, high downhole pressures due to the hydrostatic weight of the cement slurries, combined with additional friction pressures of the viscous slurries, can lead to lost circulation or inadequate annular fill. Operators can use mixed density cements, pumping a lighter weight lead cement that reduces the hydrostatic weight of the full cement column in the well, to mitigate potential lost circulation or inadequate fill. Operators may also use stage tools in the cementing design that allow sections of the well to be cemented at separate times or in stages to reduce the hydraulic head. The operator's risk assessment for the well helps them determine the best method to use in the cement design for a specific well.

Pre-flushes, high annular velocities, high slurry densities and pipe movement are other techniques that operators apply to aid in effectively removing the drilling fluid from the hole during cementing. Pre-flushes help to avoid incompatible fluid interactions with drilling mud and cement. High annular velocities with high slurry densities provide more energy to remove gelled drilling fluids and pipe movement aids in coating the cement slurry on all sides of the pipe. API 65-2 "Isolating Potential Flow Zones During Well Construction," Section 5, "Cementing Practices and Factors Affecting Cementing Success", discusses in more detail many of the areas that operators address for placement of the cement. Competent cement is an important component of the barriers that can contain storage gas if the production casing develops an integrity issue.

When zonal isolation is not achieved or the casing is compromised during the cementing process, operators utilize remedial techniques to repair the wells and provide isolation. For wells with cement to the surface, remedial techniques may include internal patches to repair casing defects or squeeze cementing to improve zonal isolation. Operators evaluate the remediation required along with any associated risks in determining the correct actions to take to repair a well. Those risks can include reduced internal diameter of the casing below the point of remediation and creation of new potential leak paths.

F. Cement Evaluation (API 1171 Section 6.4.6)

Operators use cement evaluation techniques to determine the placement and quality of the cement in a well. For a new or reconditioned storage well, API 1171 requires operators to use a cement bond log (CBL) or other means to determine the placement and bond, or sealing quality, of the cement. API TR 10TR1 reviews various types of cement evaluation logs that operators use, including the CBL, and their features and limitations. New well construction designs should include running the CBL log during the completion process while the wellbore is still full of drilling or circulating fluid. Existing wells can also be evaluated with CBL tools. The historic sonic-based CBL technology requires a liquid-filled wellbore to enable the tool to perform properly. Filling the wellbore with fluid includes added risks, from the introduction of fluid to the well, removing the fluid from the wellbore and possible corrosion from residual fluid left in the wellbore. Operators evaluate risks prior to any well intervention and incorporate these prior to running the CBL. New CBL technology, currently in the field testing mode, does not require a fluid-filled wellbore and, once validation is confirmed, may be a promising alternative for certain aspects of casing-to-cement evaluation. This new tool does not currently evaluate the cement-to-formation bonding, which the older CBL technology may provide.

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G. Well Closure (Abandonment) (API 1171 Section 6.7)

A storage operator may choose to permanently close a storage well. This closure is referred to as plugging and abandoning the well. Once this decision is made, the operator designs a well closure plan to isolate the well from the storage zone and any other strata that the well penetrates. This closure of the well removes the well as a conduit for the flow of fluid between different zones penetrated by the well or from one of these zones through the well to the surface. State oil and gas regulations often specify the requirements for well closure operations.

Cement plugs, mechanical plugs or a combination of both are used to isolate the storage zone. Cement plugs are designed to be of sufficient length to provide a seal, which provides this isolation. In some areas, local regulations may require minimum plug lengths for well closure. Regulations may also require a plug across groundwater zones near the surface. Some operators close the well by filling the production casing with cement to surface. In the well closure design, operators must also account for any formations behind un-cemented casing in the well and for any equipment or hardware in the wellbore that may limit the operator's ability to properly place the cement plug. Prior to beginning well closure operations, operators kill the well and make sure that it is in a static condition. After completing the placement of plugs and allowing the cement to cure, operators verify the location and the seal of cement plugs in the well and then the well is capped and left with an identification monument, as required by regulations. After abandonment, some states require periodic review of the plugged well sites to confirm that a permanent seal is maintained.

4. Storage Well Operations

A. Well Integrity Evaluation (API 1171 Section 9)

Gas storage operators evaluate each individual well used for gas storage to determine its integrity and to ensure safe and environmentally responsible operations. Also included in the evaluation are third party wells that penetrate the storage reservoir and buffer zone or areas influenced by storage operations. As gas storage operators are not in control of third party wells, operators will have less information with which to assess the risks of such wells to storage operations.

Risk assessments are used as a basis for developing the integrity demonstration, verification, and monitoring tasks and for evaluating their frequency requirements. The operator's approach addresses the need for re-evaluation of risk-based conclusions, and the frequency of monitoring tasks.

Aspects of well integrity evaluation include the review of well design basis, drilling, completion and well workover records, wellhead inspections, casing inspections and other well logging, well pressure monitoring, and gas/fluid sampling. The outcome of these evaluations is a list of operating parameters for which operators specify bounds. Operators are putting in place monitoring systems to track the changes to these parameters with the goal of ensuring a well is always operated within its limits. Examples of parameters for which specific limits can be set include: wellhead injection and withdrawal pressures, tubing-casing annulus pressure if tubing is set on a packer, acceptable gas and fluid compositions, flow rate erosional velocity limits, operating temperatures, tubing and casing wall

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thicknesses, subsidence rates in the area of the storage reservoir, operating limits to prevent hydrate formation, and maximum gas inventory.

Well operating limits will be re-evaluated upon changes to well configuration and/or condition. If a well experiences conditions outside of these limits, operators investigate the cause, document the circumstances, and determine what actions are needed to continue to operate the well.

B. Well Integrity Demonstration, Verification & Monitoring (API 1171 Section 9.3)

Operators are guided in the development of measures needed to demonstrate, verify and monitor integrity of storage wells by risk assessment. Risk assessment is not a one-time event, but rather an on-going process. Some of the factors used when verifying and demonstrating well integrity include well service life history, well design, well construction, maximum and minimum operating pressures (for injection, withdrawal and well treating), the nature of the product stored, the nature of the fluids produced, down hole and atmospheric corrosion, casing and tubing condition, the condition, depth and height of wellbore cement, the need for and types of emergency shutdown valves (surface or subsurface), how each well is operated, and the time interval since the most recent assessment and past assessment findings. Because storage wells are not all the same, risk profiles will vary and the resulting measures may also vary from well to well. There are, however, basic elements of well integrity that are evaluated and monitored at some frequency, as determined by the well's risk profile.

Visits by operating personnel to storage well sites provide opportunities for data collection as well as observations of overall conditions at the well sites. Such information is an important part of the data set needed for the Step 1 of a risk assessment. Risk assessment determines the frequency of well site visits. The general condition of the site, including the access road, fencing (if present), signage and other above-ground appurtenances is assessed by visual inspection. Encroachment activities that could impact the integrity of the well or well site are also noted and reported immediately. Operators also inspect well site valves and fittings for visual and/or auditory leaks. The inspection includes monitoring of casing pressure changes at the wellhead. If operators choose to employ leak detection technology, selection and usage decisions include factors such as detection limits for natural gas or any liquids, response time, reproducibility, accuracy, distance from source, background lighting conditions, geography and meteorology. Leak detection technology continues to evolve and operators deploy such technology when it is appropriate to do so as part of the risk-based continual improvement process.

Operators function-test the wellhead master valve and wellhead pipeline isolation valve(s) at least annually, or more frequently as determined by the risk assessment. Testing provides assurance that the valves will function as required to shut in and isolate the well for operational or emergency purposes. These valves are maintained to the same standard as other isolation valves. When testing reveals deficiencies and a valve does not meet functional requirements, the valve is repaired or replaced promptly so the well's ability to control and isolate fluid flow is not compromised.

When risk assessment indicates that emergency shutdown valves are needed, function-testing of these valves is performed at least annually or more frequently as determined by the risk assessment. The tests are conducted according to the manufacturer's recommendations and the operator's procedures. If an emergency shutdown valve on a storage well closes, it is not reopened remotely, but instead the operator reopens it manually at the well site after investigation into the cause of the closure.

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Gas present in the annulus of wells can be, but is not always, an indication of loss of integrity. Storage operators collect and evaluate annular pressures and/or gas flow in cases where the outer annulus is left open. Annular pressure thresholds are determined (where not defined by regulation) from well integrity evaluation and risk assessment. The evaluation accounts for depth of casing strings on each side of the annulus, characterization of the annulus contents, pressure ratings of the casing strings and formation fluid pressures outside the casing strings. When annular pressure is detected, wellhead leaks can be eliminated or confirmed as the source of the annular gas by testing the wellhead seals where injectable packing and/or test ports are present. In some cases, annular gas can be sampled and analyzed to help determine the origin, since annular gas can occur from sources other than the gas storage reservoir.

Monitoring for defects, degradation, and corrosive and mechanical wear of tubular goods (casing, tubing or tubing/casing annulus) and evaluating the impact on well integrity is an on-going process. The frequency of monitoring is decided as part of the well integrity management plan and the underlying risk assessment that provides the basis for the integrity management plan. Tubular monitoring addresses:

- Evaluation of the integrity of the tubular goods and the identification of corrosion defects and other chemical/mechanical damage
- Corrosion potential of produced wellbore fluids and solids, including the impact of operating pressure and the analysis of partial pressures
- Corrosion potential of annular/packer fluid
- Corrosion potential of current flows associated with cathodic protection systems if applied to the well casing
- Corrosion potential of all formation fluids including fluids in formations above the storage zone
- Corrosion potential of un-cemented casing annuli including static liquid levels
- Corrosion potential of adverse current flows associated with cathodic protection systems from nearby pipelines and other production facilities

There are numerous methods used to monitor downhole conditions, including corrosion, and operators evaluate which methods to employ based on well configuration and risk assessment. Evaluation of well information, hazards and threats and the likelihood and consequence of failure drive decisions regarding tool usage and frequency of deployment for monitoring downhole conditions. When operators remove tubular goods during workovers and corrosion products are visible, samples can be sent for metallurgical analysis to help determine the cause and mechanisms of the corrosion. Some of the other tools used to evaluate downhole conditions (including corrosion) in tubing and/or casing include:

- Temperature, differential temperature and/or noise logs to look for anomalous readings that could indicate fluid movement behind pipe
- Neutron logs to look for accumulations of gas in formations outside the storage zone(s)

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- Eddy-current/magnetic flux leakage logs to help determine inner and outer wall metal loss and pipe defects
- Caliper logs to evaluate inside diameter, internal corrosion and defects
- Cement bond logs to help determine cement tops and bond quality to the casing and to the formation
- Segmented bond logs to look for cement channeling
- Downhole cameras for visual inspection of the inside of the casing or tubing
- Ultrasonic imaging logs to help determine cement channeling, internal diameter, wall thickness, pipe eccentricity and defects
- Electromagnetic casing potential logs to help identify axial and radial current density, corrosion rate, external corrosion location and casing thickness

These specialized tools require specific wellbore conditions and technicians to run them and to evaluate the results. Different tools evaluate different properties of metal, fluids or voids, including anomalous readings, gas behind pipe, fluid movement, corrosion potential, metal loss (wall thinning, pits) and other defects (split pipe, ovalities, kinks, holes). Operators determine which (if any) of these tools are appropriate to use as a means of gathering data to aid in the assessment of the as-current health of key components of the well barrier envelope. These data can be part of a risk reduction program when increased or additional monitoring is indicated.

When new wells are drilled, baseline logs are run to aid in future well integrity monitoring, including logs that evaluate changes in gas located behind casing (for example neutron logs) and the condition of newly installed casing (for example magnetic flux leakage or acoustic-type casing inspection logs). Baseline logs help determine anomalies present when the pipe is first installed, and since new installed wells are tested for mechanical integrity prior to being placed in service, the presence of these same anomalies on future logs can be explained. Future log runs are useful to follow the progress of any anomalies detected and, with the aid of risk assessment, they can help operators determine when mitigative steps are needed.

Risk assessment is holistic, in that all threats to the integrity of the gas storage facility are evaluated. In addition to wellhead and wellbore mechanical damage and corrosion, operators evaluate the effects of flow erosion, hydrate forming potential, facility component flow capacity and corrosive potential of fluids present across the gas flow rate and pressure operating envelope for the facility.

Operators use the monitoring of well pressure (including shut in wells) as a means of demonstrating on-going well integrity. Unanticipated changes to historical trends are investigated and findings and corrective actions are noted for future reference. Many times these changes are operational issues (such as faulty instrumentation) and explainable, but these anomalies deserve careful evaluation since they can also be early warnings of potential loss of well integrity.

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C. Well Barriers and Potential Leak Paths (API 1171 Section 9.3)

Operators have designed and installed a number of different well completions depending on their historical experiences, practices, and site-specific conditions. A common well completion case referenced herein contains production casing without tubing. The primary root cause mechanisms for storage gas well releases for this completion are 1) wellhead component or seal failure; 2) production casing leak; or 3) a downhole annular barrier breach (i.e. cement sheath). These primary leak paths are depicted on the schematic in Appendix 5 Gas Storage Well Configuration: Example C and described more fully below:

1) Wellhead component or seal failure

This leak path occurs when the primary and secondary seals in the wellhead fail, allowing gas in the production casing to migrate past the seals into the production casing annulus. Leaks can also occur as a result of mechanical failure of other wellhead components such as casing slips, which can allow the production casing to drop free of the wellhead seal assembly. Observations that indicate a potential leak may exist include an increase in annular pressure or flow, dependent on the annular valve position during normal well operation mode.

For a release to occur, an initial failure takes place allowing pressurized storage gas to leave the production casing. Gas then either exits through an open annular valve or pressures up the annulus, if closed. To eliminate this type of release to the atmosphere, some operators close the annular valve while the well is in operational mode. However, if pressurized gas is trapped in the annulus and not allowed to dissipate, there is a possibility of additional secondary failures that will lead to more complex, and difficult to control, release paths, hence other operators leave the annular valves open in normal operational mode.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations; test wellhead seals, observe wellhead components for indications of leakage (noise and/or hydrate deposition), and/or perform interference testing between the production casing and production casing annulus to determine if the leak is at the surface or downhole. Leak resolution may include replacing the wellhead assembly or wellhead seals and/or repair or partial replacement of the production casing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

2) Production casing leak

This leak path occurs when the production casing wall is breached. Causes include but are not limited to production casing failure due to reduced casing wall thickness from corrosion and/or the introduction of higher pressures than containable for stimulation treatments, or production casing wall collapse from outside forces such as earth movement or foreign production operations. Observations that indicate a potential leak may exist are lower than expected shut-in pressures or gas exiting somewhere outside of the structure of the wellbore.

The stored gas can escape outside the structure of the storage wellbore from deep underground and migrate through a path of least resistance upward until it reaches an alternative escape path. The escape path could be through an oil and gas, water, or abandoned well completed in a shallower permeable formation or the path could be all the way to an escape at the surface. Operators must understand subsurface geologic conditions to assess the risk of geologic migration.

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Diagnosing the failure mechanism requires the operator to perform one or more of the following operations: obtain electric logs (pipe inspection, caliper, gamma ray-neutron, differential temperature, noise, spinner flow survey, etc.); install a bridge plug and pressure test the casing. Options for the operator to resolve the breach may include partially replacing the production casing, installing a casing internal patch, cladding, or liner, and/or remedial cementing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

3) Downhole annular barrier breach

This leak path occurs when gas and/or hydrostatic pressure in the annulus exceeds the strength of the rock below the intermediate or surface casing shoe, resulting in establishment of an escape path outside the wellbore. Observations that a potential leak may exist are gas exiting somewhere beyond the structure of the wellbore.

In this case storage gas finds a path of least resistance around the intermediate casing shoe and then into the subsurface lithology where it could enter an oil and gas, water, or abandoned well completed in a shallower permeable formation, or migrate all the way to an escape at the surface.

Diagnosing the failure mechanism requires the operator to obtain electric logs (gamma ray-neutron, differential temperature, ultrasonic/noise, etc.) as needed to determine the direct cause. In order to resolve this breach, the operators will usually require remedial cementing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

Note: for any gas release path scenario, failure of one or more barriers to storage gas containment must occur. Proactive wellbore integrity inspections and annular barrier monitoring and evaluations that result from a site-specific risk assessment model are key elements to identifying and resolving a direct failure mechanism before it occurs.

D. Site security, inspections and emergency response (API 1171 Section 10)

Storage operators assess and monitor the security and safety of their well sites and have an emergency plan in place in the unlikely chance of an event. The overall goal of the plan is to reduce the potential for an incident and to ensure the safety of the public, operating personnel, contractors, property and the environment. Thorough preparation and training enables operating personnel to recognize and respond to abnormal operating conditions or to changes in site security in a timely manner so as to minimize or prevent impacts.

Due to the variety of designs for downhole and wellhead facilities, the potential failure modes of a well can be different from well to well even in the same field. Likewise, utilization of adjacent lands by the surface owner and wellsite configuration also add diversity. Therefore, the safety and security plan are site-specific and are determined by the operator's risk assessment.

Operators take additional steps to maintain site security and safety by limiting access during drilling, workover, wireline logging and other similar activities. Additionally, operators can use fencing, barricades and other barriers to restrict access during on-going operations as determined through their site-specific assessments. The implemented security and safety measures are influenced by the well's flow potential, location, population density, natural forces, terrain and environment adjacent to the

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wellsite. Operators are aware of potential ignition sources on the wellsite during well work and locate such potential ignition sources in a manner that provides for on-going safety.

Site inspections to review the safety and security of storage facilities at the well site are performed on a regular and periodic basis. Inspections are often concurrent with the collection of well data, such as annular pressures, mechanical integrity inspections, or other operational activities such as opening or closing the well. Changes in the status or condition of an item being utilized in the risk analysis are reported to the storage personnel responsible for the risk analysis process. This change will then be utilized in the next iteration of the risk analysis and the operator will implement new, additional and/or different risk preventive and mitigative measures, if necessary.

To ensure consistency and the collection of accurate information, operators are developing forms listing the inspection criteria and training personnel in how to conduct the inspection. The inspection results are saved according to the operator's document retention policy.

Operators are developing, implementing and updating emergency preparedness/response plans that cover accidental releases, equipment failures, natural disasters and third party damages. Gas storage plans are incorporated into the operator's existing emergency procedures for the pipeline system and include personnel roles and responsibilities, emergency contact information, communication protocol, procedures for response to leaks, fires and uncontrolled well releases and other information and tasks as further detailed in API 1171. Operators are training personnel using the emergency response plan. Often, operators contact local emergency responders and discuss incident scenarios and potential response alternatives.

A key component of an underground storage operator's emergency response plan that is unique to well operations is a well emergency plan which treats loss of containment or loss of control incidents occurring during well drilling, servicing or operating. Due to the potential wide variety of well emergencies, the operator's plan needs to be flexible. The plan identifies the procedures, equipment and personnel needed to respond to the situation.

E. Procedures and training (API 1171 Section 11)

Operators are updating existing and developing new processes and procedures to identify and address the safe operation, maintenance and inspection of storage wells, consistent with requirements, safety policies, regulations and applicable standards. The authors have existing safety processes and procedures established to conform with basic well safety established by state regulatory authorities or the operator's prudent practices.

As stated previously, gas storage operators are in various stages of establishing conformance with API 1171 guidance. Operators are conducting gap analyses between their current practices and API 1171 with respect to procedures and training. Closing the identified gaps to align with API 1171 is part of the process expected to be performed within the 7-10 years following a final rulemaking.

Procedures address all operations phases, including:

- Initial startup (new, modified, or acquired facilities)
- Normal operations
- Temporary operations as needs arise

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- Normal shutdowns
- Emergency operations, including emergency shutdowns
- Start-up or restoration of operations following maintenance

Procedures are put in place prior to the development of a new storage facility, and address the minimum requirements for construction including drilling and other well entry work, reservoir integrity monitoring and management, operations and maintenance, emergency response, control room communications and responses, personnel safety, safety management systems, and site-specific procedures determined to be necessary by the operator.

Operators are training personnel responsible for operating, maintaining, and monitoring storage wells and reservoirs in accordance with their duties and responsibilities. Training addresses operating procedures, safety procedures, recognition of abnormal operating conditions and emergency conditions. Training programs can consist of methodologies including, but not limited to classroom, computer-based and on-the-job training. Operators review training programs periodically to determine effectiveness. Training programs are modified when changes occur in technology, processes, procedures, or facilities. Operators evaluate the effectiveness of training to verify that persons assigned to operate and maintain storage wells and reservoirs possess the knowledge, skills, and abilities necessary to carry out their duties and responsibilities including those required for start-up, operation and shutdown of storage facilities. Personnel are trained on the site-specific procedures necessary for operation of storage wells and reservoirs, as well as trained on the recognition of abnormal operating conditions. Reporting requirements, documentation, and recordkeeping requirements are included in the training.

Integrity Management programs also integrate storage well and reservoir elements so that procedures and programs work together to promote the integrity of the storage facility. Data required include geologic information on the formations penetrated by the storage well, wellbore configuration and completion data (e.g. casing characteristics, setting depths, cement, etc.), pressure and volume data on the flow capability of the well and reservoir, annular pressure and/or volume data, reservoir fluid analysis, wellhead design, and other characteristics of the subsurface in addition to information about the wellsite.

Operators establish regular review frequencies for the procedures and use management of change to provide for orderly review and acknowledgement of changes and the impacts to integrity and safety. Procedures are modified to account for changes in operating conditions, advancements in technology, regulatory changes, abnormal operating conditions, or as experience dictates.

Operators retain the records necessary to administer the procedures and establish retention requirements for specific records. Whenever changes are made to the operating procedures, operating personnel are notified and trained as necessary and the training is documented. Records management includes requirements for identification, collection, storage, protection, retrieval, retention time and disposition of records.

Operators maintain records of well configuration (as-built), well construction and well work activities for the life of the facility. These records include, as applicable and available:

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- Wellhead equipment and valves
- Well casing
- Casing cementing practices
- Completion and stimulation
- Monitoring of construction activities
- Testing and commissioning
- Well remediation
- Well closure

Operators use pipeline public awareness and damage prevention communications that include information regarding the utilization of damage prevention notification systems, education of the public on the hazards related to unintended releases, indications of a release, procedures for reporting the release and actions to be taken for public safety during the release.

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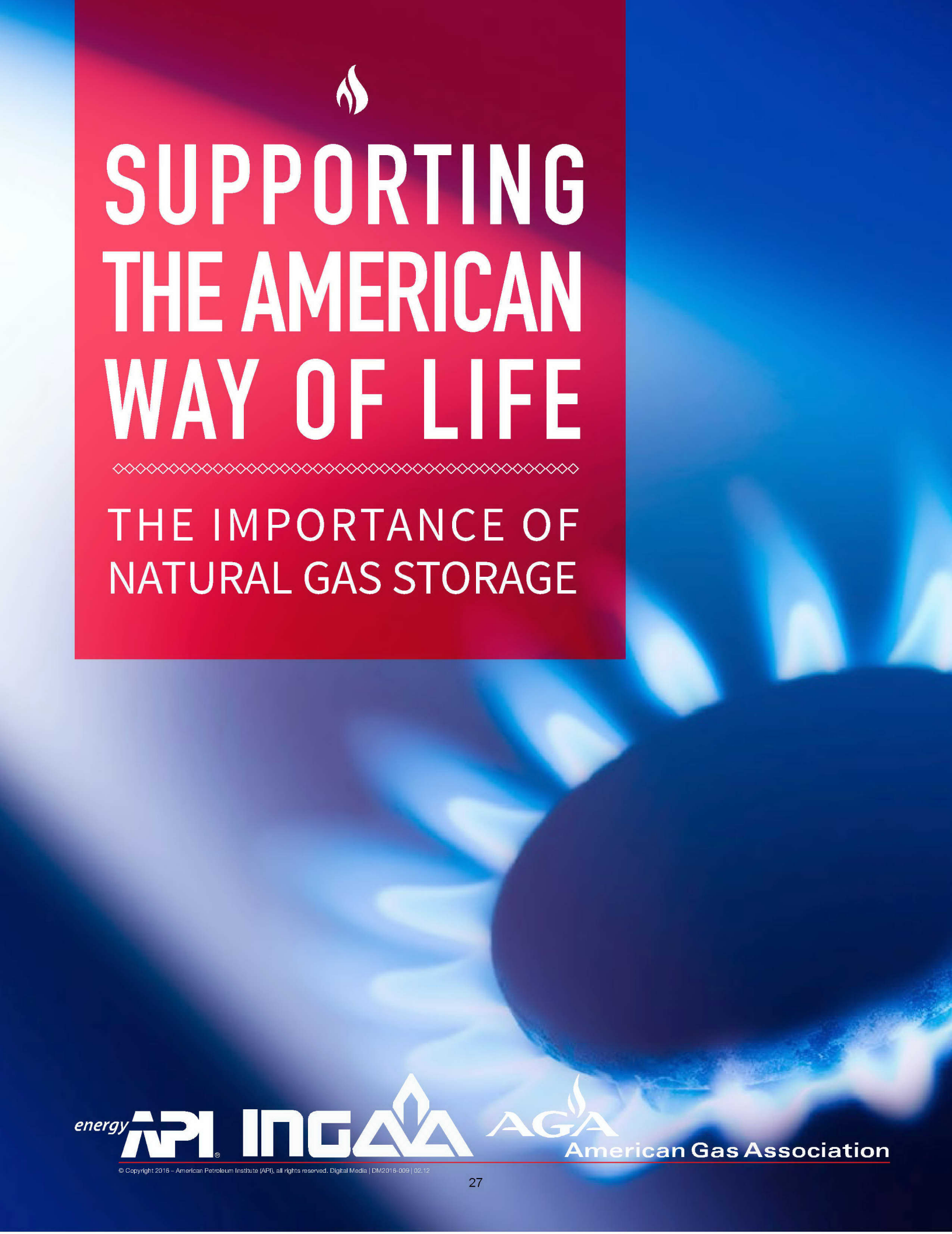
Appendix 1

Background - Underground Storage of Natural Gas in the U.S.



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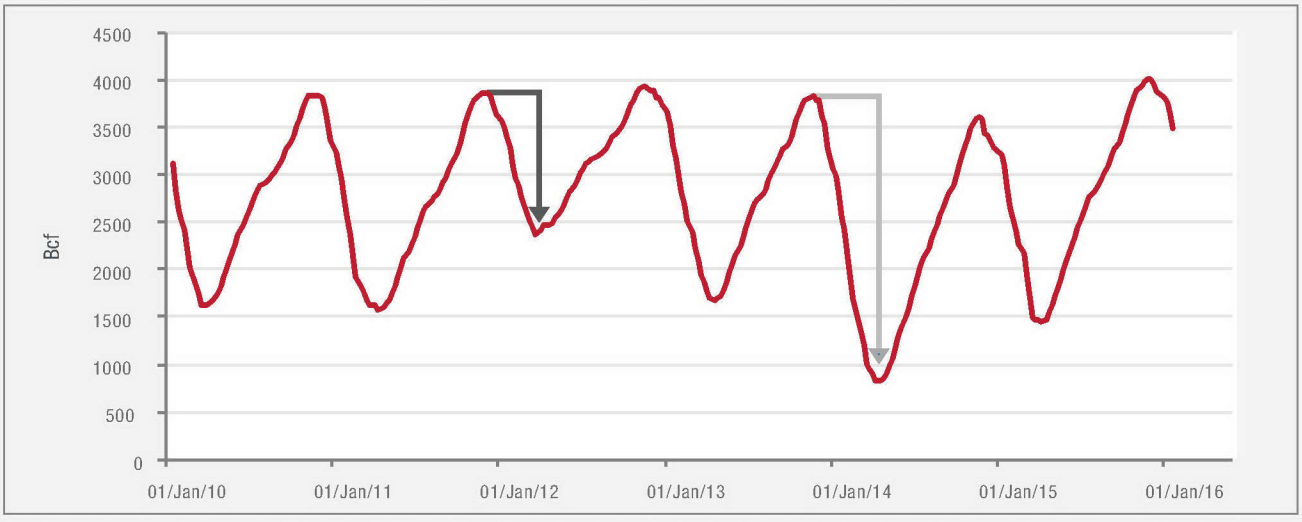
WHERE NATURAL GAS STORAGE IS LOCATED?

Underground storage of natural gas is an integral component of the nation's energy system, and our nation's significant storage capacity enables utilities to offer clean natural gas to consumers throughout the year with reliable service and prices.[1]

This use results in significant seasonal variations in which natural gas consumption is highest during the winter time and lowest during mild-weather months. Natural gas storage enables supply to match demand on any given day throughout the year.

Natural Gas Working Storage Levels

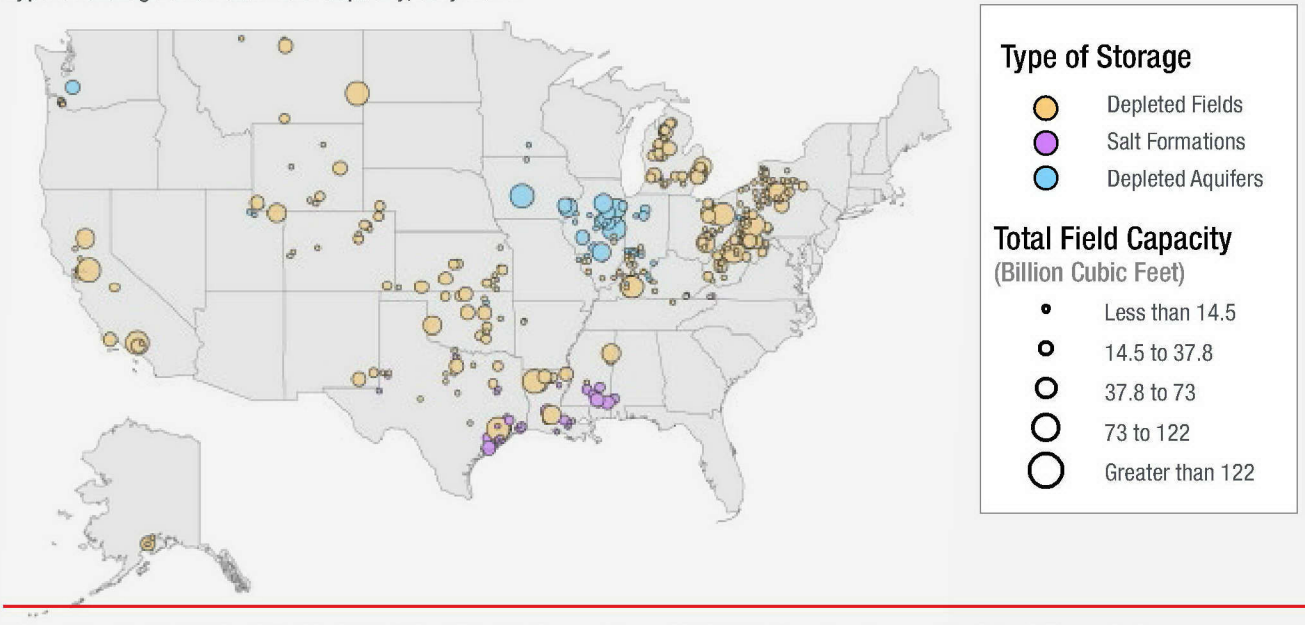
Energy Information Administration, "Weekly Natural Gas Storage Report, History," January 8, 2016.



The chart above shows how storage fluctuates with the weather. During the mild winter of 2012, the gas withdrawn from storage was far more moderate (see black arrow). In contrast, in 2014, the year of the Polar Vortex, natural gas storage was "drawn down" sharply (see grey arrow). But even in the mildest of winters, such as 2012, natural gas withdrawals from storage were vital to meeting winter natural gas demand.

Where Natural Gas Underground Storage Fields are Located

Type of Storage and Total Field Capacity, July 2014



[1] Energy Information Administration, "Natural Gas Explained, Use of Natural Gas," accessed January 15, 2016, http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_use

NOTE: that the map includes both active and inactive fields.

SOURCE: EIA Energy Mapping System; EIA-191 Monthly Underground Gas Storage Report July 2014

HOW IS NATURAL GAS STORED?

How is Natural Gas Stored?

Natural gas is stored underground primarily in three reservoir types: depleted oil and gas fields, depleted aquifers, and in salt beds and salt caverns. Natural gas may also be stored above ground in refrigerated tanks, as liquefied natural gas (LNG).

Types of Natural Gas Underground Storage

Depleted Natural Gas or Oil Fields

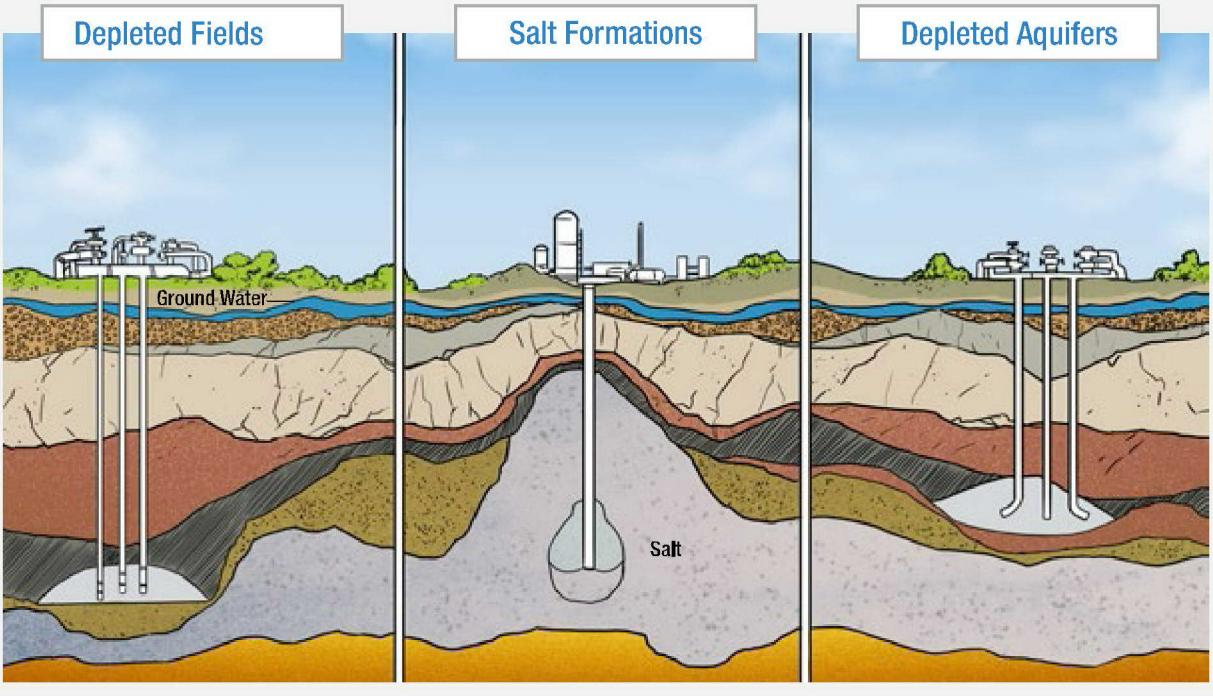
Of the approximately 400 active underground storage facilities in the U.S., about 79 percent are depleted natural gas or oil fields. Conversion of an oil or gas field from production to storage takes advantage of existing infrastructure such as wells, gathering systems, and pipeline connections. Depleted oil and gas reservoirs are the most commonly used underground storage sites because of their relatively wide availability.

Salt Formations

Salt formation storage facilities (also known as salt caverns or salt beds) make up about 10 percent of all facilities. These subsurface salt formations are primarily located in the Gulf Coast states. Salt formations provide very high withdrawal and injection rates.

Depleted Aquifers

Natural aquifers may be suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. They are not part of drinking water aquifers and make up only about 10 percent of storage facilities.



SAFETY IN UNDERGROUND STORAGE OF NATURAL GAS

Underground natural gas storage operators are committed to ensuring the safety and integrity of their facilities. The industry's construction, operation and integrity management protocols are overseen by multiple agencies at the state and federal level with jurisdiction over underground storage facilities:

- The Federal Energy Regulatory Commission (FERC) regulates projects connected to interstate pipeline systems. FERC is responsible for authorizing the construction or expansion of storage facilities and the terms and conditions of service (i.e., open access) and the rates charged by these providers.
- The Pipeline and Hazardous Materials Safety Administration (PHMSA) is authorized to regulate the safety of natural gas transportation and storage.
- Intrastate storage may fall under the regulatory authority of various state government entities depending upon the state. For example, underground storage in Texas is under the authority of the TX Railroad Commission – Oil & Gas Division. Often state utility commissions as well as state environmental or natural resource agencies set the rules governing intrastate underground storage.

Beyond federal and state regulation, industry has taken the initiative to work with external stakeholders to develop two recommended practices (RPs)—accredited by the American National Standards Institute—for underground storage. RP 1170 and 1171 provide guidance to operators on how to design, operate, and ensure the integrity of underground storage for natural gas.

Underground Storage by the Numbers

- Approximately 400 active storage facilities in 30 states, made up of depleted natural gas or oil fields (80%), depleted aquifers (10%) and salt caverns (10%)
- Approximately 20% of all natural gas consumed during the winter is supplied by underground storage
- Underground storage capacity increased 18.2% between 2002 and 2014
- Approximately 4 trillion cubic feet of natural gas can be stored underground, or enough to meet an average states residential natural gas consumption for more than 20 years

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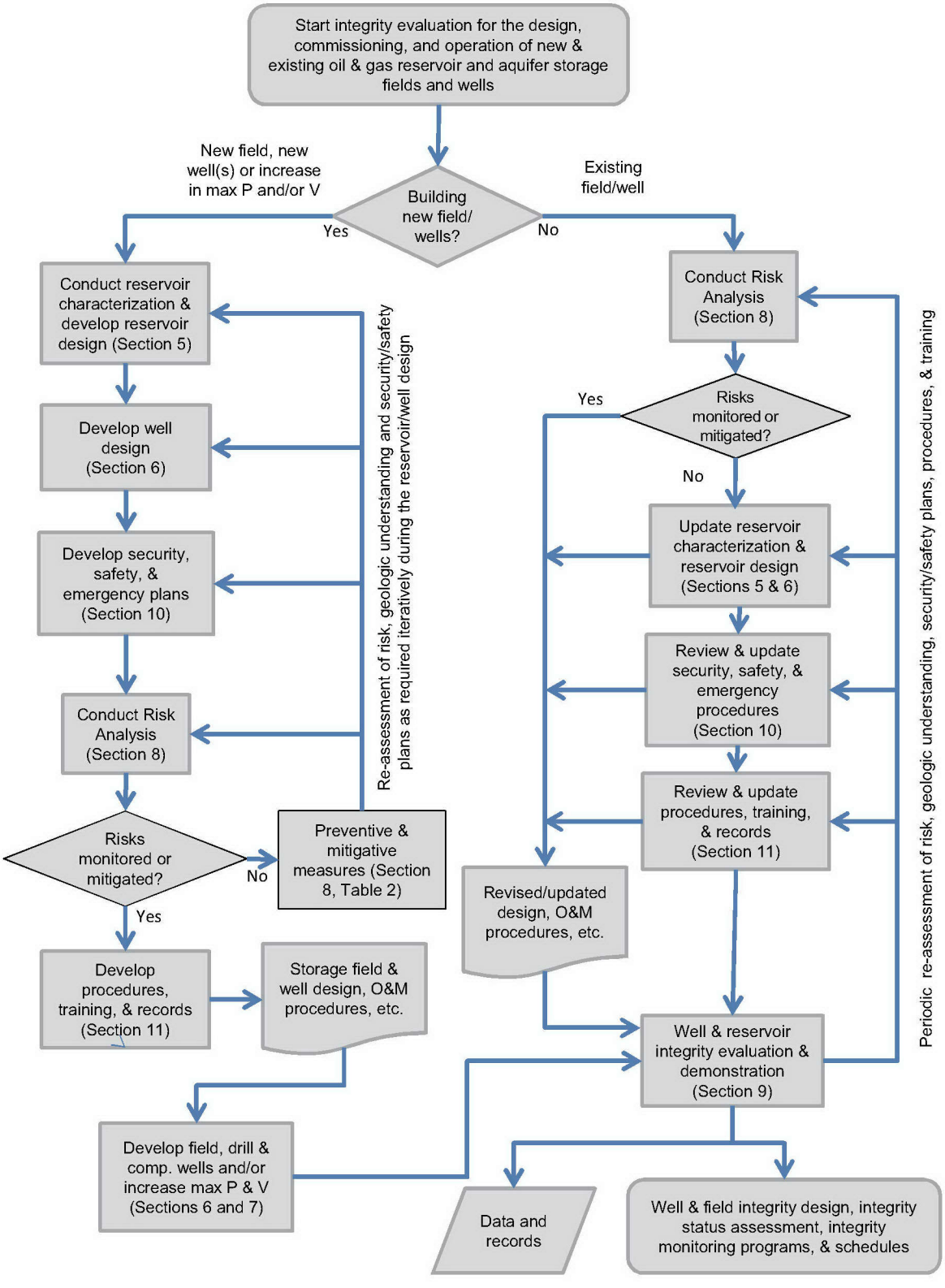
Appendix 2
Various Steps for Well & Reservoir Integrity Management Evaluation

Source: API Recommended Practice 1171, Figure 1



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Appendix 3
Storage Well Potential Threats and Consequences

Source: adapted from API Recommended Practice 1171, Table 1

Threat or Hazard	Threat/Hazard Description	Potential Consequences
Well integrity (corrosion, material defect, erosion, equipment failure, annular flow)	Gas containment failure due to inadequately sealed storage well(s), e.g. casing corrosion, cement bond failure, material defect, valve failure, gasket failure, thread leaks, etc.	• Loss of stored gas inventory • Damage to well site facilities and equipment • Safety hazard to company personnel and the public • Loss of use of water sources and/or wells • Decrease or loss of field performance
Design	Gas containment failure due to inadequate completed wells, sealed plugged well(s), failure of cement squeeze job perforations or stage tool, pressure rating of components, etc.	• Release of gas to the atmosphere • Damage to well site facilities and equipment • Safety hazard to company personnel and the public • Loss of use of water sources and/or wells • Loss of stored gas inventory • Decrease or loss of field performance
Operation and maintenance activities	• Inadequate procedures • Failure to follow procedures • Inadequate training • Inexperienced personnel and/or supervision	• Loss of stored gas inventory • Damage to well site facilities and equipment • Safety hazard to company personnel and the public • Loss of use of water sources and/or wells • Decrease or loss of field performance
Well intervention	Gas containment failure due to loss of control of a storage well while drilling, reconditioning, stimulation, logging, working on downhole safety valves, etc.	• Damage to drilling rig or service rig • Loss of tools in wellbore • Hazard to operator and service company personnel • Safety hazard to public • Decrease or loss of field performance • Loss of well
Third party damage (intentional/ unintentional damage)	Intentional/ unintentional damage	• Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities: ○ Loss of ancillary facilities ○ Well on/off status change ○ Impact to service reliability ○ Impact to neighboring public, storage gas loss
Outside force-natural causes	Weather related and ground movement	• Heavy rains, floods, lightning, earth movements, groundwater table changes, subsidence, etc. that could result in: ○ Damage to facilities/impact to service reliability

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Appendix 4
Storage Well Preventive and Mitigative Programs

Source: adapted from API Recommended Practice 1171, Table 2

Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs
Well integrity (corrosion, material defect, erosion, equipment failure, annular flow)	• Casing condition and inspection program • Monitoring pressure, rate and inventory • Cement analysis and evaluation • Internal corrosion monitoring • Plugged and abandoned well review and surveillance • Monitor annular pressures, rates, or temperatures • Subsurface and surface shutdown valves • Monitor cathodic protection as applicable • Operate, maintain and inspect valves and other components
Design	• Collect and evaluate plugged and abandoned well records and rework or plug • Develop design standards for new wells • Evaluate current completion of existing wells for functional integrity and determine if remediation monitoring is required
Operation and maintenance activities	• Procedures • Training of personnel and contractors and establishment of procedures
Well intervention	• Implement training and safety programs for company and contractor personnel • Develop detailed drilling and well servicing procedures

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Appendix 5

Well Configuration Examples A, B, and C

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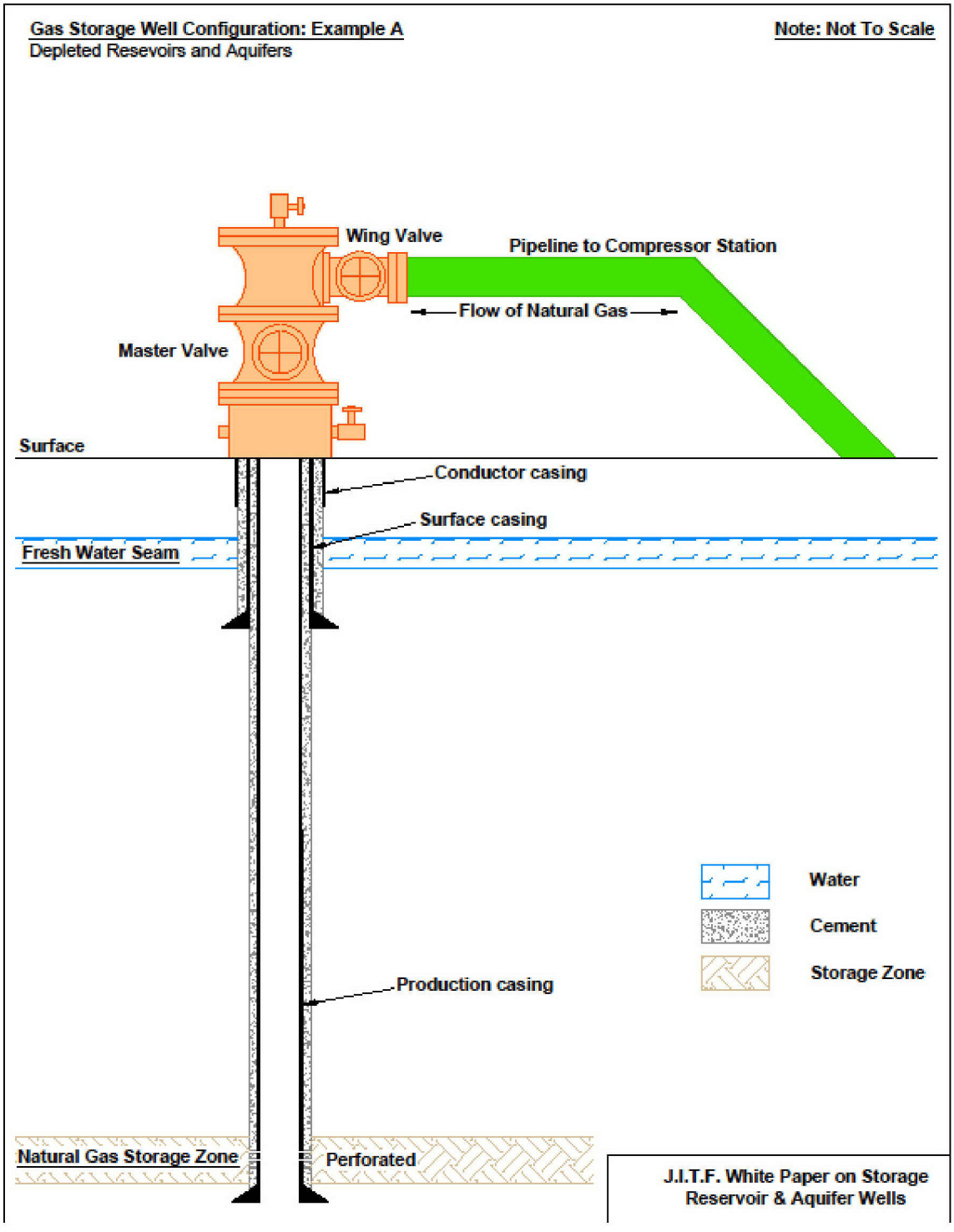
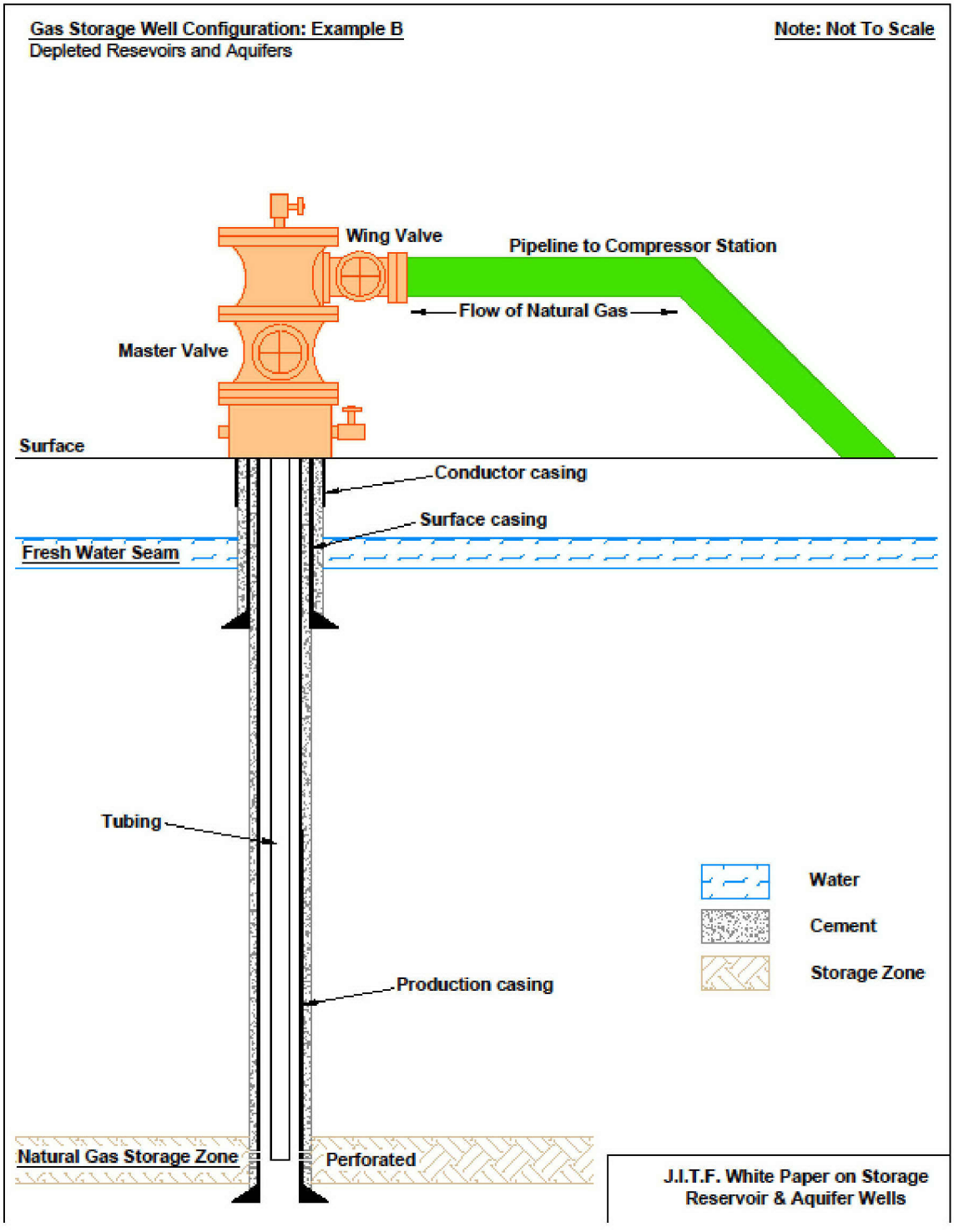
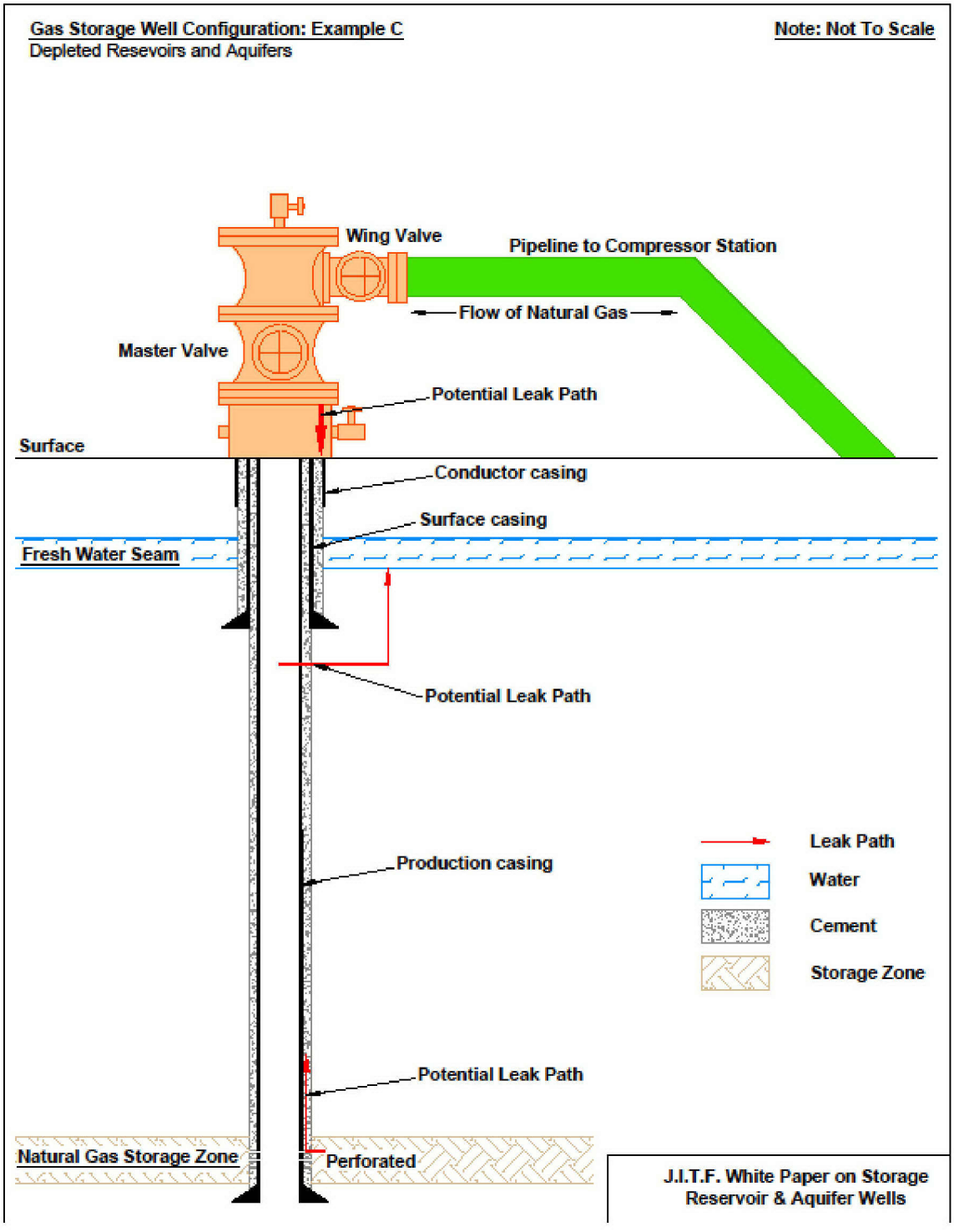

Gas Storage Well Configuration: Example A
Depleted Resevoirs and Aquifers
Note: Not To Scale
Wing Valve
Pipeline to Compressor Station
Flow of Natural Gas
Master Valve
Surface
Conductor casing
Surface casing
Fresh Water Seam
Water
Cement
Storage Zone
Production casing
Natural Gas Storage Zone
Perforated
J.I.T.F. White Paper on Storage Reservoir & Aquifer Wells


Gas Storage Well Configuration: Example B
Depleted Resevoirs and Aquifers
Note: Not To Scale
Wing Valve
Pipeline to Compressor Station
Flow of Natural Gas
Master Valve
Surface
Conductor casing
Surface casing
Fresh Water Seam
Tubing
Production casing
Water
Cement
Storage Zone
Natural Gas Storage Zone
Perforated
J.I.T.F. White Paper on Storage Reservoir & Aquifer Wells


Gas Storage Well Configuration: Example C
Depleted Resevoirs and Aquifers
Note: Not To Scale
Wing Valve
Pipeline to Compressor Station
Flow of Natural Gas
Master Valve
Potential Leak Path
Surface
Conductor casing
Surface casing
Fresh Water Seam
Potential Leak Path
Production casing
Leak Path
Water
Cement
Storage Zone
Potential Leak Path
Natural Gas Storage Zone
Perforated
J.I.T.F. White Paper on Storage Reservoir & Aquifer Wells

Appendix 6

Emergency Shutdown Valve Systems in Natural Gas Storage Wells: Application, Historical Use and Reliability, and Risk Assessment for Decision-Making in Regard to Application

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Executive Summary

This Appendix explains Emergency Shutdown Valve (ESV) systems, their use and application in natural gas storage, operating experience and reliability, standards and regulations, and risk assessment related to decision-making on ESV application. ESVs can be installed above ground as Surface Safety Valves (SSV) or below ground as Subsurface Safety Valves (SSSV). Above ground systems are much easier to assess, test, and maintain, but their ability to provide physical barrier control can be limited if the wellhead becomes damaged. Underground valves can sense abnormal surface conditions and close, but are more difficult to operate and, in the experience of this Joint Industry Task Force (JITF) team, have additional issues that affect reliability and safety. Based on industry surveys, this team estimates that approximately three to five percent of storage wells currently have SSSVs. This Appendix explains ESV systems, summarizes some available reliability information, summarizes the benefits and reliability issues experienced by storage operators, and provides storage operator industry perspective. Appendices provide company operating experience testimonials, literature reviews of ESV reliability and risk management guidance.

Natural gas storage operators have consistently provided safe and reliable natural gas storage. As natural gas storage is critical for meeting peak hourly, daily and seasonal user demand for natural gas, natural gas storage operators are continually searching for new equipment, processes, and methodologies to improve safety and reliability. ESVs have a long operating history in natural gas storage fields. Gas storage operators have employed SSSVs since the 1960s and 1970s. SSSV use increased in the 1980s and 1990s in production and storage settings. Natural gas storage operators began installing SSSVs within their storage wells to act as a physical control barrier, activating during pressure, temperature, or surface damage events. Several companies within the natural gas storage industry embraced SSSVs to provide an additional barrier control for high risk storage wells. Operators began installing SSSVs at locations of concern such as roadways or near homes to provide an additional level of safety in case a breach at the wellhead occurred. In the period since their first installations, storage operators have gained experience with operating and maintaining SSSVs, have a better understanding of their safety benefits, and have learned the additional reliability challenges and risks that come with their application.

The benefits of ESV systems include risk reduction related to consequence mitigation by limiting the magnitude and duration of an event that occurs downstream of the valve. The ESV system provides a means of automatic or controllable shut-off of flow and thus could have a protective effect to places of habitation, roads, human gathering places, environmentally sensitive areas, other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. The fail-safe, automatic or controllable functionality of ESV systems protect against uncertain events such as natural forces (earth movements, seismic activity, floods, severe weather events and other earth forces) or human-induced activity that could have adverse impact on well integrity. ESV system technology is a proven technology that has been extended to wider applications in terms of depth, location, diameter and pressure-temperature-flow regimes.

In the period since the 1960s, natural gas storage operators have observed a variety of challenges associated with ESV system use in the subsurface (SSSV), including the impairment of storage service reliability, increased risks to field operators (workers) and the public due to increased well re-entry (service) rates and related loss-of-containment potential, and increased challenges with emergency intervention operations. SSSV do not arrest all leaks, only those severe enough to activate the valve. A

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shallow SSSV installation does not shut-down the flow of gas through a deep casing breach or other event upstream of the valve. Shallow SSSVs are designed to limit the amount of escaping gas in a catastrophic surface or near-surface event. SSSVs might not seal gas tight over time because the conditions in which they operate are harsh in terms of exposure to high velocity, large pressure variations, liquids, sand and other particulates.

Key observations discussed in this Appendix include:

1) ESV systems are a physical control, or barrier, requiring a specific set of conditions in order to activate.
2) An ESV system, if functioning properly during the specific event for which it was designed, can reduce the consequences of an event by minimizing duration and impact.
3) ESV system valve setting (location in the well) determines the risk reduction benefit for a particular event.
4) ESV in the downhole well environment have reliability and safety issues:
    a. Reliability rates (Mean Time to Failure (MTTF), Mean Time to Repair (MTTR)) have well-established ranges for immediate service impacts (corrective maintenance) as well as longer-term functional failures requiring well re-entry and repair or replacement (based on industry literature review and storage operator testimony).
    b. SSSVs can have service reliability impairment due to tubing string/ valve flow diameter restrictions along some length of the wellbore (storage operator testimony).

Table 1. Probability Descriptors per the Center for Chemical Process Safety (CCPS) American Institute of Chemical Engineers (AIChE)

Descriptor	Decimal Notation			Scientific Notation		
	(Incidents per well-year)			(Incidents per well-year)		
Likely	> 0.01			> 1.0E-02		
Unlikely	0.001	to	0.0099	1.0E-03	to	9.9E-03
Very Unlikely	0.00001	to	0.00099	1.0E-05	to	9.9E-04
Extremely Unlikely to Remote	< 0.00001			< 1.0E-05		

5) SSSVs can mitigate the impact of a casing or casing/cement system loss-of-control/loss of containment event. The frequency of these events - as established in industry literature for the broader applications in the oil and gas exploration and production industry - is "very unlikely" (The Center for Chemical Process Safety defines "very unlikely" as in the range 1E-05 to 0.99E-04 per well-year – Table 1). Natural gas storage well casing failure and cement failure rates are in the "very unlikely" range of E-05 per well-year. Wells with two or more passive physical barriers (such as a casing string and a full cement sheath, etc.) have failure rates at least one order of magnitude less than a single technical barrier system, AND have inherent reliability if there is no degradation of these barriers by time-dependent decay modes such as corrosion. Failure rates quoted here are from industry surveys and literature sources referenced in this Appendix, including published papers from the Society of Petroleum Engineers, and the March 2005 report to the Gas Research Institute under Contract No. 8604, Project No. 809833, "Risk Assessment Methodology For Accidental Natural Gas and Highly Volatile Liquid Releases From Underground

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Storage, Near-Well Equipment," prepared by Glenn DeWolf, Katherine Searcy, Douglas Orr and Christopher Loughran on behalf of URS Corporation.

6) Wells with an SSSV can provide the entire well system with a failure rate of up to one order of magnitude less than that for a well system with only one physical passive barrier; however, SSSV have reliability weaknesses which increase the number of well re-entries and erode the risk reduction benefit by service impairment, service reliability impairment, and increased risk of loss of containment and increase the risk of worker safety due to well re-entry for servicing, repairing, or replacing the SSSV. The information to support the conclusion is from storage operator testimony, industry literature, and the Gas Research Institute report noted in conclusion #5.

Conclusions and Recommendations

Based on the operational knowledge of those assisting in the creation of this Appendix, and the research conducted by this team, there are advantages and disadvantages associated with SSSV.

The benefits include risk reduction related to consequence mitigation by limiting the magnitude and duration of an event that occurs downstream of the valve. The ESV system provides a means of automatic or controllable shut-off of flow and thus could have a protective effect to places of habitation, roads, human gathering places, environmentally sensitive areas, other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. The fail-safe, automatic or controllable functionality of ESV systems protects in particular against uncertain events such as natural forces (earth movements, seismic activity, floods, severe weather events, and other earth forces) or human-induced activity that could have adverse impact on well integrity. ESV system technology is a proven technology that has been extended to wider applications in terms of depth, location, diameter and pressure-temperature-flow regimes.

The disadvantages of ESV systems, particularly SSSVs, include functional reliability weaknesses for components of ESV systems, potential impairment of storage service reliability, increased risk to workers and the public due to increased well re-entry (service) rates and related loss-of-containment potential, and increased challenges with emergency intervention operations.

Therefore, it is recommended that the natural gas storage industry support, develop, and implement risk-based integrity management plans to mitigate risks, reduce potential adverse impacts, consider ways to mitigate the consequences of a casing or casing/cement system loss-of-control/loss of containment event, while balancing potential unintended consequences related to the application of equipment like ESVs, SSVs, and SSSVs. Government and industry are already taking steps to implement risk based Integrity Management plans for natural gas underground storage.

The authors align with the recommendations made in PHMSA's Storage Advisory in Docket No. PHMSA – 2016-0016" with respect to decision-making around the use of ESV or alternatives. Specifically, the PHMSA advisory bullet #4 recommends periodic function tests for all ESV systems and the repair of deficiencies and failures, or the removal of the well from service, or employment of alternative and equivalently effective safety measures. PHMSA advisory bullet #5 recommends that operators evaluate the need for subsurface safety valves on new, removed, or replaced tubing strings or production casing using risk assessment aligning to API 1171 criteria as a minimum, and that where subsurface safety valves are not installed, the operator use the risk assessment to inform decisions on integrity inspection frequencies, reassessment intervals, and well integrity issue or incident mitigation criteria. The risk

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assessment, decision, and rationale regarding application or potential application of an ESV system on a natural gas storage well (in a depleted hydrocarbon or aquifer reservoir) is a duty of a storage operator under the requirements of API 1171, Clause 6.2.5. The authors highlight the risk management process recommended to operators for use in the decision-making processes. Good decision making is transparent and assesses the outcomes of past decisions.

The authors recommend that storage operators engage in the following continual improvement actions:

- ✓ Follow the risk management process and minimum evaluation requirements in API 1171, Section 8, and clause 6.2.5, and share lessons learned and good practices through industry associations;
- ✓ Follow the additional guidance around risk management discussed in this Appendix and establish a consensus as to some uniform, minimum risk management process detail;
- ✓ Develop templates and methods to gather and share information regarding reliability of various well barrier element system components, including surface and subsurface ESV systems;
- ✓ Establish partnerships between operator groups and stakeholder groups to evaluate reliability of ESV systems and system components, with goals to establish, evaluate, and report safety performance and develop guidelines for good practices in integrity management and ESV system reliability management; and
- ✓ Collaborate through industry associations and regulatory agencies to develop common integrity management goals and establish regular forums where operating experiences can be shared and employee knowledge, skills, and experiences can be developed and enhanced.

Section 1. Overview

This Appendix was developed to assist with the understanding of emergency shutdown valve (ESV) systems, including type, typical application, usage, reliability, and determination of need based on site specific risk assessment. The data presented in this Appendix is a combination of available industry publications, recommended practices, standards, company experience and historical data.

An ESV system includes an actuated valve designed to close upon reaching previously defined operating threshold parameters. Common parameters include, but are not limited to, pressure, temperature, or flow rate. Valves can be actuated by mechanical, electrical, pneumatic, or gas-driven means. ESV systems can be located above or below the ground surface on gas storage wells. Below grade ESV systems can be further classified into shallow or deep set designs.

An ESV system typically consists of several components, including but not limited to:

1) Valve Control System (VCS) – Portion of an ESV system where logic is utilized to perform a specific action or set of actions upon reaching a pre-determined parameter (such as pressure, temperature, or flow rate thresholds). This system typically consists of a manifold, sensors, and a power source to control the valve. Hydraulic, electrical, mechanical, or other means are used to control the valve.
2) Valve – Typically a gate (flapper) or ball valve depending on its location within the well, wellhead tree, or adjacent to the wellhead. Based on the site specific characteristics of the well, the location of the valve could include:

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a. Surface Controlled Surface Safety Valve (SCSV) – A valve placed above grade in the wellhead tree or adjacent to the wellhead which is controlled by a surface VCS.
b. Surface Controlled Subsurface Safety Valve (SCSSV) – A valve placed below grade in the well casing or tubing which is controlled by a surface VCS.
c. Subsurface Controlled Subsurface Safety Valve (SSCSV) – A valve placed below grade in a well casing or tubing which is controlled by a subsurface VCS.

3) Emergency Shutdown Valve System (ESV) – Components of an overall system including, but not limited to, a valve, the VCS, tubing or lines used to control the valve, flow couplings, or other downhole or surface assemblies used in the control and operation of the valve.

ESV systems are used in numerous applications, including offshore and gas storage environments. In offshore production wells, ESV systems are used below the mud line, or the sea floor, to control a well in the event of damage to the exposed part of the wellbore above the mud line from causes such as a hurricane, boat anchors, or other external event. Surface ESV systems are also used in cavern storage. API 1170, *Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage*, requires the use of surface ESV systems in cavern storage wells. Both API 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,* and CSA Z341, *Storage of Hydrocarbons in Underground Formations*, require that a site specific risk assessment be performed for each well in reservoir storage to determine if an ESV system should be installed per the specific conditions at the location. Numerous other industry publications and standards recommend material, service, or maintenance guidelines for ESV systems.

An ESV system is a tool available to operators and is not intended to be a one size fits all solution. A gas storage well ESV can assist in controlling unrestricted flow from a well or wellhead for a specific set of conditions for which it is designed. But, based on available literature, a downhole ESV system reduces consequences of relatively few events since the likelihood of a loss of containment event occurring during normal operations is unlikely.

While an ESV can assist in controlling the unrestricted flow from a well or wellhead and thus serve a risk reduction role, literature sources and company experience suggest the application of ESV systems could add additional risk due to reliability issues with the components of the ESV system. Industry experience has established evidence of mean time to repair/mean time to failure and direct and secondary reliability issues related to flow interruptions, test failures, partial closures, and service capacity and reliability. The reliability issues cause an increased well re-entry (service) rate, which also carries a loss-of-containment risk.

Secondary methods can be employed to detect, respond to, and reduce a loss of control event into the tolerable risk range with or without an ESV system. Secondary methods include, but are not limited to: gas/flame detection monitoring equipment, annulus pressure monitoring, emergency plans for rapid response well kill or control, pressure test verification of containment barriers, pressure monitoring and control equipment, and, during workovers, regular blow-out preventer (BOP) testing and maintenance of dual barriers.

When evaluating the use of an ESV on a well, operators typically follow a defined decision making process, which includes:

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1) Objectives clarification, where the operator defines the goals of their analysis by reviewing site specific conditions, operational characteristics, and environmental factors relevant to their operation.
2) Identify risk sources including hazards, threats, and potential hazardous situations. This analysis should also identify barriers to loss of containment events and identify gaps in the condition and effectiveness of barriers. Reliability issues with barriers could be common to other parts of the oil and gas industry and storage operators should consult technical literature sources.
3) Determine likelihood of well failure (loss of containment events) and potential impacts based on site specific conditions and incident duration.
4) Operators should follow a site-specific, risk-based assessment. After the assessments, operators prioritize wells by the risk estimated in the assessments and establish programs to prevent events by reducing the likelihood of the causes of gas containment failure and mitigating the consequences of a loss-of-containment event. This analysis should be performed on a well by well basis.

Consequence mitigation factors that tend to influence the decision to install an ESV system include proximity to places of habitation, roads, human gathering places, environmentally sensitive areas, other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. Event potential factors that could influence the decision to install ESV systems could include site-specific potential for impact due to natural forces (earth movements, seismic activity, floods, severe weather events, and other earth forces) or human-induced activity that could lead to forces adverse to well integrity.

Operators can develop risk management plans that might include ESV systems for wells defined in the integrity assessments as located within a significant impact radius potential of receptors or potentially subject to uncontrollable events from human or natural forces; the risk assessment and risk management plan should focus particularly on wells with capacity to flow at high rates and/or long durations.

Section 2. Description of ESV Systems

Locations of ESVs

Emergency Shutdown Valves can be located above ground (surface safety valves (SSV)) or below ground (subsurface safety valves (SSSV)). Operators choose the appropriate locations and configurations to meet their specific needs. API 14B, *Design, Installation, Repair and Operation Subsurface Safety Valve Systems,* provides definitions for safety valve systems, types, and components (API 14B - 3.20 SSSV system equipment; 3.21 surface-controlled subsurface safety valve SCSSV; 3.22 subsurface-controlled subsurface safety valve SSCSV; 3.23 subsurface safety valve SSSV; 3.24 surface control system; 3.25 surface safety valve SSV).

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2.1 Surface Safety Valves

The SSV is part of a safety system to isolate the wellhead from the associated surface piping. This system consists of an isolation valve (typically a gate valve), a valve actuator/operator, and a valve control system (VCS). As this system is entirely above ground, all components are easily accessible for verification, testing and maintenance. Under normal operation, the VCS holds the SSV open. If the VCS detects an operational anomaly at the wellhead, such as excessive pressure or temperature, it allows the actuator to close the SSV.

2.2 Subsurface Safety Valves (SSSV)

The SSSV is a part of a flow shutdown system installed within a well to prevent uncontrolled flow. The SSSV can be in-line with the production tubing (tubing-retrievable) or be installed within the production casing (wireline-retrievable). There are several different SSSV configurations, each with their own advantages and disadvantages. The characteristics that differentiate the configurations of SSSVs are the locations of the valves (shallow-set vs. deep-set) and locations of the VCS (surface controlled vs. subsurface controlled).

Operators make decisions on the use and subsurface location of the SSSV based on a risk assessment balancing the risk reduction benefits of consequence mitigation and protection of potential receptors with the risk increase related to reliability of the SSSV, as described in more detail in following sections. The SSSV setting depth is a function of what the operator is trying to protect and the potential consequences the operator is trying to reduce. An operator could consider installing a shallow-set SSSV if the most significant threats relate to wellhead or surface network failure; an operator could consider installing a deep-set SSSV if there could be increased risk of casing or tubing failure deeper in the well.

Increasing the depth of the SSSV installation increases the technical difficulty and reliability related to surface-controlled systems and can also decrease flow capacity and reliability in many wells. Subsurface-controlled valves require set-points of flow rate/flow velocity or pressure differential in order to activate, which means that the subsurface-controlled valve will not activate until these conditions occur and there will be leaks of some magnitude for which the valve will not close. The working inventory pressure range and flow rate and velocity range of many storage wells complicates the set-point design and applicability of subsurface-controlled valves.

Deeper-set surface-controlled SSSV reliability issues are related to adverse mechanical operability impacts that can result from changes in flow or solids and liquids in the flow stream. The SSSV valve closure mechanism can be fouled or deteriorated by collection of organic and/or inorganic solids, erosion or corrosion of mechanical elements, or scouring, any of which can reduce functional performance and reliability. The effectiveness of the surface control system depends on the integrity of the hydraulic VCS control line and the control fluid, both of which are reduced due to the complications related to increased depth. (API 14B defines “control line” as the conduit utilized to transmit control signals to the surface-controlled subsurface safety valve. The “surface control system” is the surface equipment including manifolding, sensors, and power source to control the subsurface valve). Deeper-set surface-controlled SSSV systems have higher rates of reliability issues because the system itself is “bigger,” deeper, and therefore exposed to more hazards than shallower-set systems – as an

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example, depth limits exist due to inability to overcome fluid mechanics and pressure drop in small-diameter control line tubing. Literature reviews summarized in Appendix 2 document lower reliability rates for deep-set systems.

2.2.1 Surface-Controlled Subsurface Safety Valve (SCSSV)

A Surface-Controlled Subsurface Safety Valve has its VCS above ground. Typically, the control system controls the SSSV with a hydraulic pressure line. If the control system senses an upset or becomes unresponsive, the SSSV internal spring closes the valve.

2.2.2 Subsurface-Controlled Subsurface Safety Valve (SSCSV)

A subsurface-controlled subsurface safety valve is a self-controlling valve. It is configured to close based on the differential pressure through the valve (where differential pressure can be associated with gas flow/velocity) or by pressure in the tubing (pressure type).

2.2.3 Subsurface Safety Valves Deep-Set

A deep-set SSSV (see Figure 1) is installed near the bottom of the well, generally thousands of feet below the surface.

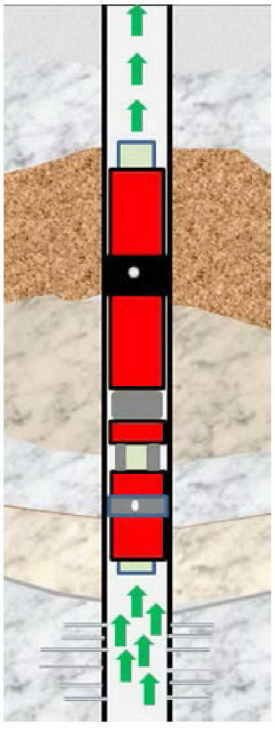

Figure 1: ***Subsurface Safety Valves Deep-Set***

2.2.4 Subsurface Safety Valves Shallow-set

A shallow-set SSSV is installed below the wellhead but near ground level. Typical depth below ground level for a shallow-set SSSV range is within 200 feet of the wellhead.

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Section 3. Application and Experience with ESV in Underground Natural Gas Storage

The following discussion examines the benefits and potential risks of SSSV.

Brief history

SSSVs are typically installed in offshore oil and gas production wells where there is a chance the wellhead can be broken off above the sea floor due to mudslides, dragging ship anchors, and tropical storms damaging drilling or production platforms or vessels. The subsurface valves are typically installed in the production tubing upon completion of the well, ~100 feet below the mud line.

Onshore, several North American natural gas storage companies installed SSSVs in a subset of the former production wells when the depleted reservoirs were converted to gas storage. These shut-off valves were generally installed less than 200' below the surface in the depleted reservoir wells and in a few aquifer storage wells near residential communities or high traffic roads. The valves are designed to fail closed upon loss of hydraulic pressure supplied by the VCS.

Natural gas storage operators carefully evaluate new installations of SSSV. As described in the operator testimonials located in Appendix 1, there are potential benefits from installing SSSVs but there are also operational impacts and a number of risks associated with the installation and operation of SSSV.

Benefits of SSSVs/DHSVs

SSSVs can be an effective means of significantly reducing the gas flow from a well if the wellhead is catastrophically damaged or severed or if a large leak occurs in the casing or tubing above the setting depth of the valve. As discussed in Section 2.2.3 and 2.2.4, an SSSV can be installed as a deep-set or shallow-set valve within well tubing, just below the wellhead, and/or in the casing above the casing perforations, several thousand feet below the wellhead. In a shallow-set installation, generally within 200 feet below the wellhead, the SSSV closes in the event the wellhead is extensively damaged or a tubing leak develops below the wellhead and above the SSSV. For the deep-set location (near the bottom of the well), the SSSV paired with a packer and a full tubing string could potentially isolate the entire tubing string if the wellhead is damaged or the tubing develops a leak. As most deep-set SSSVs are hydraulically controlled by a VCS, the maximum depth is often limited by the allowable hydraulic pressure at the SSSV.

The SSSV and the SSV are intended to function as consequence mitigation barriers, closing down flow from a well in the event of a large, even catastrophic leak. An "event" of significant magnitude or force must occur in order for the valve to activate; the event must cause a loss of control pressure or a substantial pressure, flow, or velocity change. Whereas casing and cement around the casing function as "passive" technical (physical) barriers to contain the gas at all times and with no special effort, ESV systems are technical control barriers that function only in the case of a triggering event. The distinction in barrier category is critical in order to understand that the functional purpose, reliability, and set point location of the ESV system limit its risk reduction capability to only those scenarios in which the ESV system would activate. However, since wells have limited means of shut-off in the event of a leak, ESV systems provide a means to perform a self-activated closure and thus ESV have risk reduction value in selected situations where flow from a well would be at high rate for an extended period and not be controllable within reasonably short time periods through other means. API 1171 requires that storage

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operators evaluate the risk reduction value of ESV systems in each well and use the risk assessment to decide on use of an ESV system in any particular well.

While the operator testimonials in Appendix 1 represent well over 5,000 well-years of operation with SSSV, it is difficult to find cases where operators cite instances where the SSSV functioned in response to a legitimate triggering event.

Operational Impacts of deploying SSSV in Depleted Reservoirs and Aquifers

Per Section 2.2, there are two typical SSSV installation types and they have different impacts on operations. The first installation type is a tubing-conveyed SSSV installed in a tubing string, generally with a very similar cross-sectional flow area as the tubing. The second is a wireline-conveyed SSSV installed in the flow tubular, which sets the entire assembly inside the flow tubing and therefore has a smaller cross-sectional flow area than the tubing. The tubing-conveyed and the wireline-conveyed systems can be installed at various depths, although if the operation of the valve is surface-controlled, the depth of setting is influenced by the design and reliability of the control line and control fluid. Well operating pressure, flow fluid composition, flow tubing size, and other factors, in addition to the control line and control fluid, influence the setting depth restrictions for a Surface Controlled Subsurface Safety Valve (SCSSV). Natural gas storage operators, when using SCSSV, generally have installed the valves at shallow depths.

New wells planned with SSSVs and tubing have customized wellheads designed to support the connections and the weight of the tubing and the SSSV. The new wellheads contain fittings with bowls designed to suspend and secure the tubing hanger. Existing wells must be taken out-of-service to install tubing and SSSVs. Installing an SSSV on tubing in an existing well requires many steps to modify and add the connections necessary to support tubing and SSSV controls to the existing wellhead. Generally a new wellhead is required after obtaining the location-specific design. The existing wellhead must be removed and modified or replaced. Before removing the wellhead the well must be shut down and controlled ("killed") to render it safe, then heavy equipment (a rig and related equipment rated for the forces expected during the well intervention/service work) is brought in to disassemble and remove the wellhead and install a blowout preventer ("BOP"). Tubing and SSSV assembly (with control lines) are installed in the well and the tubing is hung in the new wellhead assembly, which includes a tubing hanger and tubing valve. Note that this new tubing valve becomes the master valve controlling flow from the well when the flow is coming from the tubing only. Once the downhole installation is complete and pressure tested, the surface control system is connected and tested to ensure functioning of the SSSV in accordance with standards and specifications.

From that point forward, the SSSV and its controls will be tested annually, or more frequently if conditions warrant, to ensure proper operation. The well must be taken out-of-service during SSSV system removal, installation, testing, intervention, modification and repair and/or wellhead modifications related to the SSSV system. Natural gas storage operators must make risk-based decisions with respect to taking a well out of service if an SSSV fails a function test; the decisions are predicated on the values of safety, environmental stewardship, and storage service reliability.

Installing tubing and an SSSV within the well reduces the cross-sectional flowing area by approximately 50 percent, depending on the size of the tubing - if the tubing is half the diameter of the casing, the flowing area is reduced ~75 percent. The reduction in flowing area causes a pressure drop which could

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reduce deliverability during critical periods from a negligible range to more than 50 percent, depending on the well flow capability and operating pressure range. If the flow deliverability requirements remain the same for a gas storage field, then new gas storage wells must be drilled to make up for the lost capacity. Each storage well operator must carefully evaluate the deliverability impact of tubing and SSSVs to ensure their fields can deliver the gas to serve market demand, including residential heating and power needs on a peak or cold, high-demand winter day, as well as on the last day of withdrawal, when storage field pressures are much less at the low end of seasonal inventory.

An SSSV installed in the tubing string adds operational challenges and safety considerations. The operator incurs additional risks to extricate the tubing and the SSSV from the well in order to perform the manufacturer-recommended maintenance to the valve or when the valve fails to properly operate or seal during testing. SSSV and tubing removal might require a snubbing unit, much larger equipment than the more typical wireline truck used to run tools, which increases risk to operating personnel charged with removing the valve when maintenance is required.

Casing mounted SSSVs are typically installed using wireline. In both cases the valve itself restricts the flow path, which can cause pressure loss which reduces deliverability, contributes to a buildup of paraffin or inorganic scales, increases maintenance demands for valve service, and causes unnecessary shut-ins when the valve closes prematurely or fails open, closed or partially closed.

Additional Risk Introduced by SSSVs

The risks introduced to a well associated with SSSV include the installation, malfunction and failure of the SSSV components. Adding SSSVs to existing wells requires shutting in the well, killing the well - usually by installing plugs and adding water to control well pressure - replacing the wellhead and installing the SSSV, often on a tubing/packer string. These steps, while manageable, expose the operator and environment to risks of uncontrolled releases. Well servicing exposes workers and nearby public to loss of energy in the event of well re-entry to remove and service a valve after an unintended closure or malfunction of the SSSV.

SSSVs can fail and/or function improperly due to a number of circumstances including but not limited to hydraulic leaks and contamination by solids, which impair the function of SV components. Surface controlled SSSVs have suffered from control failures, seal and tubing leaks and malfunctions which cause the valve to close. A tubing-retrievable SSSV is connected to the tubing and lowered in the well with a drilling or service rig. If a leak develops in the hydraulic control line or any of the seals, a drilling or service rig must be brought in to retrieve the SSSV from the well. Until a rig can be brought in, the well remains closed and unable to deliver gas. Every time the SSSV is removed from the well for replacement, repair, or servicing, some methane is vented to the atmosphere. While the gas loss quantity per installation is minimal, if SSSVs were required for all gas wells, then the gas loss volume would multiply by thousands. As SSSV have some well-established reliability ranges, the increased well interventions to pull the valve for well casing inspection or to service and repair the valve would increase methane emissions.

API 1171 recommends periodic inspection of the production casing integrity. Inspecting the casing involves the use of tools that make contact with the casing wall to detect the location, size, and shape of any defect that may be present. Many of the analytical tools available to perform detailed casing inspection require removal of the tubing, SSSV and packer isolating the tubing. Because SSSVs and

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tubing are installed inside the well casing, they impede the entry and exit of analytical tools, such as well profile calipers, into and from the well. This impedes an operator's ability to proactively assess the integrity of the well via casing inspection and flow logging/detection programs. In order to maintain surveillance of the condition of the casing, casing inspection tools and flow detection devices can be run inside a "casing" completion, and follow-up surveys can be directed to various frequencies depending on the findings of a survey or depending on a combination of other factors that recommend for inspection. An SSSV/tubing string installation increases the cost and complexity of casing condition monitoring.

SSSVs do not arrest all leaks. A shallow SSSV installation does not shutdown the flow of gas through a deep casing breach occurring below the set point of the SSSV. Shallow SSSVs are only designed to limit the amount of escaping gas in a catastrophic surface event. The closure mechanisms might not actuate in the event of a steady but small leak that does not meet some threshold of pressure or flow differential or velocity.

SSSVs are not completely gas tight over time due to the normal yet relatively harsh operating conditions in many storage well situations. The sealing surfaces can be exposed to the flow of gas, water, and other components such as sand. A scratch of just a few thousandths of an inch may prevent a flapper or ball SSSV from achieving a complete seal. The SSSV can still be effective in minimizing gas loss in an extreme abnormal event. Specifications such as API 14B define an allowable leakage rate that must be carefully reviewed for practicality as it would not make sense to extract a SSSV hundreds to thousands of feet below the earth's surface for a trace leak that is only detectable during a test when the valve may be in very good condition and fully capable of arresting nearly all of the flow in a catastrophic surface issue.

SSSVs prevent the installation of a full size plug in the well, impeding resolution of a potentially hazardous situation or significant leak event. SSSVs, regardless of where they are installed, are only effective in limiting a leak that is located above the SSSV. However in the very unlikely event that a downhole leak occurs, the SSSV reduces the operator's ability to deliver an effective treatment because repair tools must be small enough to fit through the SSSV without getting caught in the length of the SSSV profile. Generally, for efficient well intervention and isolation in a leak event, restrictions inside the casing could and often do need removal. Deep set subsurface safety valves increase risk of problems and prevent the operator from setting a plug to control a well unless an additional packer is set beneath the point where the SSSV is set; such an arrangement retains a risk due to time and complexity for extraction of the tubing string and SSSV, relying on the lower packer plug to hold for a long period of time and hoping that no problems occur with the extraction or re-insertion.

Cost of SSSVs in Depleted Reservoirs and Aquifers

Two of the operator-authors of this Appendix developed independent estimates of installation and servicing costs related to ESV systems, particularly SSSV, and associated costs for a full tubing string on an isolation packer and wellhead accommodations; the operators also estimated the cost of drilling new wells and equipping those wells with SSSV on full tubing strings. The operators developing the estimates represent nearly 2000 natural gas storage wells and 40 gas storage reservoirs, a wide range of pressure, depth, flow potential and geographic location. The cost estimates of each operator's independent determination compared favorably and so the summary below represents the range found by both analyses.

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There are five major costs associated with SSSVs: the cost of the valve, the cost of installation, the routine operations and maintenance (O&M) costs relating directly and indirectly to the presence of an SSSV system, the life cycle costs of the SSSV system itself including capital replacement costs, and the cost of additional facilities because of the loss in throughput and other risk and risk treatment interdependencies.

The direct cost of an SSSV depends on size, and typically ranges from $15,000 - $140,000. The total estimated installed cost for a SSSV/full tubing string and packer in a 7" production casing string is ~$250,000 per well, with a wide range - greater for deep wells and lower for shallow wells. Considering that there are approximately 12,000 to 14,000 gas storage wells in the United States without tubing/packer and SSSVs, the cost for installation in all wells would be on the order of $2 to $4 billion. Operations and maintenance costs could average $2,000 per well annually, for a range of $25 -$50 million for basic maintenance added across the gas storage industry. The life cycle cost could be significant based on reported reliability of the valves. Some wells may require workover or snubbing rigs and multiple valve replacements over a 100-year well lifetime at an estimated total industry cost of $10 billion, or roughly $100 million annually.

The cost for replacement of lost capacity resulting from the installation of tubing, packer, and the SSSV can be represented by the cost of drilling additional wells. New well drilling requirements depend on a number of factors and how those factors contribute to deliverability and/or service reliability impairment if SSSV on full tubing strings were installed; the impact factors include well depth, pressure, flow potential, and the significance to the amount of cross-sectional flow area restriction along a length of the well. The new well drilling analysis assumed that horizontal drilling techniques would be used to provide the service restoration. The analysis yielded an estimate in the range of 1,000 to 5,000 new wells that could be required to replace the lost deliverability resulting from installation of SSSV on tubing. The well replacement cost range is estimated to be between $2 and $10 billion.

SSSVs in Salt Cavern Storage Wells

Salt cavern gas storage facilities have been developed for gas storage. These underground facilities tend to be 1970s-2010 vintage facilities and were developed using new drilling and well completion techniques, utilizing multiple concentric large diameter casings, ranging from 16 inches up to 42 inches, whereas the traditional production wells are less than 10 inches in diameter. The cavern wells have a minimum of two barriers into the salt. Wellhead shut-off valves are installed on every well. Emergency Shutdown Valves (Surface Valves) are required by API 1170 and CSA Z341.2. Surface valves enable the operator to isolate both the gas well and the gathering piping system. Because SSVs are above ground, they are easier to inspect and maintain as compared to subsurface valve systems. The stroke and operation of the valve can be observed directly by the technician and adjustments can be made when deemed necessary. Service ports and grease fittings are readily accessible and can be serviced annually with minimum effort or special tools.

Comparison and Contrast of SSSV and a SSV

Both SSSV and SSV are comprised of multiple components to ensure that they fail closed when needed. As depicted in Figure 2, the SSSV offers a narrow flow path (light green) whereas the SSV ball valve shown to the right is full opening (steel ball port is the same size as the piping) causing virtually no

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restriction. The SSSV must be removed to be serviced. Above ground valves can be readily serviced, in many cases without impeding the flow of gas.

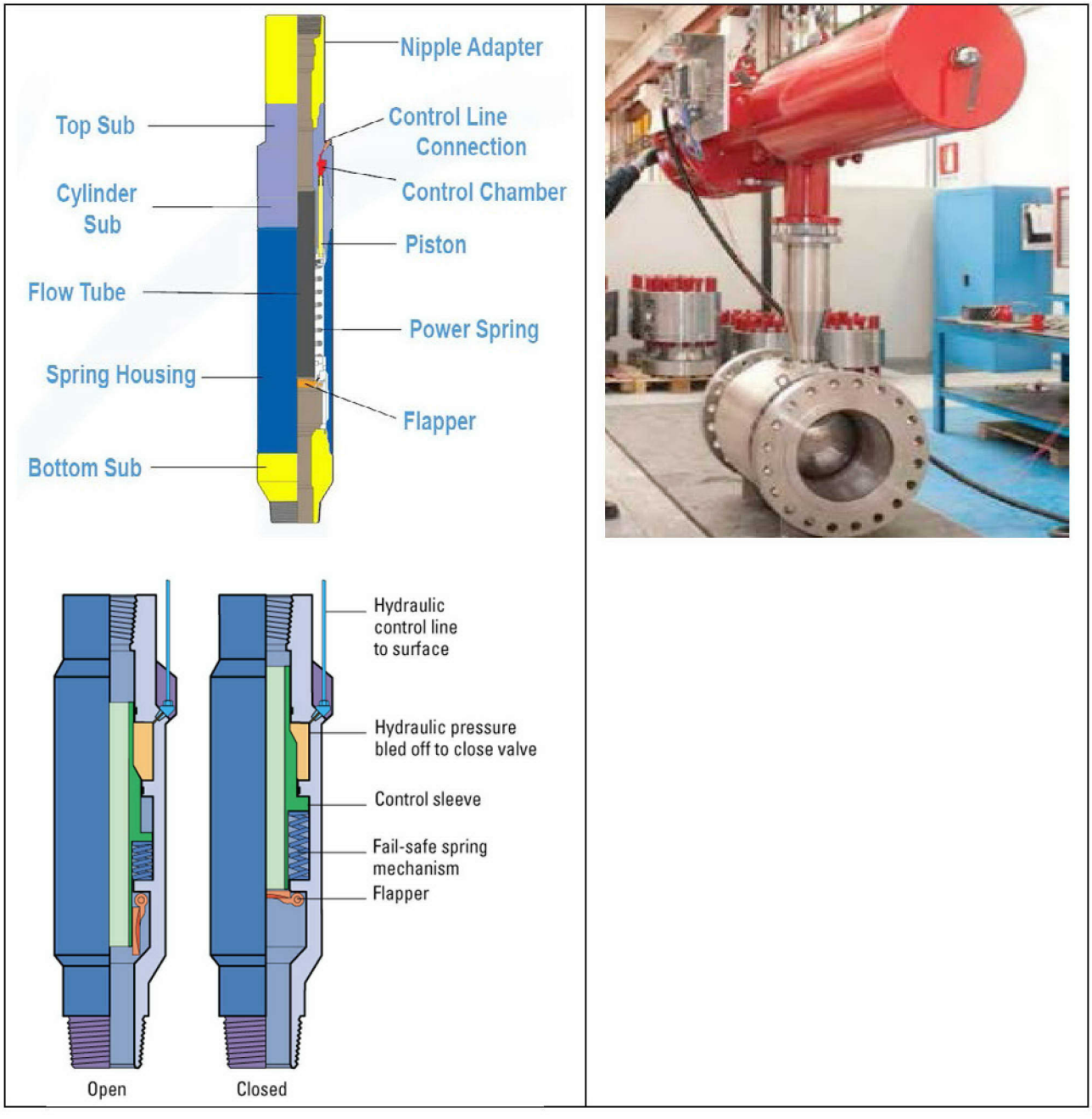

Figure 2. (Left, top and bottom) Subsurface Safety Valve profile (flapper type), and (right) Surface Safety Valve (ball valve type). (Figures courtesy of Baker Hughes)

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ESV Reliability - Company Operating Experience

Five storage operators shared their experiences of operating wells with various ESV systems. The dataset from these five operators represents nearly 200,000 well-years of total storage well operation, and over 5,000 well-years of ESV system operation, most of it downhole safety valve system operation.

Appendix 1 contains each operator's more detailed discussion of the experience, the risk assessment used, the reliability and safety issues involved, and the performance impact of subsurface safety valves in particular.

The storage operators represented in Appendix 1 provide some quantitative reliability information: safety valve function test and operating failure rates are in the 0.01-0.03 failures per well-year range – note that this failure rate is inclusive of all causes of failure, not just the mechanical failure of the valve mechanism itself.

Re-entry-and-removal/replacement rates for subsurface safety valves are in the range of 0.1-0.2 entries per well-year, a rate that is composed of entries for SV inspection and repair, entries for test/function failures, and entries for casing inspection.

Flow and function reliability issues related to downhole safety valves include hydrates, salt, or paraffin bridging in the safety valve assembly, or function test failures due to the same types of bridging agents fouling the flapper closure mechanisms. The corrective maintenance issue, or reliability issue, rates are in the range of 0.15 per well-year of operation. However, the annual corrective maintenance rate varies with storage field/well use and winter severity. Corrective maintenance actions include flushing with solvents such as water, methanol, or heated diesel oil, and in many instances these are successful in restoring flow and proper valve function.

Some storage operators report substantial flow restrictions due to subsurface safety valve installation. High deliverability well flow can be adversely impacted by restrictions in flow diameter along the length of the tubing string on which the safety valve is run. The decrease in flow due to the tubing and subsurface safety valve system could cause the operator to drill more wells to replace lost service reliability. Additional tubing, packer, and safety valve systems could increase the number of well re-entries due to known reliability rates related to mean time to repair/mean time to failure for tubing, packer, safety valves and additional wellhead components.

Storage well applications of ESV and related equipment, loss of containment rates, well component failure rates and inter-dependent risk

In 2011, a survey of ESV systems in non-cavern storage wells solicited storage operators to provide voluntary responses to a number of questions, including whether the operator used any type of ESV system (surface or subsurface) on any wells in their storage assets, the criteria used for decision-making on application of ESV systems, and whether the operator was evaluating use of ESV systems of any type in the future.

The survey yielded responses from 22 storage operators representing more than 8,500 wells, or about half of all storage wells in North America. Approximately 30 percent of the operators did not use any ESV system in their wells, but approximately 11 percent of all wells represented in responses had some

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type of ESV system and some wells had both surface and subsurface systems. Overall, only four percent of wells represented in the survey had subsurface safety valve systems.

The reasons for ESV system use included well flow potential in ~27 percent of cases, well pressure in 18 percent of cases, proximity to receptors in 27percent of cases, loss prevention in 27 percent of cases, and other or no reason given in 23 percent of cases (some respondents cited multiple reasons thus the percentages do not total 100 percent). Only two of 22 respondents indicated they were considering additional ESV system installations and were using risk assessment to make the decisions.

In addition to the storage operator shared information, Appendix 2 contains summaries of several Society of Petroleum Engineers papers regarding reliability of safety valve systems.

The authors also referred to the March 2005 report to the Gas Research Institute under Contract No. 8604, Project No. 809833, "Risk Assessment Methodology For Accidental Natural Gas and Highly Volatile Liquid Releases From Underground Storage, Near-Well Equipment," prepared by Glenn DeWolf, Katherine Searcy, Douglas Orr, and Christopher Loughran on behalf of URS Corporation.

The discussion of ESV systems and their applicability and reliability necessarily involves a discussion of the reliability of the entire well system and the inter-dependent nature of physical components and human interactions in the analysis of risk. Loss of containment rates and reliability rates obtained from the compilation of sources is summarized in Table 2 and contains a summary of well and selected well component failure rates. Reliability rates for tubing/packer systems and wellhead systems are included in Table 2 along with casing, cement, and loss-of-containment during drilling or service intervention ("workover") since all components and work types represent failure paths leading to potential loss of containment events.

Table 2. Summary of Well and Selected Well Component Failure Rates, Reliability Rates, and Impact Analysis

case	min	max	mean	source
loss of containment, drlg - "known areas", per well	0.0002	0.0003	0.00025	compilation, industry data
loss of containment, workover, per well	0.00007	0.0004	0.000235	compilation, industry data
loss of containment, re-entries, per re-entry	0.0000891	0.000341	0.000215	URS (2005)
loss of containment, re-entries, per re-entry			0.000680	Durham and Pavely (SPE #56934)
tbg/csg fail, per well-yr			0.0000034	Busch, Policky, Llewellyn (1985)
tbg fail, per well-yr			0.002	Busch, Policky, Llewellyn (1985)
wh fail, per well-yr			0.000012	Busch, Policky, Llewellyn (1985)
cement - failure per well-yr			0.000064	URS (2005)
casing (no cement) - failure per well-yr	0.000016	0.000029	0.000023	URS (2005)
csg fail (2 or 2+ barrier - csg, cmt, etc), well-yr		0.000015	0.000007	one storage operator testimonial
well fail with shallow set SCSSV - per well-yr			0.000049	URS (2005)
well fail with shallow set SCSSV - per well-yr	0.00006	0.00008		Moines and Iversen (1990) OTC #6462
Surface SV fail, per demand			0.000000071	URS (2005)
Subsurface SV failure, per demand	0.000004	0.000020		URS (2005)
SSSV functional failure/repair per well-yr	0.01	0.03		Storage operator experience

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SSSV functional failure.repair per well-yr	0.02	0.03		Durham and Pavely (SPE #56934)
SSSV functional failure/repair per well-yr			0.027	Moines and Strand (SPE #63112) - 1999 MTTF
tubing-packer systems - repair/re-entry per well-yr			0.032	one storage operator testimonial

The authors of this Appendix estimated the current storage industry usage rates of ESV systems and tubing/packer systems based on the industry surveys referenced above and informal discussions and personal communications. The first few lines of Table 3 show the estimate that three to five percent of natural gas storage wells have SSSV and 10-25 percent of natural gas storage wells have a full tubing string set into an isolation packer.

The authors estimated the impact to service reliability and well service intervention rates if the use of SSSV and tubing/packer systems were applied to all natural gas storage wells, in order to demonstrate the inter-dependent nature of well component reliability and well intervention risk. The authors estimate that the widespread installation of tubing/packer and SSSV would result in a service reliability replacement demand that could result in a five to 25 percent increase in the number of storage wells. The total impact of all SSSV and tubing/packer installations is summarized for both existing wells and potential new well additions to show that there would be a likely impact to more than 16,000 storage wells. The remaining rows of Table 3 show the authors' estimates of failure rates of the components and failure rates due to well servicing loss of containment. The risk of loss of containment is increased by the count rate addition due to installation multiplied by the re-entry rate due to component failure, multiplied by the loss-of-containment rates during well intervention.

Table 3. Impact Estimate		min	max
Number of storage wells, approximate (AGA Underground Storage Survey 2013)	17600		
Estimated percentage with SSSV (Author estimates)	4	3	5
Estimated wells with SSSV (Author estimates)	704	528	880
Estimated percentage with tubing-packer systems (Author estimates)	13	10	25
Estimated wells with tubing-packer systems (Author estimates)	2288	1760	4400
Estimated percent well additions for tubing restrictions to restore and maintain deliverability and capacity (Author analysis estimate)	10	5	25
Estimated well additions (percentage in line above converted to a number) (Author analysis estimate)	1760	880	4400
Added SSSV and tubing/packer systems (if "all wells must") (Author analysis)	14608	15312	12320
Including new wells (if "all wells must") (Author analysis)	16368	16192	16720
Minimum re-entry rate per well-yr SSSV+tbg/pkr system MTTR (Author estimates and company testimony)	0.037		
Increased re-entries, minimum estimate, per year (min) (Author estimates)	606	599	619
Maximum re-entry rate per well-yr SSSV+tbg/pkr system MTTR (Author estimates)	0.062		
Increased re-entries, maximum estimate, per year (max) (Author estimates)	1015	1004	1037

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Loss of control, well re-entry (high value,Durham/Pavely)	0.00068		
number of wells re-entered for MTTR (max) (Author estimates)		1037	
expected number of loss of control incidents, per year, for wells re-entered for SSSV/tbg reliability (HIGH VALUE) (Author analysis/estimate)			0.705
Loss of control, well re-entry (low value, URS)	0.000215		
number of wells re-entered for MTTR (max) (Author estimate)		599	
expected number of loss of control incidents, per year, for wells re-entered for SSSV/tbg reliability (LOW VALUE) (Author estimate)			0.129

The authors summarize from Tables 2 and 3 that while SSSV systems can decrease risk in a loss of containment event, a greater application of subsurface well components and the inter-dependencies of equipment reliability rates and well intervention loss of containment rates would nullify the risk-reduction benefits of SSSV and could increase the risk of loss of containment.

Section 4. Standards and regulations applicable to the use of ESV

The natural gas storage industry integrity management in North America is guided by several standards. API 1170 - Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, and API 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, were published in 2015.

API 1171, in Clause 6.2.5, specifies that operators evaluate the need for an emergency shutdown valve in wells using as a minimum set of variables: distance from dwellings, potential dwellings, or outside areas where people frequent or congregate, fluid composition and maximum flow potential, distance from wellheads and other surface equipment, site access availability for remedial and emergency equipment, proximity to public transportation or industrial facilities, the current and future/expected state of development in the area, regional topography, drainage, and environmental considerations, and the added risk created by installation and servicing requirements relative to the ESV system and alternative protection/mitigation measures.

API 1171 specifies minimum annual shutdown valve system function testing and requires that a closed ESV system be manually reopened at the site of the valve after an inspection and not opened from a remote location.

API 1170 has a number of requirements for surface emergency shut down valves (ESD). Clause 8.4.1 of API 1170 requires ESD equipment during cavern development when solution mining under gas, re-watering, or de-brining. All flow courses from the wellhead to the production lines are required to have ESD, and the ESD should be connected to the SCADA system for control and monitoring (Clause 8.5.2). The ESD valve must be installed at or near the wing valve off the wellhead (Clause 9.2.2). Finally, Clause 9.4.4 covers periodic testing recommendations, which includes tests of all components of the system.

In Canada, the Canadian Standards Association (CSA) Z341 series apply (Storage of hydrocarbons in underground formations). In CSA Z341.1-14, Reservoir storage, an ESD valve is required if the operator determines the need as a result of a risk assessment (as per Clause 7.1) or if very close to a building designed for occupancy. The applicable radius of impact equation makes a simple relationship of

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pressure and well casing diameter to the radial distance from the building (see Clause 9.3.2.1). The radius-pressure-casing size relationship is based on an assumption of worst case well flow capacity, ignition of the gas, and a heat flux of 5.0 kW/m2 representing a 30-second burn threshold, as per the Gas Research Institute project GRI-00/0189.

API 1171 and CSA Z341.1 are very similar in the risk assessment consequence criteria; Z341.1 requires evaluation, in addition to proximity to potentially occupied buildings, of proximity to adjacent wells and other surface developments, the number of wells connected in common to surface pipe networks, the reaction time of the operator to shut in wells, and the storage capacity of the facility.

CSA Z341.1 requires that when an ESV system is used a valve must be installed on each flowline to the wellhead and as close as possible to the wellhead, pressure rated to maximum operating pressure of the well-pipe system, fail-closed and capable of position monitoring, remote and local operation, and automatic activation. If a subsurface safety valve is installed, it must be function tested twice per year and repaired or replaced if the function test fails. Greater function test frequency is recommended when operating conditions include corrosive agents, fouling/depositing/scaling agents, or the valve experiences large variations in temperature and pressure. Z341.1 also requires testing of the ESV control system once per year, including instrumentation, valving, shutdowns, wiring connections, and circuit integrity and closure times (Clause 10.2.2).

CSA Z341.2-14, Salt cavern storage, is similar to API 1170 in its requirements for salt cavern well ESV systems. Clause 9.3 has the same location and operability requirements as in Z341.1, but adds that closure times should be set to minimize hammering and that activation can occur by over-pressuring or under-pressuring of the hydrocarbon system, over-pressuring of the brine system, and high hydrocarbon temperature.

Material, Installation, and Service Specifications

API 14A (ISO 10432), Specification for Subsurface Safety Valve Equipment, provides functional applications compatibility, technical specifications for design, materials and manufacturing requirements, repair and redress, and shipping, storing and handling. The 14A Annexes cover testing, validation, and verification requirements.

API 14B (ISO 10417), Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, covers system configuration, equipment, documentation and data control. The Annexes cover redress, installation, operations, sizing of the system, testing, and failure reporting. API 14B covers acceptable leak rates when performing function tests.

API 14C addresses surface safety systems on offshore production platforms.

API 6AV2 superseded API 14H and treats surface safety valves and underwater safety valves.

General Well Integrity / Integrity Management Systems

ISO 16530-1, Petroleum and natural gas industries — Well integrity —Part 1: Life cycle governance, was published in 2015. ISO 16530-1 identifies an SSSV as a possible well barrier (Clause 4.7.3.4). ESD/SSV should be tested in accordance with API 6AV2 (Clause 4.9.2.2).

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ISO advocates definition of Safety Critical Elements (SCE); all parts of an ESD system are to be considered SCE (Clause 6.4.5) and increased maintenance frequency is recommended, along with documentation. In ISO 16530-2, Clause 15.4.2, notes that higher frequencies of function testing of SSSV can reduce problems found when verification testing is performed.

Operating limits and verification tests are to be operator-defined; Clause 5.6.2 includes considerations for SCSSV such as setting depth, control line actuation pressure, and well conditions.

ISO 16530 Appendix F provides a description of surface and subsurface safety valves (ESD), their function, and possible failure modes. A surface safety valve, the function of which is to provide shutdown and isolation of the well to production process/flow lines, can fail due to malfunction, mechanical damage, control line pressure problems, incomplete closure or unacceptable leakage. For a surface controlled subsurface safety valve, the function can fail due to lost communication with the control line, leakage above acceptance criteria, failure to close on demand or in an acceptable amount of time, mechanical damage, or other malfunctions. ISO cites the API 14B threshold acceptable leak rate as 15 SCF/min for gas (approximately ~22 Mscf/d).

Regulations

The authors are not aware of any state oil and gas regulations that require the use of downhole safety valves in onshore wells. Surface safety systems, including emergency shut down valves, are required in cavern storage operations in a number of states. In the US and Canada, cavern storage operations need surface safety systems, including emergency shutdown valves, and the requirement is embodied in the industry recommended practices of API 1170 and CSA Z341.2.

The Bureau of Safety and Environmental Enforcement (BSEE) regulations (Title 30, Chapter II, Subchapter B, Part 250, Subpart H , §250.801) require offshore production wells capable of flow to have downhole safety valves and platform safety systems, including emergency shut down systems.

- 250.801 (c) stipulates a preference for surface-controlled subsurface safety valves installed in a tubing string and requires that such a valve be installed when the tubing is next serviced.
- The depth of the valve must be at least 100' below the mud line.
- The need for a safety device in offshore wells is due to lack of accessibility to the well and the hazards of the offshore environment. Where a subsurface safety valve is not installed, the well shall be attended "…in the immediate vicinity…"

BSEE 250.802-250.808 addresses surface safety systems, which must be installed on all production facilities offshore. The regulations address design, installation, testing, quality requirements for closure times and leak rates, and other related performance factors, including personnel competence, training, and attentiveness to the safety systems.

In summary, regulations requiring emergency systems inclusive of surface or subsurface safety valves exist today in settings where risk of loss of containment is elevated due to:

- High consequences of failure, including rates of flow and radius of impact, fire potential, and escape capability of workers or the public;

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- Discharge into water, air, or land is difficult to confine and contain within a limited space;
- Accessibility and timeliness of human intervention emergency response services is hampered due to well location;
- Impact to other infrastructure could create cascading events; and
- Hazards are difficult to anticipate and manage, and such hazards might include forces of nature, high pressure, high temperature, flow stream composition, rate, and extended volume potential, and duration of a loss of containment after a loss of containment event occurs.

Section 5. Risk management and decision-making

Section 8 of API 1171 requires that operators develop risk management processes with risk source identification, risk analysis, evaluation of risk and the ability to control risk by implementing risk treatments such as preventive, mitigative, and monitoring programs or well remediation. API 1171 requires that storage operators perform periodic review and reassessment of the risk management process.

API 1171 requires operators to assess the risk of gas containment failure due to a number of causes including inadequate mechanical isolation caused by time-independent design features, construction/as-built features, material defects, material deficiencies and misapplications (inappropriate casing joint thread design, for example), or time-dependent decay of barriers due to corrosion, erosion, cement/cement bond degradation or disbondment, valve failure, gasket failure, etc.; loss of control while drilling, completing, or service interventions; third party actions; natural forces of earth systems – weather, ground movements, floods, etc.; and other causes.

Operators are advised to rank and prioritize risk and establish programs that prevent events by reducing the likelihood of the causes of gas containment failure and mitigate the consequences of a loss-of-containment event.

Throughout API 1171, operators are advised to use risk assessments to inform decision-making related to many integrity management practices.

CSA Z341.1 requires risk assessment (Clause 7.1) and provides guidelines for risk assessment in Appendix B. Similar to API 1171, CSA Appendix B emphasizes the use of risk assessment in decision-making regarding design, well construction and completion, location, operations, maintenance, monitoring, plugging, and site restoration.

ISO 16530-1 provides guidance on relating well integrity program task frequency to the risk identified in the operator's risk assessment.

Objectives and Contexts

The risk management process is a decision-making process. The first step requires clarification of objectives set into the external contexts of the operator's environment and the internal context of each operator's company.

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The primary objectives of each and every storage operator are 1) protecting human life, both of the public at large, locally in immediate areas of impact, and workers engaged in operations and support operations, 2) providing reliable service, 3) stewardship of the environment, and 4) the protection of property and financial resources. This four-fold aspect sets the fundamental, values-driven part of the gas storage operations objectives.

The operator defines the internal and external contexts of their storage operations and site specific contexts, the risk analysis method to use and the decision criteria.

Risk Source Identification

Operators identify the sources of risk – hazards, threats, and hazardous situations – that could affect the storage wells; then the operators identify the barriers and controls in place that prevent the risk sources from activating into events or that mitigate the consequences of events. Tables 1 and 2 in Section 8 of API 1171 provide a template of hazards and barriers/controls for operators to use when assessing site specific and company-specific risk sources and risk control programs.

Risk Analysis

Risk analysis estimates the likelihood of well failure and the likelihood-severity range of consequential impact.

The literature survey summarized in Appendix 2 provides ranges of well component failure modes and rates with and without ESV systems. Fault tree analyses in several studies have indicated up to an order of magnitude reduction in failure with subsurface safety valves installed, although when adding in the workover rates due to safety valve reliability, the overall rates of loss of containment with and without safety valves can be in the same order of magnitude.

The historical rate of significant well failures during operation is in the E-05 per well-year range, while loss-of-containment during well interventions is in the E-04 to E-05 range (per well entry). While the use of safety valves in the downhole environment can reduce likelihood of some failures if they occur uphole or downstream from the safety valve location, the failure rates with and without safety valves are in ranges described qualitatively as very unlikely (E-04 to E-05, as defined for hazardous process facilities by the Center for Chemical Process Safety (CCPS), American Institute of Chemical Engineers (AIChE); CCPS order of magnitude event frequencies align to qualitative descriptors: "extremely unlikely to remote" is <1E-05, "very unlikely" is in a range 1E-05 to 0.99E-03, "unlikely" is in a range 0.99E-03 to 0.99E-02, and "likely" is >1E-02).

The failure likelihood for which a subsurface safety valve is designed to protect against is "very unlikely," so that when the consequence potential also is small, the estimated risk without a subsurface safety valve almost surely will be acceptable, or tolerable with risk controls other than subsurface safety valves.

A storage operator can evaluate the likelihood for a well to have a loss-of-containment event on the basis of the well's as-built condition, including the number and quality of barriers such as casing, cement, or shut-off devices; on condition assessments of those barriers against operating conditions (casing integrity logs and the recency of the information, cement integrity logs, annulus pressure

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observations, pressure tests, function tests); maintenance, monitoring, and inspection of primary barriers and well conditions; and frequency and reasons to enter (intervene in) the well.

In events where safety, environment, and service reliability could be threatened, operators often take a precautionary approach – which says that when the chance of something happening is increasingly remote but the severity of the impact is potentially large, a cautious approach should be taken. The precautionary approach can be invoked when there is a need to focus the risk analysis on the consequence potential because of the number, density, and/or critical importance of potential receptors. Operators can identify receptors in a potential impact area and estimate the potential impacts those receptors could experience should a loss of containment event occur at a well. Operators can assess conditions which affect the likelihood of failure events and their escalation: the as-built condition of the well, the number of containment barriers and their state of integrity, the extent and competency of integrity monitoring, maintenance, testing, and verification plans, as well as the extent, competency and response capability of emergency action plans.

Consequence impact severity of a loss of containment event can be related to storage field or well deliverability at a casing-constrained open flow rate, the well count in a storage field, and each well's flow potential. Service reliability impact can be related to the consequence of taking the well and/or field out-of-service or changing the mode of operation due to an event. Safety consequences can be related to population density and proximity; environmental consequence impacts can be related to proximity to sensitive areas and the containment capability of an event's emission of fluid during/after an event.

Literature review indicates that distances of 75-100 feet (~30m) or less render high risk estimates for well failure impact on receptors, although the impact radius is dependent on the well's flow capability (SPE #145428, Powell and Van Scyoc, "Well Site Screening: The Critical Few" – see Appendix 2 for a summary). If a well has any significant pressure and flow capacity, there is potential to adversely impact people, property, and the environment within such a close range. Operators can analyze consequence impact severity for gradually increasing distances away from a well, basing the analysis on flow rate, potential duration, fluid composition, noise, odor and heat/fire potential.

Downhole loss of containment represents a specific failure scenario. Operators can estimate impact radius and severity related to downhole loss of containment and potential migration in subsurface zones. Subsurface migration potential can be related to production casing and cement quality and isolation capability, the presence of permeable pathways in the uphole geologic strata, and the pressure and volume drive from the well and reservoir.

The population density around a well and workforce engagement in activities at/in a well must be assessed. Population density and proximity can be assessed at two levels – within an operator's assessment of immediate and/or potential impact radius, and at a wider radius which might be affected under specific circumstances of a release, such as those with a long duration, significant release volume, and widespread impact due to noise, noxious odor, or underground release and transport. The radius of impact is generally taken to be a circular area, with the immediate impact radius defining an area where isolation and removal or close monitoring of receptors is necessary – an "immediate/initial isolation zone" or "IIZ." A potential impact radius is an area that could be impacted if changes in the circumstances of an event cause an escalation of the event; such circumstances could include duration, flow, secondary effects such as fire, odor, liquids, external effects such as atmospheric and weather conditions, and changes in receptors during the course of the event. The potential impact radius can be

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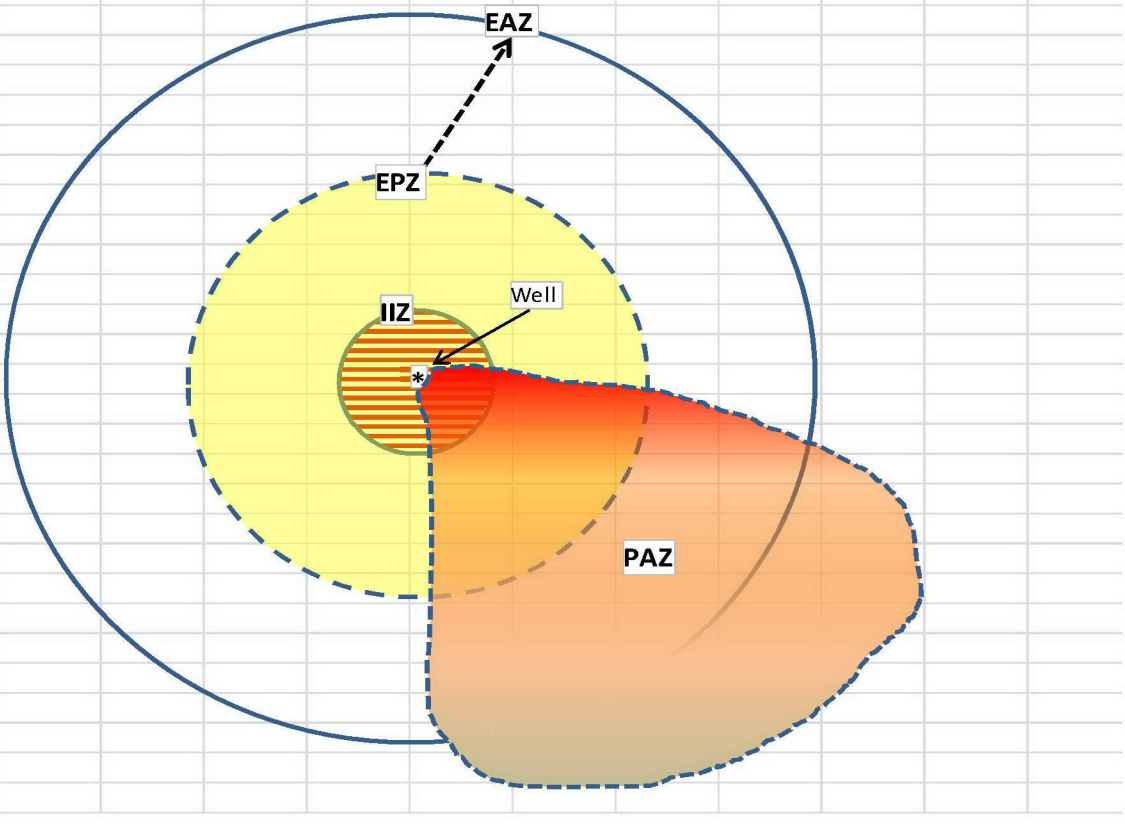
termed an “emergency planning zone,” or “EPZ.” An even wider radius of potential impact can be termed an “emergency awareness zone,” or “EAZ,” which is an area that could be impacted in specific events that include long duration, significant release volume, and widespread impact due to noise, noxious odor, or underground release and transport. During a specific event, conditions could be such that a protective action zone (“PAZ”) is determined for time- and condition-dependent factors, such as wind direction. The PAZ can change as influencing factors change, which requires operator awareness and incident command and control to set and communicate the emergency zones. The concept of a PAZ is that receptors inside the EPZ and/or EAZ might need specific protections or evacuations under special circumstances during a storage well release event. Storage operators can define the IIZ, EPZ, and EAZ, as illustrated conceptually below, for wells or groups of wells in their storage fields and describe in their emergency plans how these zones are determined.

Figure 3. Schematic of Storage Well Emergency Planning Zones. IIZ = Initial Isolation Zone, pre-defined; EPZ = Emergency Planning Zone, generally pre-defined and may expand to the EAZ = Emergency Awareness Zone. PAZ = Protective Action Zone, determined for time- and condition-dependent factors (wind, topography, etc.)



Site access for remedial and emergency equipment is a factor in the risk assessment. The ability to limit the consequences of a loss-of-containment event is evaluated by the operator on the basis of the emergency response plan quality (including training and readiness of the operator’s employees and contractors), the means of timely alert to or awareness of abnormal operating conditions at the well level (which requires the setting of well operating limits for pressure, flow, temperature, and annular conditions and then monitoring with those limits in mind), the ability to control the well via interventionist means (rather than by component means such as automatic or manual valves or reliefs),

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and the time required to respond to an abnormal condition or a loss of containment condition and bring the well integrity back to a state of gas containment.

The added risk created by installation and servicing requirements relative to well equipment, such as the ESV system, should be analyzed. The installation of a subsurface safety valve carries a burden of well intervention to service the valve when it fails. The failure rate for safety valve systems can be estimated from operator testimonials and literature review. Much of the literature uses a data set from the offshore world. The operator testimonials add to existing literature and establish ranges of reliability and well re-entry frequency in the natural gas storage world.

Evaluation of Risk

The storage operator's evaluation criteria is used to rank and prioritize wells identified as having significant risks in the analysis step, and if necessary a further analysis and comparison can be conducted for decisions on use of an ESV system or alternative risk controls.

Storage operators have made many decisions regarding the installation and maintenance of ESV systems. Consensus decision-making has seen very few new installations of subsurface safety valves but somewhat a trend to replacing subsurface valves with surface safety valves. Operators have made decisions on ESV system use in complex, well-specific applications given the full range of site-specific risk inputs set against objectives of protecting people, property, and the environment, and protecting the workforce that must engage in well interventions and maintain service reliability.

It is the nature of risk management decisions that uncertainty remains after decisions are made. Storage operators can monitor the reliability of their storage wells, particularly those wells that have a surface or subsurface safety valve. Reliability information could be shared among operators in a uniform, consistent format so that a body of information could be assembled for learning and continual improvement in safety and reliability. The factors to which the risk analysis is most sensitive might be clarified, and, where appropriate, those same factors could be subjected to reliability improvement techniques.

Risk Treatment Alternatives

ESV systems are designed to activate in the event of a loss of containment or abnormal condition of flow, pressure differential, or variation in control energy. ESV systems are consequence mitigation devices and their effectiveness and value can be compared to alternative risk reduction measures.

The likelihood of a loss of containment event can be reduced by decreasing event initiator potential and/or increasing the redundancy of preventive barriers. The potential consequences of a loss of containment event can be reduced by employing mitigation barriers that reduce the duration and/or magnitude of the event. This section describes a number of alternatives to risk reduction. Operator data can be collected and analyzed to assess the effectiveness of alternative risk reduction measures, the reliability of risk reduction systems, and any new risk that might be introduced by each alternative.

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Preventive Measures

Storage operators can employ protections to wellhead or near-wellhead pipe to prevent access and prevent vehicular collisions and animal and human interference. Surface methods can include installation of SSV on the wellhead or at the wing of the wellhead.

Operators could add downhole barriers or increase the robustness of existing downhole barriers if feasible, in order to add layers of protection so that if one barrier decays or fails, a second barrier exists to prevent loss of containment. Figures 4 and 5 show the concepts of barriers and the risk reduction by use of redundant barriers. Addition of tubing set into an isolation packer adds a layer of protection but restricts cross-sectional flow area.

Operators can assess the potential for successful addition of cement and advanced formation sealers in the area behind the casing. Cement can be added behind casing where it was not originally placed if deemed practical and cost-efficient. Remedial cementing could increase the amount of cement behind primary casing through perforating the casing and cementing, milling windows in the casing and cementing, or cutting and pulling free old casing and then inserting new liners and cementing the liners in place with a full cement sheath. When successful, such placement strengthens the cement sheath as a barrier to flow and as a next barrier to loss of containment should the casing fail. However, remedial cementing using these methods impairs the primary casing string by putting holes in the pipe, which must then be sealed. The impairment of the casing creates a new risk and the sealing method must be assured, or another barrier installed, such as a liner or tubing on an isolation packer or a liner cemented inside the casing.

Most of the options that increase the number and/or robustness of downhole barriers have an attendant reduction in cross-sectional flow area, which could lead to a need to drill additional wells to provide the same storage service capacity and reliability. All options, except those for liners cemented in place and cement additions, decrease reliability over the operating life cycle due to the introduction of additional mechanical components. The remedial or barrier addition options also can prevent or decrease the ease of use of other barrier monitoring tools such as casing inspection and fluid movement monitoring devices.

Passive physical barriers such as casing (liners) and cement have inherent reliability in that they are designed to function all the time to contain the stored gas and prevent back-side fluid movement. Storage operators can monitor the condition and effectiveness of the passive physical barriers to monitor the effects of time- and service-dependent decay modes.

Figure 4. Schematic Example of Single Barrier and Multi-Barrier Wellbore

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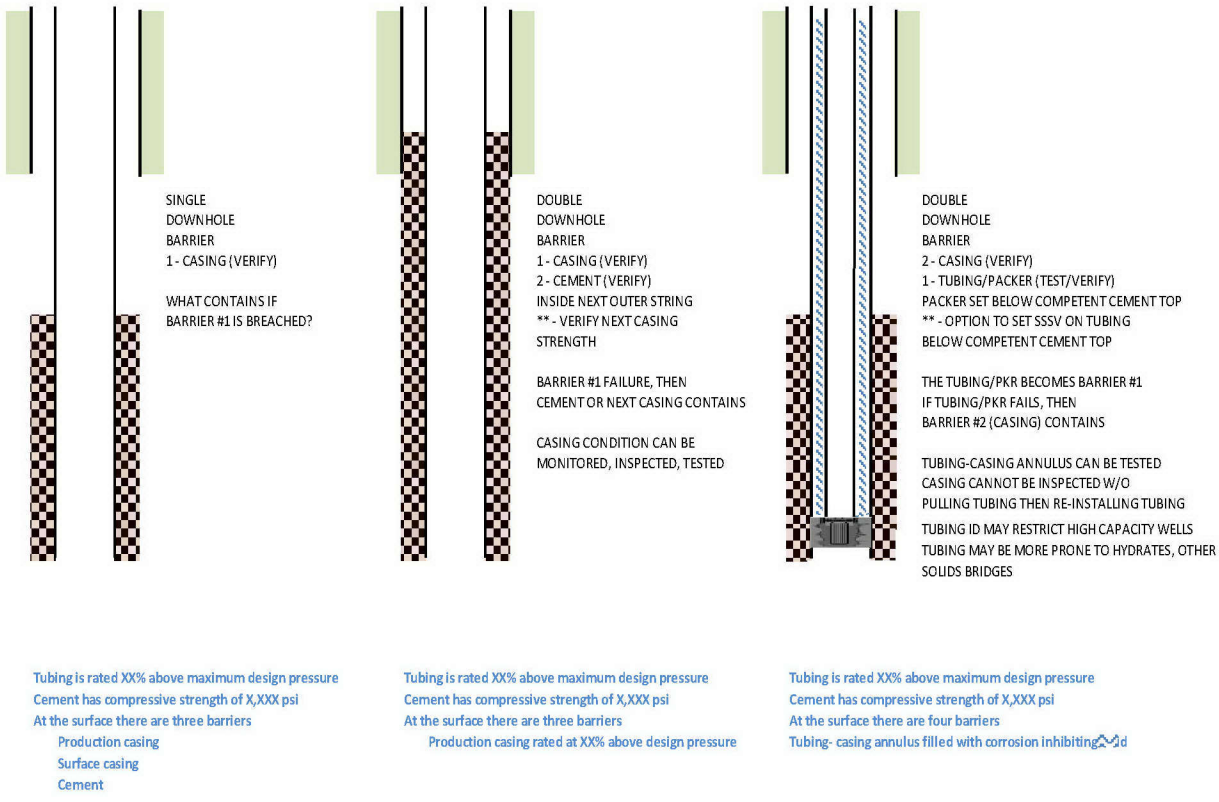
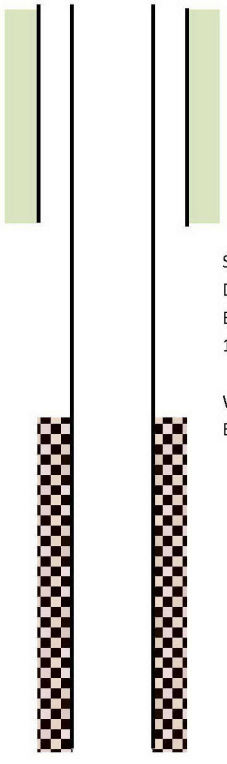


Figure 5. Example Risk Assessment Outline, Single Barrier Well



SINGLE
DOWNHOLE
BARRIER
1 - CASING (VERIFY)

WHAT CONTAINS IF
BARRIER #1 IS BREACHED?

RISK ASSESSMENT

IDENTIFY SINGLE BARRIER WELLS

IDENTIFY PROXIMITY TO DWELLINGS, PUBLIC ASSEMBLY PLACES, SENSITIVE AREAS
- RANK IMPACT POTENTIAL
- HEAT RADIUS POTENTIAL

IDENTIFY POTENTIAL FLOW PATHS
- DOWNHOLE MIGRATION VIA POROSITY, FRACTURES, DRILL PATHS

IDENTIFY FLOW POTENTIAL
- PRESSURE, RATE, SUSTAINABILITY (1, 7, 15+ DAY VOLUME)

ASSESS CASING CONDITION
- INSPECTIONS, SURVEYS, TESTS, RECENCY

ASSESS OPERATOR INTEGRITY AWARENESS AND CAPABILITY
- MONITORING, TESTING, DATA COLLECTION PROGRAMS
- PROCEDURAL ACUMEN AND COMPETENCY/READINESS
- EMERGENCY PREPAREDNESS
- COMMUNICATION AND COMMAND/CONTROL CAPABILITY
- RESPONSE TIME CAPABILITY

ASSESS RECONFIGURATION OPTIONS AND VIABILITY

ASSESS ALTERNATIVE PROTECTION MEASURES
- PREVENTIVE
- MITIGATION

ASSESS RISK REDUCTION/RISK INCREASE OF ALTERNATIVES

DEVELOP SHORT AND LONG TERM RISK MANAGEMENT PLAN FOR SINGLE BARRIER WELLS

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Monitoring, inspection, and testing of well barriers, using methods such as those described below, can reduce the likelihood of events by providing operators with information on barrier condition and effectiveness. Certain techniques requiring well intervention – the insertion of devices in a pressure-bearing well – come with the ever-present risk of loss-of-well-control.

Casing inspection logging with magnetic flux leakage tools can provide information on baseline casing condition and changes in casing condition by repeat surveys thereafter over the well life cycle. Casing condition affected by internal or external corrosion or mechanical wear events can be identified in such surveys. Ultra-sonic tools also can be useful in assessing casing condition and detecting certain anomalies. Operators generally look for consistency of methods over the course of time as each method of casing inspection has some weaknesses. Casing condition affected by significant earth movement events could be revealed by some types of casing inspection surveys such as internal calipers or downhole video surveys, if there is reasonable before- and after-event comparison capability.

Fluid analysis for chemical composition, microbial activity, and acid gases and water assist operators in understanding the corrosion potential of the well fluids and designing corrosion monitoring and mitigation programs. Ultra-sonic pipe wall thickness sensors can be used in above grade piping adjacent to wellhead to check for metal loss; this method is non-invasive and thus has no impact on deliverability or reliability.

Cement integrity surveys, typically with sonic-based tools, can verify the extent and fluid isolation potential of the cement sheath around the casing. Operators lacking knowledge of the cement condition can acquire this information as a means of performing well integrity assessments necessary to risk-based decisions.

Consequence Mitigation

The installation of an SSSV adds a downhole barrier designed to respond to an event, and thus by definition an SSSV is a consequence mitigation barrier. The SSSV activates in response to significant changes in pressure or flow or loss of hydraulic or pneumatic control - events that have a high threshold of deviation from the norm. For small deviations, it is possible, and in fact very likely, for the SSSV to not activate, as for example in the case of a well leak through a pin-hole or small corrosion or mechanical defect feature. The SSSV installation system can reduce cross-sectional flow area and increase the number of service interventions over the life of the well. Consequence mitigation by the SSSV is ineffective in a well where the loss of containment is below the valve or where the valve failed to function. Flexibility of well intervention is decreased by the presence of the SSSV. Kill options might be reduced due to the position of the SSSV and its cross-sectional flow area. The presence of the SSSV system could increase risk in the well intervention operations due to the additional tubing, the valve, and control lines. In the event any of the system is caught in the wellhead during an incident, the master gate valve might not function properly and the event intensity and duration could increase.

Flow and pressure monitoring at the wellhead, including annulus pressure monitoring, is an effective means of detecting abnormal operating conditions. Downhole pressure-temperature devices can be installed in wells to provide additional direct measurement closer to the reservoir; near-reservoir level monitoring could be a valuable addition to wellhead pressure and temperature monitoring in certain wells where significant pressure and temperature changes occur along the length of the well profile. A storage operator's pressure and flow monitoring program and training of staff to awareness of and

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response to abnormal operating conditions is a consequence mitigation measure that can be highly effective in minimizing the impact of an event. Early detection of events and efficient response to events is essential to minimizing escalation and thus limiting consequences. Setting of well operating limits and monitoring and inspection of well operating conditions such as pressure, temperature, and flow rate are critical to detection of abnormal conditions to which a response should be given. Operators can assess the consequence mitigation value of data gathering and requirements and training around review of the data and actions in response to abnormalities relative to well operating conditions. Operators can make risk-informed decisions on changes to their program of data gathering and staff training in order to focus resources in the most necessary places and increase process safety reliability.

Well intervention in response to a loss-of-containment event is often practical in many wells and serves to mitigate consequences when the well can be safely entered. A full discussion of well intervention methods and safe work practices is not the intent of this Appendix. However a quick listing of potential intervention methods includes isolation of pressure and flow by setting downhole plugs by electric line or coiled tubing, killing the well by pumping fluid from the surface or through coiled tubing, or through a working tubing string snubbed into the well. In some wells, a deep-set packer can offer the opportunity to set a wireline plug to isolate the reservoir from the well above the packer set point. The deep-set packer system provides a benefit to entry and isolation of a well using a small diameter plug, smaller than the casing internal diameter, where the wellbore internal diameter might be restricted due to casing deformation or buildup of organic or inorganic scales and bridging materials that might preclude a full-bore plug from being set in the casing. Once the well is in a state of control it is possible to conduct additional work to investigate the loss of containment and begin remedial work.

A developed and tested emergency response plan that specifically addresses potential loss of containment events in storage wells during normal operation and during well drilling, servicing, or intervention is necessary to consequence mitigation. Operator emergency response plans should include definition of roles and responsibilities within an incident command structure, the communication and coordination with civil emergency responders, contractors and emergency response material sources, and assistance or coordination with industry partners who could be helpful if an event occurred. Operator personnel are expected to be familiar with the plan and trained in its application.

Emergency preparedness planning links to well integrity documentation. Well integrity assessments allow operators to document as-built and as-current conditions and provide information to the operator necessary for risk-informed decisions. Well integrity loss-of-containment incidents require decisions on whether or not to take the well out of service, repair the well, or plug and abandon the well. In the absence of loss of containment events, well integrity assessments help operators allocate risk management resources on those wells ranked highest in risk. Operators can focus well integrity assessment on wells within a specifically determined radius of places of habitation, roads, human gathering places, or environmentally sensitive areas. Operators can develop risk management plans for wells defined in the integrity assessments as located within a significant impact radius potential of receptors and with capacity to flow at high rates and/or long durations.

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Section 6. Summary

Conclusions

The natural gas storage industry has experience using various forms of ESVs. This Appendix provides testimonials from five companies with thousands of operating well-years with ESVs and in total almost 200,000 operating well-years. The overall record of safety in terms of loss of containment events is in the frequency range described as "very unlikely."

Natural gas storage operators focus their well integrity efforts on the condition and effectiveness of the inherently reliable passive technical barriers of casing and cement. Operators can define as-built, as-identified conditions of barriers and define the limits of pressure and flow under which wells should be operated and monitored. Condition assessment of casing and cement are critical to ongoing integrity management. Installation of additional downhole equipment can impede or make more difficult the condition assessments of casing and cement.

A number of natural gas storage operators have used and still employ both SSV and SSSV. The use of either surface or subsurface ESV systems is an operator-based decision made in view of a wide variety of site-specific factors. Industry sources indicate that installation of a SSSV might decrease the risk by nearly an order of magnitude as compared to the risk due to failure of a primary barrier, such as casing. However, the effectiveness of an SSSV as an additional downhole barrier depends on its location and what the valve location is designed to protect or limit; the effectiveness of an SSSV also depends on the valve system reliability and the valve actuation potential against the potential created by an actual event.

SSSV reliability issues can increase potential for loss of containment events due to the well re-entry to pull and repair or replace the valve. Industry literature cited herein supports the company testimonies with respect to SSSV reliability issues. The reliability issues with SSSV detract from the risk reduction benefit gained by adding SSSV as a downhole barrier.

Storage operator testimony suggests SSSV systems have had, in some wells, adverse consequences on flow capacity and flow reliability, due to the flow profile restrictions that are part of the design of the valves and/or of the valve installation system.

The natural gas storage industry focuses on the values of safety, environmental stewardship and service reliability. Operators are expected to conform to API 1170 and API 1171 standards with respect to decision-making on use of ESVs. API 1170 and 1171 were developed by a consortium including state and federal regulatory agency representatives and some of the most knowledgeable natural gas professionals in the industry. The authors expect that the API 1170 and 1171 practices will be applied across the industry while recognizing the need for unique solutions because of the geological diversity, operator experience, and historical context.

The authors align with the recommendations made in PHMSA's Storage Advisory, Docket No. PHMSA–2016–0016: Safe Operations of Underground Storage Facilities for Natural Gas, with respect to decision-making around the use of ESV or alternatives. Specifically, the PHMSA advisory bullet #4 recommends periodic function tests for all ESV systems and the repair of deficiencies and failures, or the removal of the well from service, or employment of alternative and equivalently effective safety measures. PHMSA

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advisory bullet #5 recommends that operators evaluate the need for subsurface safety valves on new, removed, or replaced tubing strings or production casing using risk assessment aligning to API 1171 criteria as a minimum, and that where subsurface safety valves are not installed, the operator use the risk assessment to inform decisions on integrity inspection frequencies, reassessment intervals, and well integrity issue or incident mitigation criteria.

Further the PHMSA advisory recommends that storage operators implement API 1170 and API 1171, and the Interstate Oil and Gas Compact Commission's (IOGCC) Natural Gas Storage in Salt Caverns—A Guide for State Regulators (IOGCC Guide). Developed under a joint effort of regulators and industry, API 1170 and API 1171 are based on the premise that well life cycle integrity management requires good design, construction and operating practices. For the operations life cycle stage, site-specific risk assessments and integrity program and plan inspection, monitoring, testing and well intervention and remediation tasks are to be based on the operator's risk assessments, knowledge, experience and skill.

Recommendations for Continual Improvement Actions

The risk assessment, decision and rationale regarding application or potential application of an ESV system on a natural gas storage well in a depleted hydrocarbon or aquifer reservoir is a duty of a storage operator under the requirements of API 1171, Clause 6.2.5. The authors highlight the risk management process recommended to operators for use in the decision-making processes. Good decision making is transparent and assesses the outcomes of past decisions.

The authors recommend that storage operators engage in the following continual improvement actions:

- ✓ Follow the risk management process and minimum evaluation requirements in API 1171, Section 8, and clause 6.2.5, and share lessons learned and good practices through industry associations;
- ✓ Follow the additional guidance around risk management discussed in this Appendix and establish a consensus as to some uniform, minimum risk management process detail;
- ✓ Develop templates and methods to gather and share information regarding reliability of various well barrier element system components, including surface and subsurface ESV systems;
- ✓ Establish partnerships between operator groups and stakeholder groups to evaluate reliability of ESV systems and system components, with goals to establish, evaluate, and report safety performance, and develop guidelines for good practices in integrity management and ESV system reliability management; and
- ✓ Collaborate through industry associations and regulatory agencies to develop common integrity management goals and establish regular forums where operating experiences can be shared and employee knowledge, skills, and experiences can be developed and enhanced.

APPENDIX 6.1. COMPANY EXPERIENCES AND OBSERVATION WITH RESPECT TO ESVs

The company testimonies represented in this Appendix are from five storage operators with a combined experience of nearly 200,000 well-years of operation and over 5000 well-years of operation of

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subsurface safety valves. The five-company operator group represents a set of 68 depleted reservoir storage fields with over 3,400 wells, of which approximately 200 have subsurface safety valves and more than 200 have surface safety valves. The wells in this group represent operating pressures ranging from 200 psig to 4,000 psig and maximum flow rate potential of up to 500 MMcf/d.

Company A

Basic Statistics:

Of Company A's wells, nine percent have shallow, hydraulic surface controlled subsurface shut-off valves (SCSSV) and 15 percent of wellhead mains or their wing assemblies are pneumatically controlled by surface shut-off valves.

Brief Underground Storage History

Company A operates gas storage facilities in depleted reservoirs, aquifers, and salt caverns in conformance with all state and federal regulatory requirements. Several of the depleted reservoirs had subsurface shut off valves installed while in production service. As the fields, dating from the 1950s to 1980s, were converted to gas storage service and new wells were added, new surface controlled subsurface shut-off valves (SCSSVs) aka "disaster valves" or "downhole safety valves" (DHSV) were installed as a matter of conformity to past practices and because the term "safety" seemed to suggest a level of prudency. However, within a few years of installation, many of the subsurface shut off valves began to fail for a variety of reasons including but not limited to: sticking mechanisms, leaking hydraulic pumps and lines, control panel leaks, bad regulators, failed seals and flapper valves becoming stuck in open, closed, or partially open positions.

Company A's ongoing decisions to employ subsurface "safety," more aptly "shut-off" valves, are influenced by its risk assessments and experience with the reliability of DHSV systems. The valves are typically complex sliding or flapper devices, some consisting of more than 100 components, as shown in Figure 1, with tight clearances that can be contaminated, clogged, degraded, and worn, resulting in hydraulic leaks and valve failures. Because of reliability concerns, DHSV valves are no longer installed as a normal practice in new wells, and they are removed from existing wells when maintenance allows.

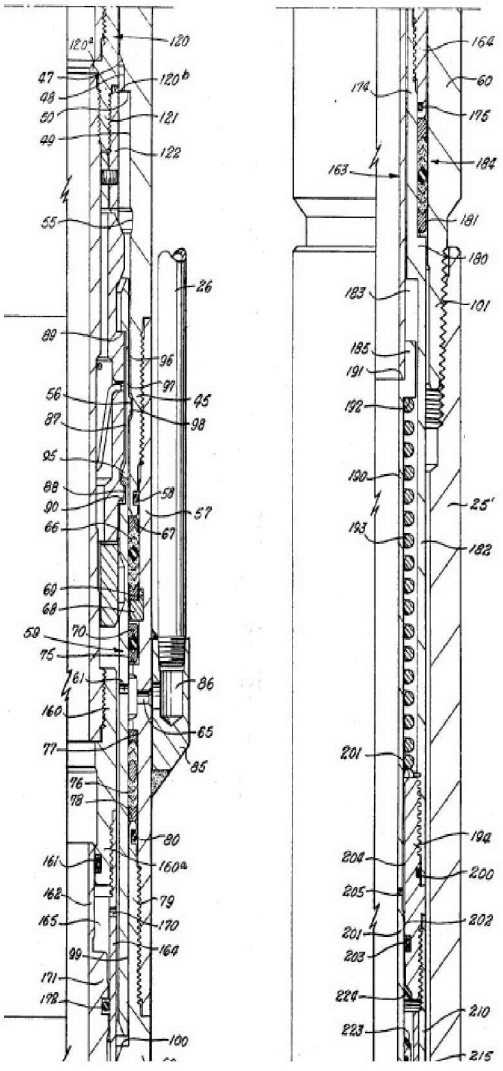

Figure 1. Disaster Valve US Patent 3874634

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Reliability

Company A has experienced numerous DHSV failures across multiple storage companies using different manufacturer's subsurface shut-off valves. Company A's experience has been that the reduction in flow area through the valve presents an opportunity for hydrates, paraffin, salts, or other solids to build-up resulting in failure of the SCSSV. Additionally, there have been reliability issues with shut-off valve control line system hydraulics resulting in false closures, blockage of flow, and damage to inspection tools used for assessing well integrity. More than 50 percent of the SCSSVs originally installed in Company A's fields, over the lifetime of the well, experienced a reliability issue and have been removed or locked open for further analyses because a failure of the valve and/or its ancillary systems could have significant negative impact on gas deliverability during a critical period of market need.

Safety

SSSVs used in gas storage originated from the valves installed in subsea production wells where underwater mud slides could shear off the wellhead. SSSVs were believed to provide a fail-safe means of shutting in the gas storage well and isolating the conduit to the reservoir from any surface disaster, including complete shearing off of the wellhead assembly.

In the more than 40 years that Company A has been operating wells with SSSV assemblies, its gas storage fields have not experienced shearing at the wellhead. The majority of the wells are far from the roadway so that the threat of high-speed vehicular collision with a wellhead is remote. Collision risk events can be prevented by installing anchored fencing or guard/buttress systems.

Integrity

A risk related to DHSV/SCSSVs is from normal maintenance operations related to servicing the downhole valves themselves and the need to remove and re-install the valves due to other well work, such as casing inspections. The pressures that must be contained while removing the DHSV from a storage well range from hundreds to thousands of pounds per square inch, resulting in a force capable of launching heavy equipment into the air. Thus, working on a DHSV to maintain its integrity and reliability presents a level of risk that should be carefully considered.

DHSV/SCSSVs fit within the gas well casing and restrict the flow area reducing deliverability. This means wells with SCSSVs cannot be controlled with conventional plugs. In order to be inspected, deep DHSVs require the removal of thousands of feet of tubing while the well is under pressure. The risks during well work, and the restriction caused by the DHSV, and the additional methane that is released to remove and service the DHSV, are all factors that must be carefully considered before installing a DHSV.

Conclusion

Company A has been proactively analyzing its well integrity and removing failed DHSV/SCSSVs not only to prevent a catastrophic loss of gas deliverability to the market place, including residential heating and power plants during critical periods of need, but also to increase safety during work and maintenance to reduce methane emissions. Company A believes it is better to focus on gas well integrity rather than install valves downhole that in all likelihood will never be used and can actually increase the risk of an incident during well interventions.

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Company C

Of Company C's portfolio, three percent of wells have hydraulically surface-controlled subsurface safety valves, and the majority of which are deep set and the rest are shallow set pusher type; additionally, one percent of wells have pneumatically controlled surface ESD valves.

Safety valves have been in service 10-30 years. Safety valves in service are in wells within a several hundred foot proximity to residences, businesses or schools. Company C had several safety valves in one field in the past due to coal mining. Decisions were made to plug these wells and not drill and complete future wells unless they are drilled through a pillar. Company C has had subsurface safety valves close due to control line leaks.

Subsurface safety valves in these storage wells drastically reduce flow by 40-50 percent, but the company has not noticed reduction in flow through wells with surface ESD valves.

The company decided to use concrete and or steel barriers around wells where necessary to reduce risk, as alternatives to safety valves.

Brief Underground Storage History

Company C operates storage facilities in depleted reservoirs, aquifers, and salt caverns in conformance with all state and federal regulatory requirements. Several of the reservoirs had SSSVs installed due to proximity to residences, schools, or were in an underground coal mining area. Safety valves are tested once a year to assure that SSSV will close and then are pumped open again. Most failures have occurred due to surface control failure. All storage wells are on a regular workover schedule which includes casing inspection logs. Each storage well has at least two casing inspection logs in its history. Wells are serviced every 10-15 years. The company has experienced one serious well control incident in the last 50 years.

Safety

The majority of Company C wells are in remote areas and it is the Company's assessment that SSSV are not warranted. Wells in fields with animals have either pipe or concrete barricades around the well. Generally 50% of the wells have either a safety valve or barrier around the well.

Company E

Basic Statistics:

Company E operates numerous depleted storage reservoirs, where approximately 2.5 percent of wells have shallow-set surface-controlled subsurface safety valves (SCSSVs), which are hydraulically controlled and approximately eight percent have surface-controlled surface safety valves (SCSVs) with a fusible element, which are hydraulically controlled and located in the wellhead stack (spring-actuated, fail closed design).

Brief Underground Storage History

Company E operates storage facilities in depleted reservoirs in conformance with all state and federal regulatory requirements. Several of the depleted reservoirs had SCSSVs installed while in original

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production or conversion to storage operations once the fields were depleted. The remaining SCSSVs date from the late 1960s to early 1970s, with the exception of two valves which were installed in the mid-1990s. As the fields were converted to gas storage service and new wells were added, new subsurface control subsurface safety valves were generally installed as risk mitigation to wells within the flight path of neighboring aircraft. However, within a few years of installation, many of the subsurface safety valves began to fail for a variety of reasons, including increased corrosion of valve, materials plugging the valve bore, and reliability with the hydraulic control and tubing system used to control the valves.

Risk Basis for Safety Valve Installation:
Company E's current risk assessment considers the principles of API 1171 requirements, using the following factors in evaluating the potential applicability of any type of safety valve:

Flow potential of the well at maximum reservoir pressure

Proximity of the well to:

- ✓ People in permanent dwellings
- ✓ People in public gathering places
- ✓ Probable frequency/density of people in recreational areas
- ✓ Transportation corridors, public or private, including air, roads, rail, waterways
- ✓ Environmentally sensitive areas
- ✓ Other storage wells, storage infrastructure, or other industrial infrastructure
- ✓ Ability to control the well through fluid pumping (well kill) or other interventions
- ✓ Safety valve reliability experience and safety risk to well service personnel engaging in well interventions

Company E views safety valves as a mitigative measure in the event of a significant sudden failure of the gathering lines, the near-well flow line or other equipment adjacent to the wellhead. Casing failures at depth are possible but the event likelihood is remote, in the 1x10E-4 to 1x10E-5 range (published literature). Company E operates in a region where forces causing induced stress on wells and casing are remote, leaving human causes as the main influence in well operation / catastrophic failure potential.

Of all the analytical factors, the proximity of the well to potential heat-affected radius (which is a result of maximum flow rate) are the most heavily weighted factors in decisions on whether to employ a safety valve.

Reliability:
Company E has experienced numerous failures with the same manufacturer's subsurface safety valves. Experience indicates a reduction in flow area through the valve presents an opportunity for hydrates, paraffin, salts, or other solids to build-up. The build-up may result in a failure of the SCSSV to operate as designed. Additionally there are reliability issues with safety valve control systems and hydraulics resulting in false closures.

Company E has documented valve malfunctions and test failures, and those failures necessitated additional well interventions.

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Safety:
The SCSSVs systems were originally installed to provide a fail-safe means of shutting in the well and isolating the conduit to the reservoir from any surface disaster, including complete shearing off of the wellhead assembly.

In the nearly 50 years that Company E has been operating wells with SCSSVs, the system has never experienced an incident which threatened a violent shearing at the wellhead. The majority of the wells are not located near roadways, so the threat of high-speed vehicular collision with a wellhead is remote. A majority of these wells are protected against collision by a guard rail. The wells do not exist in a high-risk earthquake or earth shear zone. Some wells do exist proximal to flight paths of heavy and/or high speed aircraft, but the probability of occurrence is remote. Likewise, sabotage or terrorist acts could target wellheads, but individual wells can be considered at low risk of being targeted due to their distance from the general public and due to the choices of easier targets.

The biggest risk with SCSSVs is from remedial operations related to servicing the safety valves themselves or the need to remove and re-install the valves due to other well work, such as casing inspections. This is noted extensively in the professional literature.

If the risk of well incident or worker injury is present every time a valve is retrieved and reinstalled, then company personnel have had several hundred well intervention events in their operating history where an incident could have happened. In the same time frame, the company is aware of three insignificant collisions with a wellhead in the system (light duty trucks and farm equipment). The company has never experienced plane crashes or terrorist events at or near any wellhead. The company's experience and knowledge of similar operators' experiences mimics professional literature, in that risks during well intervention are significantly more likely to create an incident than shearing of a wellhead.

During the 1990s, Company E reached a point where about 10% of wells had SCSSVs. Nearly 75% of the SCSSVs have subsequently been removed since the mid-1990s. The SCSSVs were originally removed during corresponding well interventions, but a specific program to actively remove the SCSSVs and replace them with SCSVs was initiated in the early 2000s.

Company J

Basic Statistics and History:
Company J operates a relatively small fleet of wells but approximately 30 percent of wells have SCSSV.

Reliability:
Company J has experienced multiple problems with subsurface safety valves installed in the 1980's. As Company J did not keep detailed logs of SSSV maintenance prior to 2016, Company J cannot substantiate if the failed SSSVs were properly maintained per the manufacturer's specifications.

- In testing and maintaining SSSVs, Company J has documented eight valve test failures. These failures were not limited to one facility or location.
- Company J currently has seven SSSVs that it has decided not to test or operate as Company J has observed similar SSSVs fail in a closed position. Company J highly believes that a significant

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percentage would fail closed if operated and would require an immediate wireline job to reopen the SSSV to operate the well.

- Company J plans to remove SSSV from two wells and not reinstall or replace the valves.
- Company J has observed reliability issues with safety valve control line system hydraulics resulting in false closures, and flow restrictions.

Safety:
SSSVs were installed to prevent a loss of containment and provide an additional shut-in mechanism at the wellhead.

- In its operating history, no Company J wellhead has been sheared. No incidents or near misses that could have caused wellhead shearing.
- The majority of Company J's storage fields are in remote or rural locations away from densely populated areas and major roads.
- Placement of SSSVs is along roadways and structures intended for human occupancy.

Subsurface safety valves are not a panacea as they can complicate operations, may limit tubing inspection options, and require additional maintenance.

Company S

Basic Statistics:
In Company S' portfolio, 12 percent of wells have shallow-set surface-controlled subsurface safety valves, hydraulically controlled, three percent have surface safety valves, pneumatically controlled, on the wellhead and/or at the immediate wing of the wellhead.

Risk Basis for Safety Valve Installation:
Company S' risk assessment follows the principle of API 1171 requirements (at Section 6.2.5), using the following factors in evaluating the potential applicability of any type of safety valve:

Flow potential of the well at maximum reservoir pressure

Reservoir storage volume and depletion rate potential

Proximity of the well to:

- People in permanent dwellings – immediate radius
- People in public gathering places – immediate radius
- Probable frequency/density of people in recreational areas
- Transportation corridors, public or private, including air, roads, rail, waterways – immediate radius
- Environmentally sensitive areas – immediate radius
- Other storage wells, storage infrastructure, or other industrial infrastructure
- Population density in a wider (three to five mile) radius

Ability to control the well through fluid pumping (well kill) or other interventions

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Safety valve reliability experience and safety risk to well service personnel engaging in well interventions

Fluid composition – range of gas composition, liquid hydrocarbon potential, freshwater potential, saltwater potential

Well construction (as built, current state), including number and quality of casing and cement sheath barriers, and the casing geometry (diameter, inclination, depth)

Company S views safety valves as consequence reduction controls in the event of a significant sudden failure of the gathering lines, the near-well flow line or other equipment, the wellhead, or a near-surface (shallow-depth) casing rupture or shear. Casing failures at depth are possible but the event likelihood is remote, in the 1x10E-4 to 1x10E-5 range (company experience and published literature). Casing failures with apertures large enough to have significant flow rates must be induced by human or natural forces that place increased tensile, compression, or axial force on casing, which might be weakened by time-related degradation mechanisms such as corrosion. Drawing on the extensive operating history in the areas where Company S operates, Company S knows that natural forces causing induced stress are rare, leaving human causes as the main influence in well operation/catastrophic failure potential.

Likelihood analysis (of a large rupture) is driven by the as built/current state of the well and the well's proximity to strike impact or potential stress-inducing forces.

Consequence analysis is driven by well potential, reservoir volume and rate of pressure depletion, proximity to sensitive receptors (people, environment, other infrastructure, particularly in an immediate radius affected by heat stress and ignition potential should an uncontrolled well flow ignite), and fluid composition, and consequence reduction measures including kill potential, emergency preparedness and anticipated effectiveness of emergency response measures including response time and perceived well controllability.

Of all the analytical factors, the proximity of the well to impact receptors or impact deliveries and the potential heat-affected radius (which is a result of maximum flow rate) are the most heavily weighted factors in decisions on whether to employ a safety valve.

Company S' ongoing decisions to employ safety valves is influenced by its experience in the reliability of safety valve systems.

Reliability:
Reliability is expressed in valve function failure during normal operation, or valve failure during semi-annual function tests. Experience has been that the upper assembly creates a restriction that is a favorite hydrate, paraffin, salt, or other solids bridging area, leading to decreased reliability and time and expense involved in finding and remediating the bridging. There have been reliability issues with safety valve control line system hydraulics and false closures due to control line leaks or temperature changes.

Company S has seen valve malfunctions and test failures at a rate of one to two percent of all valves in inventory per year (0.015 failures per well-year of operation).

The total entry-and-removal/replacement of subsurface safety valves has a rate of 0.141 entries per well-year, composed of 0.047 entries per well-year for SV inspection and repair, 0.015 per well-year for

test/function failures, and 0.079 per well-year for casing inspection. Thus, the reliability issue reasons for re-entry are ~0.062 entries per well-year.

The total re-entry rate is a significant factor in the safety impact analysis used in decision-making around safety valve disposition.

In addition to well re-entry to pull the valves, Company S has tracked flow and function reliability issues related to downhole safety valves for the period 2005-2016. Flow and function reliability issues include hydrates, salt, or paraffin bridging in the safety valve assembly, or function test failures due to the same types of bridging agents fouling the flapper closure mechanisms. Although 2016 represents a partial year thus far, the corrective maintenance issue (reliability issue) rate is 0.151 per well-year of operation. Company S observes that the annual corrective maintenance rate varies from as low as 0.061 per well-year in warm, small-withdrawal volume winters to 0.224-0.293 per well year in cold, deep-withdrawal winters. The overwhelming majority of corrective maintenance actions involve flushing with solvents such as water, methanol, or heated diesel oil, and in over 90 percent of instances these are successful in restoring flow and proper valve function.

Safety:

The SSSV systems were installed in order to provide a fail-safe means of shutting in the well and isolating the conduit to the reservoir from any surface disaster, including complete shearing off of the wellhead assembly.

In the more than 36 years that Company S has been operating wells with SSSV assemblies, the system has never experienced an incident that approximated or threatened a violent shearing at the wellhead. The majority of the wells are far from any roadway so that the real threat of high-speed vehicular collision with a wellhead is extremely remote, and such an event can be protected against via anchored fencing or guard/buttress systems. The wells do not exist in a high-risk earthquake or earth shear zone. Certain wells do exist more proximal to flight paths of heavy and/or high speed aircraft; although a well blowout from a plane crash is protected against with a SSSV given the depth of setting, such events have a very low probability of occurring. Likewise, terrorist acts could take out wellheads, but individual wells can be considered at low risk of being targeted due to their distance from the general public and due to the choices of easier targets.

The biggest risk related to surface-controlled subsurface safety valves is from remedial operations related to servicing the safety valves themselves or the need to remove and re-install the valves due to other well work, such as casing inspections, and this has been noted over the years in the professional literature. For example, a 1985 Journal of Petroleum Technology (JPT) article ("Subsurface Safety Valves: Safety Asset or Safety Liability?", Busch, Policky, Llewelyn, JPT October 1985) quoted a survey of well blowouts from 1979-1982 (in the non-communist world). Of the 271 blowouts, 216 were blowouts while drilling and 55 were production related. For the production related blowouts, the largest percentage (14 of 55) occurred during workover operations.

If the risk of well incident or worker injury is present every time an upper assembly is retrieved and reinstalled, then Company S has had several hundred well intervention events in the past 36 years where something could have happened. The Company S experience and knowledge of similar operators' experiences mimics that reflected in the literature, which is that risks during well intervention

are more likely to create an incident than is the chance that a more direct disastrous event, such as a casing failure or combined casing/cement failure, would create an incident.

While it is prudent to maintain the SSSV systems because of the prevalent need to provide a fail-safe shut down of the well conduit to the reservoir and protect workers, the public, and adjacent infrastructure, Company S looks for ways to minimize the interventions that invite incidents.

Regulatory requirements to install subsurface safety valves and full tubing strings on all Company S wells would require ~$150-$190 million for existing wells and addition of ~75 new wells at ~$120-$140 million in order to retain the same storage service capabilities. Maintenance rates would increase, causing O&M expense to increase by $2-4 million per year ($40-120 million over 20-30 years) and the risk of loss of control due to well entry and service work would increase 10-12 fold, directly aligning with the increase in the number of safety valves and tubing/packer strings.

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APPENDIX 6.2. INDUSTRY LITERATURE REVIEW – OPERATING EXPERIENCE

A ***2005 Gas Research Institute study, Project No. 809833, RISK ASSESSMENT METHODOLGY FOR ACCIDENTAL NATURAL GAS AND HIGHLY VOLATILE LIQUID RELEASES FROM UNDERGROUND STORAGE, NEAR-WELL EQUIPMENT, performed by URS Corporation under Contract No. 8604,*** provided both a literature review and survey techniques to arrive at component reliability estimates and failure rates of storage wells from all component failures and combined reliability causes. A fault-tree analysis methodology was adapted and used to predict failure rates of 4.9E-05 to 7.7E-04 with and without a downhole safety valve (DHSV), respectively, and a sensitivity range using several well configurations and applying uncertainty ranges to variables to push the 'without safety valve' rate to 1.7E-04 to 7.7E-04. URS estimated the probability of the same types of releases catching fire to be lower, in the 2.1E-05 to 9.7.E-05 range.

From survey data, URS estimated well failures occurring due to downhole safety valve maintenance at 1.78E-05, which is somewhat less likely than failures due to cement (6.4E-05) but similar to failures due to casing failure (1.6 to 2.9E-05) vehicular strikes (1.78E-05) and falling objects (1.34E-05). All these individual rates are “very unlikely” in terms of likelihood of occurrence.

Safety valve failures to close on demand are in the range of 1.95E-05 to 4.38E-06 per demand and surface safety valves by analogy are interpreted as having a failure to close at a very low 7.01E-08 per demand.

It is worthwhile noting that “failure” resulting in gas release during a well drilling or re-entry for service is one to two orders of magnitude greater than most failures due to well equipment: 3.41E-04 to 8.91E-05 per entry.

URS noted in the report that process safety general principles understand that the number of catastrophic incidents is a small percentage of lesser incidents that could have had catastrophic results; API 754 and other process safety standard performance indicator tiering apply this understanding.

URS noted that record keeping and data analysis were key to studying reliability and failure in a quantitative fashion, and encouraged uniform tracking of industry data for reliability issues and failures at the component level, along with evaluation of maintenance activities and reliability engineering improvement efforts, in order to develop continual improvement.

Moines and Iversen (1990, OTC 6462, Reliability Management of Subsurface-Controlled Subsurface Safety Valves for the ROGI Project), demonstrated in a 1990 paper that SCSSV failure was the primary cause of workover operations initiated due to completion equipment failures in offshore operations – 450 per 10,000 well years. The authors noted that reliability methods can be used to increase reliability and in particular that working with the manufacturer to enhance reliability in the design phase was essential. The paper reviews seven configurations of downhole safety valves, from shallow set, tubing retrievable surface controlled systems to deep set, surface controlled systems; the shallow systems were complemented with dual safety valves. Reliability data indicate that the deep set systems fare poorest, with failure rates of 1-3E-04 and shallow systems at 0.6-0.8E-04; the various dual-valve combinations reduce failure by an order of magnitude, to 0.3-0.6E-05.

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Moines and Strand followed up in 2000 with SPE #63112, "Application of a Completion Equipment Reliability Database in Decision Making", where historical evolution in reliability of subsurface safety valves (SCSSV) is demonstrated from what was largely a North Sea data set. The paper advocates a screening matrix to characterize risk and push the bounds of risk acceptance given consequence analysis so as to not compromise safety overall. Increasing test frequency is advised when there is an actual failure or a heightened risk of a well barrier failure.

Moines and Strand look at the issue of SCSSV removal from subsea completions and suggest that this be addressed on the basis of local/regional requirements and likelihood and consequence impact factors. The authors note a significant improvement in SCSSV performance occurred in their data set from Mean Time to Failure (MTTF) of 14.2 years in 1983 to 36.7 years in 1999. A trend toward design standardization using single rod piston, flapper type tubing retrievable safety valves without equalizing feature is credited with the increased SCSSV reliability and reduction in well interventions. SCSSV reliability improvements can be made by applying a system reliability approach encompassing the valve and its mechanical components as well as the control line, control line protectors, tubing hanger/x-mas tree interface and the surface hydraulic control unit.

Durham and Paveley, SPE 56934 "Radical Solutions Required: Completions Without Packers and Downhole Safety Valves Can Be Safe", 1999, found blowout frequency during workover in the 6.8E-04 range for their data set, with SCSSV workover frequency .02-.03 per year. The authors assess likelihood and consequence, where consequence is on a safety-environment-cost basis, and show that that the elimination of packers and downhole safety valves from completions can be tolerated, providing an increase in cost efficiency through reduction in equipment and well interventions. The risk assessment method includes fault trees and failure mode, effect, and criticality analyses, combined with quantitative analysis of an uncontrolled hydrocarbon release.

A key to the methodology is the addition of loss of control risk due to equipment failure. The authors establish loss of control frequencies for component failure and for workovers from worldwide data, then they relate completion component reliability to the need for workover to get the combined risk. Like a fault tree, the release potential is the sum of component failure leading to loss of containment plus the chance of workover loss of control, where workover loss of control is component failure rate=well workover rate multiplied by the chance of a workover loss of control incident.

Secondary controls can be employed to reduce criticality of a loss of control failure into the tolerable range with or without a safety valve, and these include gas/flame detection monitoring equipment, annulus pressure monitoring, emergency plans in place for rapid response well kill or control, pressure test verification of containment barriers, pressure monitoring and control equipment, and, during workovers, regular BOP testing and maintenance of dual barriers.

A downhole safety valve reduces consequences of relatively few events and only during normal operations, so the authors advise that the consequence level be assessed quantitatively. The likelihood of a loss of containment event during normal operations is low but the service of the valves has a greater chance of loss of control.

Powell and Van Scyoc (2011), SPE #145428, "Well Site Screening: The Critical Few", note that risk screening should be applied to define the most critical wells and then resources expended at those sites to gain the most benefit. It is impractical and unnecessary to use the same integrity maintenance, monitoring, and verification strategy at every well, and, rather, operators should see more rigorous

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integrity management practices at high risk wells. Powell and Van Scyoc developed and applied a structured risk assessment approach, with a goal to reduce risk to as low as reasonably practicable for continued safe operation.

Powell and Van Scyoc assessment criteria included well type and status (a reflection of the well as-built and current condition), maximum well pressure, maximum/normal flow rate, and fluid production characteristics as inputs, along with consequence impact attributes ranked by H2S exposure, flammability limits, and extent of liquid pool spread for releases at the surface, all compared to distance to population and environmental receptors. The authors divided their well set into three tiers defined relative to the H2S radius of exposure, gas dispersion radius at 50 percent of the lower flammability limit, and a 24 hour liquid release spread radius; the tier divisions, they noted, generally reflected regulatory practices and were otherwise conservative. Thus, the authors used a consequence-basis to risk-tier their wells without respect to likelihood for a well failure. The risk-tiers support different levels of integrity activity requirements – testing, inspection, monitoring, and other activities, including for the highest risk wells.

Powell and Van Scyoc noted lessons learned from the application of the screening. First, the method had no approach to handle downhole, subsurface product releases. Such a model or method is necessary, along with guidance for inspection, testing, and monitoring programs. Second, the method does not permit input variables that might be related to more than one release scenario (casing, tubing, flowline scenario for a single specific well). Input variables could be established for various well types, for which separate impact evaluations could be done for multiple major release scenarios. Third, they identified a need to incorporate wellbore fluid levels, well type, and pressure for screening impact susceptibility of underground sources of drinking water.

APPENDIX 6.3. ADDITIONAL NOTES AND GUIDANCE ON THE RISK MANAGEMENT PROCESS

Determining objectives and internal/external context

Each gas storage operator sets risk management objectives in the context of their own company's internal operating environment and capability. The operating environment includes the company's operating history and institutional knowledge, organizational structure for command-and-control of resources and influence by internal stakeholders. A company's capability is influenced by the knowledge, skills, and experiences of individual contributors, corporate structures, and the embodiment of controls within procedures, training, supervisory control and reinforcement and continual improvement activities.

The gas storage operator sets the risk management objectives in the context of the external operating environment, which includes, at a minimum, the concerns of public stakeholders and regulatory agencies, regulatory trends, natural gas infrastructure development and enabling trends, gas storage business trends, industry concerns as embodied in/through industry associations, industry recommended practices and guidelines, professional literature, academic research, and a wider body of knowledge, skills and experiences than any one company could have.

The risk analysis method – various forms of qualitative, semi-quantitative, or quantitative - depends on the company's capability, in and through its individual contributors' capability, to apply the risk analysis method in a consistent manner and achieve meaningful results. If past data aggregation and analysis has not been quantitative, it might be difficult initially to apply fully quantitative methods.

A similar risk analysis methodology could be desirable across the industry; however, one approach might be to start at a basic, semi-quantitative level, advising collection of reliability and safety data, so that continual improvement can be achieved along a path to more fully quantitative risk analysis methods. Industry literature reviewed indicates that there is potential to begin at a semi-quantitative level since some general failure rates are known and safety valve reliability experiences are known by some operators.

Analysis of risk: well-specific applications

Similar to impact factors and assessments used by Powell and Van Scyoc, storage operators could assess gas dispersion radius at 50 percent of the lower flammability limit, and a 24-hour liquid release spread radius. Alternatively, operators could apply CSA Z341.1 impact assessment following Gas Research Institute project GRI-00/0189 radius-pressure-casing size relationship, which uses worst case well flow capacity, ignition of the gas, and a heat flux of 5.0 kW/m2, representing a 30-second burn threshold.

Population density for widespread impact assessment could be tiered as follows:
0-1 per square mile
1-10 per square mile
10-100 per square mile
100-1000 per square mile
1000-10,000 per square mile
>10,000 per square mile

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Operators can assess impact potential due to fluid composition and maximum flow potential in two ways: at the maximum daily rate, and at an extended duration. The operator can assess each well's maximum flow capability, constrained by casing inner diameter, at absolute wellhead flow potential at maximum pressure. The extended flow capability (extended release volume) of the well can be calculated over various intervals. The operator could assume a maximum case of decline in reservoir pressure solely due to a leak at the well, or assume a minimum case where in a period extended beyond a few days, field withdrawal could be orchestrated to bring reservoir pressure down more rapidly. The operator can assess the potential of the well to release product other than dry natural gas; wells that could produce water, liquid hydrocarbon, solids, or noxious or hazardous gas constituents could be rated as potentially more severely impactful. The volume of greenhouse gas emissions and the local/global impact can be addressed in the assessment.

Evaluation of Risk

The operator can develop a decision tree specific to the question of whether a safety valve system is needed at each well. For wells that already have a safety valve, the decision tree could help the operator to demonstrate that the safety valve system is needed and located in the best place, or that the safety valve system is needed but not located in the best place, or that the safety valve system is not needed.

When the risk evaluation indicates that a specific well's loss-of-containment potential and impact potential are severe enough to warrant evaluation of the risk reduction with a safety valve, the operator can evaluate alternative means of reducing risk. With each alternative, the operator can assess both the risk reduction potential of the alternative as well as the risk increase potential related to the alternative.

Worldwide, safety risk thresholds are values-based and often stated for individual risk in terms of fatalities per capita per year, and a near-universal threshold of unacceptable risk in a tolerable risk framework is one in 10,000 fatalities per capita per year, whereas a widely acceptable risk threshold on the lower end of a tolerable risk framework is at one in 1,000,000 fatalities per capita per year.

Environmental risk thresholds are not well-established. However, most guidance on risk acceptability scaling is a mix of values-based/bounded constraint/utility basis relating to the number and type of receptors impacted (which often relates directly to radius of impact and what is in the radius of impact), the environmental impact duration, and the environmental recovery time.

Service reliability risk thresholds are not well-established since the evaluation criteria are usually utility-based (cost/benefit); the risk acceptability scaling is site specific and relates to the local impacts, duration, and service alternatives.

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SED Supplemental Data Response to SoCalGas Data Request 3
Supplemental information is shown in red as of 1/6/2020.
Supplemental information is shown in blue as of 1/15/2020.
Supplemental Information is shown in green as of 1/23/2020 As a general note, includes the following objection with all information provided in green. SED was relying on SoCalGas's response to SED Data Request 52 in order to supplement its answers to this response. However, SoCalGas's responses to SED Data Request 52 were non-responsive and/or incomplete, in the fashion described in the specific answers. Therefore, SED is unable to provide the supplemental information it indicated it would on January 15, 2020 at this time. SED encourages SoCalGas to re-consider its response to SED Data Request 52, and provide specific, directly responsive, and complete answers. Data dumps or references saying that SoCalGas has already provided SED information are not responsive to the questions. Rather, specific responses showing exactly which documents are responsive are required to answer the question.
At this time, SED stands by all objections it indicated it would re-consider at the last meet and confer.

General disclaimer: SED reserves the right to update Its data response, and has identified where SED requires more time in each answer. SED reserves the right to add to its answer to all question subparts requesting SED to identify the laws, rules, regulations and/or industry standards. Where SED has quoted from its testimony to answer a question, SED has omitted the footnotes from SED's testimony in the answer. However, these footnotes are all incorporated into each answer by reference.

1. YOU assert that SoCalGas failed to investigate the "blowout" from well Frew-3 (Violation 1 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the "blowout" from well Frew-3 on December 31, 1984.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating this blowout. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the blowout that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 1a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- One violation for failure to investigate the blowout from well Frew-3 spanning

from December 31, 1984, the last possible date of the blowout, to October 23, 2015, the date of the incident.

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the blowout from well Frew-3.

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

d. Identify the basis on which YOU contend that this alleged failure is a violation of California Public Utilities Code Section 451 ("Section 451").

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 1b.

2. YOU assert that SoCalGas failed to investigate the "blowout" from well FF-34A (Violation 2 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the "blowout" from well FF-34A on December 31, 1990.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating this blowout. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the blowout that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 2a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- One violation for failure to investigate the blowout from well FF-34A, spanning from December 31, 1990, the last possible date of the blowout, to October 23, 2015, the date of the incident.

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the blowout from well FF-34A.

SED relies on the Blade Report for this violation. SED reserves the right to update this answer at a later time.

d. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 2b.

3. YOU assert that SoCalGas failed to investigate the three parted casings discovered on December 31, 1994 (Violation 4 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the three parted casings discovered on December 31, 1994.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the parted casings. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 3a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- Four violations: One for failure to investigate each of the parted casings discovered between 1969 and 1994. As one of the parted casings must have been discovered in 1969 to set the beginning of the range, that first violation spans from December 31, 1969 the last possible date of its parting, to October 23, 2015, the date of the incident. Assuming that the remaining three parted casings were discovered December 31, 1994, those three separate violations each span from, at the latest, December 31, 1994 to October 23, 2015.

c. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas investigated the three parted casings discovered on December 31, 1994.

SED objects to this question as unduly burdensome on the grounds that it asks a question that SoCalGas does or should have the answer to. SoCalGas is or should be aware of audits that SED has conducted on SoCalGas. SED notes as part of its objection that SoCalGas should avoid asking questions to which SoCalGas does or should already have the answer in that they waste the limited time and staff resources of SED in this investigation. Failure to heed this instruction may result in SED identifying additional examples in which SoCalGas is not cooperating with SED's investigation.

d. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the three parted casings discovered on December 31, 1994.

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

e. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 3b.

4. YOU assert that SoCalGas failed to investigate the first parted casing in 1969 (Violation 3 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the first parted casing in 1969.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating this parted casing. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

SED requires a complete answer to Data Request 52, Question 2 as a condition precedent to completing the answer to this question. For reference, that question asks:

Related to AC_CPUC_SED_DR_27_0000351 July 20, 1962, Tidewater prepared an evaluation of the SS reservoir for future Sesnon Gas Storage distributed for review before August PUC hearings. Please provide all correspondence, reports, studies and testimonies, and the final contract for acquisition of the Sesnon Gas Storage field that occurred between 1962 and 1973 between Tidewater (and its associates),

Pacific Lighting, and the PUC regarding assessment and acquisition of the Sesnon Gas Storage (Aliso Canyon).

In DR 52, Question 2, SED asked, Related to AC_CPUC_SED_DR_27_0000351 July 20, 1962, Tidewater prepared an evaluation of the SS reservoir for future Sesnon Gas Storage distributed for review before August PUC hearings. Please provide all correspondence, reports, studies and testimonies, and the final contract for acquisition of the Sesnon Gas Storage field that occurred between 1962 and 1973 between Tidewater (and its associates), Pacific Lighting, and the PUC regarding assessment and acquisition of the Sesnon Gas Storage (Aliso Canyon).

SoCalGas answered, SoCalGas objects to this request on the grounds that it is vague and ambiguous, and overly broad and unduly burdensome. SoCalGas further objects to this request to the extent it seeks information that is outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Please refer to SoCalGas' previously provided response to SED Data Request 17 ("DR- 17") dated March 30, 2018.

SED views this as a non-responsive answer to SED's good faith effort to ask SoCalGas a specific question, as the response to DR 17 is a data dump. Due to SoCalGas being non-responsive to SED's good faith efforts dispense of its duties to investigate SoCalGas from a safety perspective, SED will not add anything to this response at this time.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 4a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- Four violations: One for failure to investigate each of the parted casings discovered between 1969 and 1994. As one of the parted casings must have been discovered in 1969 to set the beginning of the range, that first violation spans from December 31, 1969 the last possible date of its parting, to October 23, 2015, the date of the incident.

c. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas investigated the first parted casing in 1969.

SED objects to this question on the grounds that It Is unduly burdensome. As the entity that was audited, SoCalGas has or should have the answer to this question. SED reminds SoCalGas, pursuant to the meet and confer in November, that questions such as this one, where SoCalGas already has the answer, wastes limited SED staff time and resources, and should not be asked. The instant question should be withdrawn.

d. Identify the basis for SED's assumption that the first parted casing was discovered, at the latest, on December 31, 1969.

As noted on pages 8 and 9 of SED's opening testimony,

SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451, as follows:

> Between 1969 and 1994, four wells were discovered to have parted casings. However, Blade found no evidence that SCG prepared root cause analyses, collected samples, performed lab analyses, or taken photos of failures, or developed failure analysis reports to document these failures. The only documents found were well operations daily reports where on-site rig activities were reported.

Each of these sentences reference to, and are based upon page 165 of the Blade Report. As that part of the report notes that four wells were discovered to have parted casings between 1969 and 1994, SED assumes that at one well had a parted casing that was discovered the last possible date of 1969, because that would be the basis for the start date of 1969. SED conservatively assumes the last day of 1969 as the start date of that violation, the last possible day that first well discovery could have happened.

SED reserves the right to update the date of this violation from conservative assumptions to more concrete dates if SED discovers additional information.

e. Identify the date on which YOU understand SoCalGas took control as operator ofthe ALISO CANYON.

SED objects to this question on the grounds that it is unduly burdensome in that SoCalGas Is asking a question to which SoCalGas demonstrably does or should already have the answer. SED reminds SoCalGas to avoid wasting SED limited staff time and resources asking such questions.

f. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the first parted casing.

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

g. Admit that SoCalGas could not have violated any requirement or order of the Commission with respect to the maintenance and operation of Aliso Canyon prior to assuming control as operator of ALISO CANYON.

SED concedes this point, provided that SoCalGas had no role in ownership, maintenance, operation, or any control whatsoever. SED reserves the right to amend its testimony accordingly.

h. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 4b.

5. YOU assert that SoCalGas failed to investigate the remaining 54 leaks (Violations 7-60 alleged in OPENING TESTIMONY).

a. Please describe the "investigation" SED believes would have constituted a reasonable

response to each of the “remaining 54 leaks.”

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the leaks. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right provide an additional substantive answer.

Generally, the 2014 investigation of FREW 2 demonstrates the type of investigation that would be reasonable to determine the extent and cause of earlier leaks detected by SoCalGas. While 2014 tools may be more refined, the basic tools have been available for decades.

SED requires an answer to Data Request 52 Question 9 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In Data Request 52, Question 9, SED asked,

In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In response, to this question, SoCalGas stated,

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "SIMP Model Studies" and term "similar," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the SIMP Pilot Project. Please refer to SoCalGas' response to SED Data Request 25 ("DR-25") dated August 14, 2018. Rather than providing an answer to a direct specific question, this is a data dump, referring to over 1500 documents. It was during SED's review of SoCalGas' response to DR 25 that the SIMP Model Study report of corrosion on well FREW 2 was found. In an ongoing effort to give SoCalGas credit for all investigations into well corrosion and anomalies, SED asked for similar reports. Due to the non-responsive answer of SoCalGas, SED must assume that SoCalGas performed no other studies of wells prior to 2015 that would have identified corrosion or anomalies in well

tubings or casings. Therefore, SED has no further comments on this issue at this time.

Despite, SED's objection to question 5a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. As noted on pages 8 and 9 of SED's opening testimony,

SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451, as follows:

a. To avoid double counting violations, SED assumes that the 60 leaks identified before the Aliso Canyon incident included the six blowouts and parted casings identified above. As such, the remaining 54 leaks that went without investigation should constitute a separate set of up to 54 violations. At the latest, these violations began on October 22, 2015, the last possible date before the incident on October 23, 2015.

c. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas investigated the remaining 54 leaks.

SED objects to this question on the grounds that It Is unduly burdensome. As the entity that was audited, SoCalGas has or should have the answer to this question. SED reminds SoCalGas, pursuant to the meet and confer in November, that questions such as this one, where SoCalGas already has the answer, wastes limited SED staff time and resources, and should not be asked. The instant question should be withdrawn.

d. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the "remaining 54 leaks."

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

Blade reviewed the well files and did not find any records that suggested an investigation to determine the cause of leaks was performed for the 54 leaks. Based on recent review of well file FREW 2 compared to the SIMP Study for well file 2, it appears that SoCalGas may only add logs to the Well File, not reports or findings. Therefore, SED requires an answer to Data Request 52 Question 9 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations, analyses, test results, and results. Each report should be provided in separate, searchable pdf document(s).

Please refer to additional response in green to Question 5a above.

e. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 5b.

6. YOU assert that SoCalGas "did not properly follow its own 1988 plan todetermine the condition of the casing in 12 wells" and SS-25. (OPENING TESTIMONY, page 10).

a. Please identify the law(s), regulations, or rules that required SoCalGas to test the production casing of its wells for metal loss on or about 1988.

SED objects to this question as mischaracterizing SED's testimony. SED's testimony asserts on page 10 that, "SoCalGas's failure to follow Its own 1988 plan to check the casing in 12 wells for metal loss violates Section 451." This violation does not discuss testing.

b. Please state the industry standard(s) for testing the production casing of oil and gas

storage wells that were in effect on or about 1988.

SED objects to this question as mischaracterizing SED's testimony. SED's testimony asserts on page 10 that, "SoCalGas's failure to follow Its own 1988 plan to check the casing In 12 wells for metal loss violates Section 451." This violation does not discuss testing.

c. Please identify all tools available, on or about 1988, which were designed to evaluate the metal loss in the production casing of oil and gas wells.

SED objects to this question as unduly burdensome. SoCalGas has access to the same information as SED, and can research the tools available at this time period as well as SED can, and this places an undue burden on SED to identify each tool available at the time. Notwithstanding this objection, SED identifies the following tools.

Tools available on or about 1988 that were designed to evaluate the metal loss in the production casing of oil and gas wells include the following:

Corrosion Logs were used to detect pitting and wall loss in casings as early as 1971. (*See* Donald L. Katz, AIME, U. of Michigan, "Monitoring Gas Storage Reservoirs," June 10, 1971, SPE PAPER No. 3287. *See also,* J.A. Bazzari, Getty Oil Co./Kuwait Oil Co., "Well Casing Leaks History and Corrosion Monitoring Study, Wafra Field," 1981, SPE PAPER No. 17930 (see log showing detection of wall thickness, Figure 4, page 53.)

Other tools designed to evaluate metal loss are included in the following passage:

"Corroded casing sometimes can be located by a high-resolution caliper log; spontaneous-potential logs have been used to locate depth intervals where active corrosion is taking place (Kendall, 1965). Commercial logging services are available for detecting corroded casing. An electromagnetic casing inspection log measures changes in the mass of metal between two coils; loss of mass may be due to corrosion (Edwards and Stroud, 1964). A pipe-analysis survey is run with a centralized probe that employs several coils (Bradshaw, 1976). This survey is reported to provide information on the thickness of casing penetrated by corrosion, whether the damage is internal or external, and isolated or circumferential. The electromagnetic-thickness survey measures the average casing thickness over an interval of about 0.6 m and can be used to monitor changes in thickness with time. Casing-inspection logging methods are summarized by Nielsen and Aller (1984)." EPA Web Archive: https://archive.epa.gov/esd/archive-geophysics/web/html/well_completion_logging.html

SED might provide additional future references.

SED adds the following reference, which is also included as an attachment.

1988.0101.SPWLA-1988-UU-NN

d. For each of the tools that YOU identify in response to Request 6(c), please describe YOUR understanding of the tool's efficacy in accurately identifying wall loss.

SED incorporates it's answer to question 6c by reference.

e. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 6a.

7. YOU assert that SoCalGas did not "employ reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25" prior to the drilling of two groundwater wells which were drilled for RCA purposes (OPENING TESTIMONY, page 39).

a. Please explain what YOU believe a "reasonable understanding of groundwater depths relative to the surface casing shoe and production casing of well SS-25" would have been.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the groundwater depths in the question. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of understanding might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and may endeavor to provide an additional substantive answer.

SED requires an answer to Data Request 52 Question 7 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
>
> a. Well Number
> b. Installation record showing at least date drilled, depth of well, depth of water from surface.
> c. All data collected and recorded from these wells.
> d. One map showing location of shallow water wells at Aliso.

SED Data Request 52, Question 7 asked.

Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
a. Well Number
b. Installation record showing at least date drilled, depth of well, depth of water from surface.

c. All data collected and recorded from these wells.
d. One map showing location of shallow water wells at Aliso.

SoCalGas responded to this question:

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "shallow water observation wells," overly broad and unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Prior to October 23, 2015, gas storage observation wells SS-5 and W3A were used to monitor pressure in the west and east field areas, respectively. Due to the incompleteness of this answer in failing to address subparts b, c, and d of Data Request 52, Question 7, SED is unable to answer this question at this time. Without knowing additional data that might have been available to SoCalGas, SED relies on the Blade Report for response to this question.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to employ the understanding you explain in response to Request 7(a).

Despite, SED's objection to question 7a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. The rules include California Public Utilities Code Section 451, as identified in subsection a, which concludes on page 44 of SED opening testimony,

> By allowing groundwater to cause corrosion on the 7 inch and 11 ¾ inch casings on SS-25, SoCalGas violated Section 451. This violation begins on August 30, 1988, the date SoCalGas produced its Interoffice memo calling for inspections of the SS-25 casing, and continues to October 23, 2015, the beginning date of the incident.

The rules also include California Public Utilities Code Section 451, as identified in subsection b, which concludes on page 45 of SED opening testimony,

> SoCalGas's failure to assess the relationship between groundwater in and around the SS-25 wellsite, and the surface casing corrosion of that well on SS-25 constitute a violation of Section 451. This violation begins on August 30, 1988, the date SoCalGas produced its Interoffice Memo calling for inspections of the SS-25 casing, and continues to October 23, 2015, the beginning date of the incident.

To maintain its obligation to provide a safe system to protect employees and the public, SED expects SoCalGas will develop safe operation and maintenance standards and will implement them in the course of its normal business. These in-house procedures serve as a type of operating requirement for SoCalGas. As an example of SoCalGas not implementing its own standard, refer to SoCalGas' Company Operations Gas Standard for Pipeline Integrity - Design and Application of Cathodic Protection, SCG 186.002. This Standard was modified in 2000 to add cathodic protection for gas Storage, specifically well casings. Gas Storage management is charged with the responsibility of implementing the standard. Yet, 15 years later, well SS-25 failed from casing corrosion.

The NACE International standard practice provided in response to question 7c identifies procedures to determine the need for cathodic protection (CP) and the current requirements to achieve CP of well casings associated with oil and gas production and gas storage. It also outlines practices for the design and installation of CP systems and for their operation and maintenance. The purpose of this standard is to ensure more effective prevention of corrosion of well casings by making available reliable information about CP as it relates to well casings. This standard is intended for use by corrosion engineers in oil and gas production, especially those concerned with the CP of steel well casings. NEW REFERENCE: 2007.0101.NACE-SP0186-NN (Standard – first issued in 1986)

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support

SED's contention that SoCalGas did not employ a "reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25" prior to the drilling of the two groundwater wells which were drilled for RCA purposes.

SED adds the following reference, which is provided as an attachments: SPE-3287-MS and SPE-17930-MS

d. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to questions 7b and 7c. Also, see an additional new reference: 1978.0701.PETSOC-78-03-04_NN, SPE-17930-MS

8. YOU assert that SoCalGas did not "assess the relationship between groundwater in and around the SS-25 well site, and the surface casing corrosion of that well" (OPENING TESTIMONY, page 44).

SED objects to this question because it was already encompassed by all of question 7, and answered there. Therefore, SED incorporates by reference it's answers to question 7 in response to the questions for question 8.

a. Please identify the specific actions that YOU believe SoCalGas should have taken, prior to the SS-25 leak, to "assess" the relationship between the groundwater and the surface casing.

SED requires an answer to Data Request 52 Question 7 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
> a. Well Number
> b. Installation record showing at least date drilled, depth of well, depth of water from surface.
> c. All data collected and recorded from these wells.
> d. One map showing location of shallow water wells at Aliso.

See Response to Question 7a above.

b. Identify the laws, rules, regulations, or industry standards that required SoCalGas to assess the relationship between groundwater around the SS-25 well site, and the surface casing corrosion around that well.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 7b, 7c, and 7d.

c. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to employ the specific actions you describe in response to Request 8(a).

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 8b.7(b).

d. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas did not "assess the relationship between groundwater in and around the SS-25 well site, and the surface casing corrosion of that well."

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

See the answer to question 7b and c.

e. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 8b.

9. YOU assert that SoCalGas had no systemic practices to protect surface casing strings against external corrosion and therefore did not employ "a proper understanding of the consequences of corroded surface casings and uncemented production casings" (OPENING TESTIMONY, page 45).

a. Please describe what YOU believe a "proper understanding of the consequences of corroded surface casings and uncemented production casings" would entail.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the information identified in the question. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the information identified in the question that is or was in the control of SoCalGas, and analyze it to determine what type of understanding might have been adequate.

Notwithstanding this objection, SED notes the follows: As discussed in certain scholarly articles, "Casing integrity and cement evaluation are not new concepts, in fact operators have evaluated reservoir and well integrity since the inception of underground storage a century ago." Pg.1, Sebastian Kamgang, et al & Baker Hughes Incorporated, "Innovative Cement and Casing

Corrosion Evaluation Technologies Provide Reliable Well Integrity Information In Natural Gas Storage Wells" 2017, SPWLA 58th Annual Logging Symposium, June 17-21, 2017

As an operator of multiple gas storage areas since as early as 1943, SoCalGas should by now have a thorough understanding of the consequences of corroded surface casings and uncemented production casings. A basic understanding would be that an uncemented casing that is exposed to soil and groundwater without any protection, such as cathodic protection, will corrode and eventually leak. A proper understanding of this concept would easily lead an engineer to the conclusion that some sort of protection is necessary to avoid the maintenance costs associated with repairs or replacement of a well. For additional information, SED adds the following references: SPE-2910-MS, SPE-3287-MS and SPE-17930-MS, NACE-SP0186-NN, 1959.0519.API-59-199_NNN, 1974.0701.SPE-4682-PA_NNN, 2007.0627.SPE-108906-MS_NNN, 2007.0924.SPE-108195-MS_NNN, 2007.1111.SPE-108698-MS_NNN

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to employ the understanding you explain in response to Request 9(a).

Despite, SED's objection to question 9a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. The rules include California Public Utilities Code Section 451, as identified on page 47 of SED's testimony, which states,

> SoCalGas violated Section 451 because it did not have systematic practice to protect surface casing strings against external corrosion, and because it did not understand the consequences of corroded surface casings and uncemented production casings. This violation begins on August 30, 1988, the date SoCalGas produced its Interoffice Memo calling for inspections of the SS-25 casing, and continues to October 23, 2015, the beginning date of the incident.

Good completion practices include the use of drilling mud with an alkaline Ph; the circulation of cement for the entire length of the casing; use of similar metals in all parts of the structure; and the insulation of the well line from the casing. See page 2, 1970.0101.SPE-2910-MS (attached). See also 7.b

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to employ "a proper understanding of the consequences of surface casing and uncemented production casings."

See response to 9a.

d. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to questions 9a and 9b.

10. YOU assert that SoCalGas did not understand "the extent and consequences of the corrosion in other ALISO CANYON Storage wells" because of its alleged failure to investigate previous failures (OPENING TESTIMONY, page 7).

SED objects to this question because it was asked and answered. This question encompasses those that were asked already as part of this data request. See in particular, questions 1 through 6 and question 10 of this data request. This objection applies throughout the data response, and includes references to other data responses to show certain applicable data responses.

a. Please describe what YOU believe SoCalGas should have done to understand the "extent and consequences of the corrosion in other ALISO CANYON storage wells."

See responses to 6c and 9a

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to engage in the actions YOU explain in response to Request 10(a).

SED objects to this question because it was asked and answered.

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to understand "the extent and consequences of the corrosion in other ALISO CANYON storage wells."

See response to 6c and 2012.1111.SPE-161983-MS_NNN

d. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to questions 9a and 9b.

11. YOU assert that SoCalGas "did not attempt to understand causes of the leaks at 60 wells" at ALISO CANYON (OPENING TESTIMONY, page 11).

a. Do YOU contend that SoCalGas conducted no investigation at all for the leaks mentioned above?

SoCalGas has represented to the Commission that, "The casing leaks, as SoCalGas understands them to be identified in the Blade Report, were successfully assessed and addressed by SoCalGas and, where appropriate, further investigation was performed. In order to remediate any leaks, SoCalGas necessarily had to analyze and diagnose the issue, and then implement a fix, as needed." SED reserves the right to re-visit this issue once Blade has had an opportunity to address SoCalGas's statement, and pending SoCalGas providing underlying facts to show the veracity of this statement.

Upon further review, SoCalGas did a model SIMP study to determine the condition of the casing on Frew 2 in 2014. SED reserves the right to provide further updates to this answer in the future.

b. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's response to Request 11(a).

See response to question 11a.

c. What do YOU contend constitutes a "leak"?

A leak is any failure of the well integrity that results in a release of gas to the surrounding reservoir soil, groundwater and/or to the atmosphere. Leaks include those leaks of 60 wells at Aliso Canyon, as identified by the Blade Report at page 4, as mentioned in footnote 42 of SED's opening testimony. See also page 9 of SED's testimony, which says,

> To avoid double counting violations, SED assumes that the 60 leaks identified before the Aliso Canyon incident included the six blowouts and parted casings identified above. As such, the remaining 54 leaks that went without investigation should constitute a separate set of up to 54 violations. At the latest, these violations began on October 22, 2015, the last possible date before the incident on October 23, 2015.

d. Please describe what actions YOU believe are necessary for a reasonable investigation of a leak.

SED objects to this question in that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating leaks on SoCalGas's system. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED reserves the right to investigate and audit SoCalGas for safety related purposes.

SED also objects to this question as vague and overly broad. This question would have SED provide an up front commitment to what constitutes a necessary investigation of a leak for every instance without having the facts associated with a given leak, thereby potentially compromising the ability of SED's investigators to do their work when investigating leaks for safety related purposes.

Notwithstanding these objections, please refer to the responses to 6c, 9a and 10c

Please also see Blade's Response to SED Data Request 49, Questions 3 through 5. For context, these responses are replicated here.

2.3 Question 3

Does Blade agree with the statement that, "The Blade Report fails to recognize, however, that a 'formal investigation' of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well, nor necessary. While Blade was able to cut, extract, and thoroughly examine the casing at well SS-25 because there were plans to abandon the well, it is not feasible for SoCalGas to perform the same level of failure analysis on active gas storage wells."

2.3.1 Response 3

Blade disagrees with the statement.

2.4 Question 4

If Blade agrees with the statement in question 3, please explain why.

2.4.1 Response 4

See Response 5.

2.5 Question 5

If Blade disagrees with any portion or all of the statement in question 3, please explain why it disagrees.

2.5.1 Response 5

Solution 6: Conduct a Casing Failure Analysis from the Blade Main Report, Section 5.3.1, Page 232, is replicated here for reference.

Solution 6: Conduct a Casing Failure Analysis

Despite numerous casing failures, no data were provided to indicate that failure causes were investigated. Casing failures need to be formally investigated so that their causes are identified and their implications are understood. Understanding and interpreting failures are critical to defining the propensity or risk of such failures field wide. Such analysis is an important part of any risk assessment. The cause may be straightforward, well specific, and easily mitigated. However, if the cause appears to systemic, or the potential consequences are serious, then a more comprehensive investigation is needed to evaluate the potential risks to other wells in the field so that the appropriate mitigation steps are taken. For example, failure investigation of casing OD corrosion in another well might have directed attention to SS-25 and other similar wells. Running an inner string or plugging a well are valid mitigations, but prior to such actions, the cause of the casing leak or failure should be understood. **The type of investigation should be commensurate with the risk and consequence of the failure, and should be part of the well integrity management system.**

As stated in Solution 6, the last sentence; "The type of investigation should be commensurate with the

risk and consequence of the failure, and should be part of the well integrity management system." It is understood that all failures cannot be treated like SS-25, nor should they. The level of investigation depends on many things including the depth of the failure. It may not be feasible, practical, or necessary, to recover production casing from a deep leak. However, inspection and diagnostic tools are available to determine the nature of the failure, such as, a hole, corrosion—internal or external over a large or small area, location of a failure—pipe body or connection, etc. Such data should be integrated and analyzed to assess the possible causes and develop some hypothesis that can be used to evaluate other wells with failures. Once the failure has been evaluated and understood, the appropriate steps can be taken to determine the disposition of the well. The well can be repaired (inner strings, etc.) or plugged and abandoned if not repairable or if the well is no longer needed. SoCalGas did repair wells or plugged and abandoned wells after the failures were identified.

e. Identify the laws, rules, regulations, and/or industry standards, if any, that YOU believe require SoCalGas to engage in the actions YOU describe in response to Request 11(d).

Despite, SED's objection to question 11d, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly.

SED's testimony on pages 8 and 9 state in part,

SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451, as follows. . .

> To avoid double counting violations, SED assumes that the 60 leaks identified before the Aliso Canyon incident included the six blowouts and parted casings identified above. As such, the remaining 54 leaks that went without investigation should constitute a separate set of up to 54 violations. At the latest, these violations began on October 22, 2015, the last possible date before the incident on October 23, 2015.

In addition, See API RP 585, as identified in Blade's data response to SED Data Request 49, Question 6, which is replicated below for context.

2.6 Question 6
With regards to the statement, that, "a 'formal investigation' of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well. . .", what levels of
examination are feasible for an active well that SoCalGas could have performed in Blade's opinion?

2.6.1 Response 6
This is addressed by Solution 7: Regulations Should Require a Level 1 (Per API RP 585) Analysis of All Failures in the Blade Main Report, Section 5.3.1, Page 232, replicated here for reference.

Solution 7: Regulations Should Require a Level 1 (Per API RP 585) Analysis of All Failures API RP 585 Pressure Equipment Integrity Incident Investigation, discusses failure investigation of pressure equipment [2]. The Aliso Canyon wells are a form of complex pressure vessels. A Level 1 type analysis of failures, as a minimum requirement, will identify the immediate causes of the failures or near misses and allow operators to understand the implications, if any.

Figure 8 shows the different levels of investigation as discussed in RP 585. A Level 1 investigation may be appropriate for most casing failures and can be done quickly with no disruption to field operations. API RP 585 was developed for Pressure Equipment Integrity Incident Investigation; however, Blade presents this as an option that could be applied to Gas Storage Well Integrity Management.

	Level 1 Investigations	Level 2 Investigations	Level 3 Investigations
Incident Characteristics	— Unexpected condition or damage found that if it had been allowed to progress would have led to loss of containment before the next scheduled outage or inspection interval. — Discovered PEI damage significantly beyond expectation but with no loss of containment or unit shutdown. — Small leaks (other than environmental fugitive emissions) from pressure equipment or joints that were easily contained. — Typically no fire, significant toxic release, injuries, or environmental damage would occur in a Level 1 incident.	— Leak from pressure equipment that resulted in or could have resulted in localized equipment damage, small to medium size release quantity, or small safety or environmental damage. — Unexpected pressure equipment failure from damage mechanisms or structural deterioration. — Unexpected pressure equipment damage or associated structural damage discovered that required equipment or unit shut down or immediate mitigation. — Repetitive Level 1 type characteristics in the same process or system.	Leak or rupture from pressure equipment that resulted in or could have resulted in significant process safety incident or environmental damage, equipment damage, large release quantity, or production loss.
Investigation Characteristics	Investigate using less structured analysis tools such as "What If" or "5-Whys." Uses evidence, judgment, and experience to identify causes.	Investigate using company or department causal factor identification or logic trees, seeking probable contributing and root causes.	Investigate using company structured root cause analysis (RCA) seeking to determine the deepest management system and cultural causes.
Team Makeup Recommended	Investigated by the PEI personnel from the affected area and trained in simple investigation techniques. Can be investigated by one person, possibly two. Involve subject-matter experts (SMEs) as needed.	Leader would be someone from the affected area trained in investigation techniques. Team members would include one to three others of different disciplines from the area; include at least one PEI person on the team. Involve SMEs as needed.	Leader would be someone trained in structured RCA and from another area of the plant or another business unit. There would be at least three team members and possibly from different disciplines or groups, such as inspection, operations, process engineering, maintenance, or process safety. Appropriate SMEs should be included on the team.
Initiation	Within a few days.	Begin investigation as soon as practical (e.g. 1 to 2 days).	Begin freezing and collecting evidence as soon as practical (e.g. within a few hours).
Sponsorship	Supervisor of investigator (First Line Supervisor).	Department Head level (Second Line Supervisor).	Management with overall responsibility for Safety Health Environment for the site.

Figure 8: API 585 Inspection Levels

Failed casing in an active well can be analyzed using casing wall thickness inspection, downhole camera, and other diagnostic tools as discussed in Section 2.2.1 Response 2. This may provide data that can be used to interpret causes for the casing failure.

f. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answers to the other parts of Question 11.

12. YOU assert that the Aliso Canyon storage wells had "numerous casing leaks" and assert

that these leaks “may have been relevant to the conditions at SS-25.” (OPENING TESTIMONY, page 7).

a. Describe how each of the alleged “numerous casing leaks” were “relevant to the conditions at SS-25.”

SED objects to the request to describe how each of the alleged numerous casing leaks were relevant to the conditions at SS-25 as unduly burdensome. SED further objects to this question as mischaracterizing SED's testimony. SED stated that the leaks "may have been relevant to the conditions at SS-25", not that they "were" relevant. SED answers this question with the understanding that SoCalGas meant to replace the term "were" with "may have been".

The numerous casing leaks at the Aliso Canyon storage wells may have been indicators that other wells at the storage facility, including well SS-25, were also likely to experience leaks, as well as threats related to leaks, including the documented corrosion that the casing of well SS-25 had. While the Aliso field is geologically complex, except for recently drilled wells, all of the wells were constructed in the same time period of similar materials and are exposed to similar environmental and gas quality conditions. Specifically, the inclusion of SS-25 with other wells on a 1988 list for evaluation and the 2014 finding in the SIMP study of FREW 2 that the casing had numerous leaks, should have been sufficient information to cause SoCalGas to look more closely at SS-25 for corrosion or other causes of leaks.

b. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED’s contention that the “numerous casing leaks” “may have been relevant to the conditions at SS-25.”

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

In the 2014 evaluation of FREW 2, there was clear evidence of external corrosion which should have raised an immediate concern for other wells exposed to similar conditions. Corrosion was extensive, including 82% loss with 0% remaining strength. See SoCalGas’s Data Response to SED Data Request 25.

SED requires an answer to Data Request 52 Question 9 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In Data Request 52, Question 9, SED asked,

In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In response, to this question, SoCalGas stated,

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "SIMP Model Studies" and term "similar," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the SIMP Pilot Project. Please refer to SoCalGas' response to SED Data Request 25 ("DR-25") dated August 14, 2018. Rather than providing an answer to a direct specific question, this is a data dump, referring to over 1500 documents. It was during SED's review of SoCalGas' response to DR 25 that the SIMP Model Study report of corrosion on well FREW 2 was found. In an ongoing effort to give SoCalGas credit for all investigations into well corrosion and anomalies, SED asked for similar reports. Due to the non-responsive answer of SoCalGas, SED must assume that SoCalGas performed no other studies of wells prior to 2015 that would have identified corrosion or anomalies in well tubings or casings. Therefore, SED has no further comments on this issue at this time.

13. Do YOU contend that SoCalGas has or had authority to compel Daniel Clayton of BOOTS AND COOTS to appear for an examination under oath in response to the SUBPOENAS? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question to the extent that it calls for legal conclusion with regards to SoCalGas's authority to compel Mr. Clayton to appear for examination under oath.

SED further objects to this question on the grounds that SoCalGas has asked SED to provide a legal justification for one of its asserted violations, which SoCalGas agreed it would not do in the pre-hearing conference.
SoCalGas's position was that SED should identify alleged violations with specificity in opening testimony. SED identified a concern that SoCalGas not cross-examine SED's witnesses as lawyers for concluding that there was a violation, and SoCalGas voiced no objection to this concern. SED has now proceeded in reliance on SoCalGas's assurance on the record that it would not cross-examine SED's witnesses for identifying the legal justifications for alleged violations in testimony, but this question does exactly that. For context and reference, SED quotes the pertinent portion of the transcript here.1
The next question concerns the deadline for SED to submit alleged violations and the factual and legal justifications for each alleged violation.· My question is

whether it would be reasonable to set a deadline of opening testimony for SED to submit alleged violations, and the factual justifications for each alleged violation, and set a deadline of opening briefs for SED to submit the legal justifications for its alleged violations?
Would any party like to respond to my question?· SoCalGas.
MR. STODDARD:· SoCalGas's position on this is that SED should identify the alleged violations with specificity in its opening testimony sooner, if possible; but in its opening testimony would be acceptable to SoCalGas as we had proposed in our prehearing conference statement.
MR. SHER:· Your Honor, SED would not necessarily be opposed to such if SoCalGas agreed now that it would not waste time cross-examining SED's witness as to their legal basis for tying violations to code sections, et cetera.
ALJ KENNEY:· Does SoCalGas have a response at this time?
MR. STODDARD:· SoCalGas is not going to waive any rights to cross-examination. Although, I would ask for clarification what exactly is meant by "legal basis" here?
MR. SHER:· The way your Honor set this out is that the violations would be set forth in the opening, and then the legal issues would be discussed in the briefing. To the degree -- it is highly unlikely that SED's witness will be a lawyer.· So we don't want SoCalGas, if we are going to do this all in our opening testimony, to cross-examine the witness as to their legal basis for concluding that this is a violation, for example, of 451.

MR. STODDARD:· SoCalGas does not object to that.
ALJ KENNEY:· Thank you.

[1] See I.19-06-016, Pre-hearing conference transcripts, pp. 43 : 11 to 44 : 28.

14. Do YOU contend that SoCalGas has or had authority to compel Mike Baggett of BOOTS AND COOTS to appear for an examination under oath in response to the SUBPOENAS? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question to the extent that it calls for legal conclusion with regards to SoCalGas's authority to compel Mr. Baggett to appear for examination under oath. SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

15. Do YOU contend that SoCalGas was legally obligated to include a term in its STANDARD SERVICES AGREEMENT with BOOTS AND COOTS that required BOOTS AND COOTS to subject itself to the same provisions to cooperate with SED's pre-formal investigation that SoCalGas was required to follow? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question to the extent that it calls for legal conclusion with regards to the legal obligations that SoCalGas had to include one or more terms in its STANDARD SERVICES AGREEMENT with BOOTS AND COOTS. SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

16. Do YOU contend that SoCalGas was legally obligated to include a term in its STANDARD SERVICES AGREEMENT with BOOTS AND COOTS that required BOOTS AND COOTS to respond to investigation-related inquiries from SED and/or Blade? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question in that it calls for a legal conclusion, asking for SED's views as to legal obligations of SoCalGas and requirements of Boots and Coots. SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

17. Do YOU contend that YOU have or had jurisdiction over the contractors that SoCalGas engaged to perform services in connection with responding to the ALISO CANYON leak? If not, do YOU contend that including the provision noted on page 58 of the OPENING TESTIMONY (i.e., a provision that required the contractor "to subject itself

to the same provisions to cooperate with SED's pre-formal investigation that SoCalGas itself was required to follow") would have conferred upon YOU such jurisdiction over SoCalGas' contractors?

SED objects to this question in that it calls for a legal conclusion with respect to whether SED has had or does have jurisdiction over SoCalGas's contractors.
SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

18. Identify all actions YOU believe SoCalGas should have taken to compel BOOTS AND COOTS personnel to comply with YOUR SUBPOENAS.

SED objects to this question in that it calls for a legal conclusion with respect to steps SoCalGas should have taken to compel Boots and Coots personnel to comply with SED's subpoenas.
SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

19. Identify and produce all DOCUMENTS evidencing service of YOUR SUBPOENAS on BOOTS AND COOTS.

SED served subpoenas on SoCalGas to produce Boots and Coots, but not on Boots and Coots directly.

20. Identify all actions YOU took to compel BOOTS AND COOTS personnel to comply with YOUR SUBPOENAS.

SED served SoCalGas with subpoenas to produce Boots and Coots, but did not subpoena Boots and Coots personnel directly.

21. Identify the basis on which SED contends that the lack of terms in the STANDARD SERVICES AGREEMENT as discussed in Requests 15 and 16 is a violation of Section 451.

SED objects to this question as ambiguous and vague in that it does not identify the page number or passage of SED's opening testimony to which it is referring. SED further objects to this question as vague and ambiguous in that it does not clarify what "Requests 15 and 16" means, and does not clarify the passages to which the question is referring. If SED receives clarification, SED reserves the right to object to this question to the extent It calls on SED to make a legal conclusion. SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

22. Produce all DOCUMENTS reflecting COMMUNICATIONS between YOU and BOOTS AND COOTS.

SED objects to this question as unduly burdensome on the grounds that it asks for extensive communications that could take extensive man hours to prove that there is not a single communication that SED has not turned over. Also because of undue burden on SED, SED does not understand this request to include those documents that SoCalGas forwarded from Boots and Coots to SED, or from SED to Boots and Coots. SED further objects to this request as vague and overly broad, asking for all communications between SED and Boots and Coots; not merely those that are within the scope of this proceeding.

Notwithstanding these objections, to the best of SED's knowledge at this time, SED has already produced to SoCalGas all documents reflecting communications between SED and Boots and Coots related to the instant proceeding. These include the Examination Under Oath transcripts of Mr. Danny Walzel and Mr. Mike Kopecky.

23. YOU assert on page 70 of YOUR OPENING TESTIMONY that "Data in the SS-25 file reveals an ongoing detection of leaks at the bottom of the well." Identify the specific data that YOU contend reveals an ongoing detection of leaks.

The specific data is provided In the Bates numbers shown in footnote 443 of SED's opening testimony; SS-25 Well File, Supporting Attachments SED 01774-01778, 01804-01810,[2] and 01894-01895.

24. YOU assert on page 72 of YOUR OPENING TESTIMONY that "The Well File for SS-25 is not kept in any particular order. Typically, such a file would be maintained in chronological order." State all facts, reasons, and grounds upon which YOU base YOUR assertion that gas storage well files are typically maintained in chronological order.

This statement is based on the condition of the well file provided in response to SED DR 1, which was a series of single page Pdf documents. SED assumes this first rendition of the file was a perfect copy of the files in the order in which they appeared in the SoCalGas well file on or about October 23, 2015. If this assumption is correct, the well file lacked any discernable order. And in comparing the SS-25 file with the similarly produced SS-25A and 25B well files, there appears to be documents missing from the SS-25 well file, such as Inter-Office memos that might address the ongoing indications of one or more leaks on temperature surveys and any proposed actions or maintenance actions. The SS-25 well file is also missing basic geologic and reservoir data that would normally be acquired during drilling or logging.

SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

25. YOU assert on page 74 of YOUR OPENING TESTIMONY that "SoCalGas records do not show operating records that would be reasonable to keep and mirror typical record

[2] SED's opening testimony states 018010. This is a typo, and is corrected to say 01810.

retention policies in the industry."

a. Identify all "record retention policies" that you contend are typical in the gas storage industry.

SED objects to this question as unduly burdensome. Despite the undue burden of this question, SED ~~requires more time to answer this question, and reserves the right to provide an additional substantive answer.~~

SoCalGas has a record retention policy dated November 30, 2013 that identifies the gas storage records to be kept for the life of the asset plus 5 years. See AC_CPUC_SED_DR_17_000024-25. To date, SoCalGas has not demonstrated to a reasonable degree that it kept all of these records for the Aliso Canyon Storage Facility. Records produced fail to show any organization such that the records would be readily accessible to those who need to access them, especially in the event of an emergency.

Examples of other industry record retention policies are provided as attachments. These policies include references to governing laws and regulations, which SoCalGas can obtain separately through its own library or law office.

1986.0601.GTR0004210_SP_210.4-4_Records_retention.pdf (Redacted)
GasTransmissionSystemRecordsOII_DR_CPUC_023-Q26Atch08_REDACTED.pdf
Pages 34-35.PG&E.P2-2-Guide.to.Record.Retention-2003.pdf (Redacted)

b. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas had record-keeping procedures that were "reasonable" or "mirror[ed] typical retention policies in the industry."

SED objects to this question as unduly burdensome. SoCalGas is the subject of all SED audits identified in the question, and has the information regarding whether it was the subject of any such audits. SED reminds SoCalGas to avoid wasting limited SED staff time with questions to which SoCalGas does or should demonstrably have the answer.

c. Produce all DOCUMENTS regarding "typical record retention policies in the industry."

SED objects to this question as unduly burdensome in asking for SED to produce all such typical record retention policies in the industry because SoCalGas should also have such information. Despite the undue burden of this question, SED ~~requires more time to answer this question, and reserves the right to provide an additional substantive answer.~~

See also attached in response to 25.a.

26. YOU assert on page 68 of YOUR OPENING TESTIMONY that "This failure to maintain basic records led to the inability to maintain wells in safe conditions and to supply critical operating data in response to emergencies."

a. Identify all instances in which YOU contend failure to maintain basic records by SoCalGas "led to the inability to maintain wells in safe conditions." For each such instance, identify the relevant well and record.

SED requires an answer to Data Request 52 Questions 1, 3, 4, 5, 6, 7, 8 and 9 as a condition precedent to providing a complete answer to this question.

b. Identify all instances in which YOU contend failure to maintain basic records by SoCalGas "led to the inability... to supply critical operating data in response to emergencies." For each such instance, identify the relevant well and record.

SED objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of whether failure to maintain basic records by SoCalGas led to the inabilities identified in the question.

Despite the undue burden of this question, SED replies: Please refer to page 131 of the Blade Main Report, March 16, 2019, where Blade Identifies the difference between its determination of the Bottom Hole Pressure ("IPR") compared to the significantly lower pressure SoCalGas gave to DOGGR and the national laboratory for well kill calculations. For further analysis of the results of this difference, see the Blade Report. Records used by Blade for development of the BHP are discussed on pages 128-130 of the Blade Main Report. This discussion points out the problems with some historical data provided to Blade. But, at the basic level, SoCalGas had no current record of the BHP for SS-25, or for the reservoir when Well-SS-25 failed.

Supplementing the above statement. SoCalGas severely underestimated the Reservoir Pressure. (See Blade Vol 3. SS-25 Transient Well Kill Analysis, pp. 10 and 16.) In addition, SoCalGas used an incorrect gas flow of 30 MMscf/D, which should have been in the range of 80 to 93 MMscf/D. SoCalGas' own historical data showed well flow in excess of 80 MMScf/D. (see Blade Vol. 3 SS-25 Transient Well Kill Analysis, p. 37.) These Incorrect figures were apparently used by SoCalGas and Boot & Coots in developing kill procedures that failed. While SoCalGas did not produce evidence of utilizing models prior to kill attempt 7, SED assumes SoCalGas and its contractors, at a minimum, performed calculations to determine the ppg of fluid and pump pressures it would use in each kill attempt. Reservoir pressure, bottom hole pressure and well flow are critical factors in making such calculations. Underestimating these numbers led to repeated well kill failures. A responsible gas stororage operator should have current records that accurately reflect these critical operating data and those records should be readily available to engineering and operating personnel. SoCalGas failed in this respect, creating an

unsafe situation in which conditions at Well SS-25 could not be fully controlled by personnel and where an estimated 120,000 metric tons of methane were released into the atmosphere from the end of October 2015 to early February 2016.

SED requires an answer to Data Request 52 Questions 1, 3, 4, 5, 6, 7, 8 and 9 as a condition precedent to providing a complete answer to this question.

SED Data Request 52 Question 1 asked:

Related to AC_CPUC_0014712-20175 identify by AC.CPUC file number each Cathodic Protection Work Order Report that shows readings on a gas well casing.

SoCalGas's response to SED Data Request 52 Question 1 was non-responsive,

SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the term "readings" and phrase "gas well casing." SoCalGas further objects to this request as overly broad and imposing an undue burden under Rule 10.1 of the Commission's Rules of Practice and Procedure to the extent it seeks to require SoCalGas to search through documents previously provided to SED and in SED's possession.

SED is unable to discern from SoCalGas's answer which exact documents SoCalGas means to be responsive to the question.

SED Data Request 52 Question 3 asked:

Related to AC_CPUC_SED_KITSON_0003008, provide all forms 3466 "Reporting of Gas Blown to Atmosphere" that reported the amount(s) of gas blown to atmosphere associated with the SS25 leak.

"SoCalGas's response to SED Data Request 52 Question 3 was non-responsive and incomplete, stating,

SoCalGas objects to this request to the extent it is vague and ambiguous and seeks information that is outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. The amount of gas blown to atmosphere associated with the SS25 leak was not reported through Form 3466 "Reporting Gas Blown to Atmosphere."

SED Data Request 52 Question 4 asked:
Also related to AC_CPUC_SED_KITSON_0003008, provide all completed forms (please include an ID form number(s) or database name or names) that report the amount of oil discharged to the atmosphere and the amount(s) captured as liquid during the 2015-2016 SS-25 leak.

SoCalGas's response to SED Data Request 52 Question 4 was non-responsive and incomplete, stating,

SoCalGas objects to this request to the extent it is vague and ambiguous and seeks

information that is outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Form 3466 "Reporting Gas Blown to Atmosphere" referenced in AC_CPUC_KITSON_0003008 does not contemplate reporting oil discharge volumes.

SED Data Request 52 Question 5 asked:

Related to AC_CPUC_SED_DR17_0000163, provide (or identify DR response and bates numbers) records referenced in the "5.1 Records" section of Standard 224.02 for Wells SS-25, SS-25A and SS-25B.

SoCalGas's Response to Data Request 52 Question 5 answered:

SoCalGas objects to this request as overly broad, unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. SoCalGas further objects to this request for failing to provide a defined time period to which SoCalGas may tailor its response. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information for the 3 months preceding October 23, 2015. Please see electronic documents with Bates range:

I1906016_SCG_SED_DR_52_0000001 through I1906016_SCG_SED_DR_52_0000036. Additional documents will be provided in an upcoming supplement to this response.

Due to the incomplete nature of this response, SED is unable to analyze it and answer the question at this time.

SED Data Request 52, Question 6 asked:

Also related to AC_CPUC_SED_DR17_0000163, provide daily records for the 3 months preceding October 23, 2015 and ALL records of sacrificial probes, including probe installation, failure and replacement.

SoCalGas's response to Data Request 52, Question 6 answered:

SoCalGas objects to this request as overly broad, unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information for wells SS-25, SS25A, and SS-25B. Please refer to Response 5.

Due to the incomplete nature of this response, SED is unable to analyze it and answer the question at this time.

SED Data Request 52, Question 7 asked.

Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
a. Well Number
b. Installation record showing at least date drilled, depth of well, depth of water from surface.
c. All data collected and recorded from these wells.
d. One map showing location of shallow water wells at Aliso.

SoCalGas responded to this question:

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "shallow water observation wells," overly broad and unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Prior to October 23, 2015, gas storage observation wells SS-5 and W3A were used to monitor pressure in the west and east field areas, respectively. Due to the incompleteness of this answer in failing to address subparts b, c, and d of Data Request 52, Question 7, SED is unable to answer this question at this time.

SED Data Request 52, Question 8 asked:

Related to AC_CPUC_SED_DR17_0000185, provide all records referenced in Section 5.1 collected, calculated and plotted during 2014-2015 for Aliso Canyon Storage Unit. Please state what form these records are kept in and where they are stored.

SoCalGas responded to Data Request 52, Question 8 as follows:

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "Aliso Canyon Storage Unit," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the Aliso Canyon Gas Storage Field. Please see electronic document with Bates range: I1906016_SCG_SED_DR_52_0000037.

SED is unclear how this document responds to the question asked. Therefore, SED assumes from this response that SoCalGas is not maintaining the records per its own Standard.

In Data Request 52, Question 9, SED asked,

In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log

interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In response, to this question, SoCalGas stated,

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "SIMP Model Studies" and term "similar," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the SIMP Pilot Project. Please refer to SoCalGas' response to SED Data Request 25 ("DR-25") dated August 14, 2018. The request is for records of Surface Pressure taken during shut-in, calculations and Plots. The documents provided may contain some of the information, but do not appear to fit the Records requirement in their Standard.

Rather than providing an answer to a direct specific question, DR 25 response is a data dump, of over 1500 documents in the middle of which SED found the SIMP Model Study report. Due to the non-responsive answer of SoCalGas, SED is unable to provide a further answer to this question at this time.

SED had asked the questions in DR 52 to gain a clearer understanding of how SoCalGas keeps records. Because SoCalGas did not provide any substantive responses, SED will assume SoCalGas either does not have responsive documents or, if it does, the documents cannot be found due to poor recordkeeping practices.

c. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

SED objects to this question on the grounds that it mischaracterizes SED's testimony. SED does not use this point as the violation of Section 451. Instead, the violations are identified at the end of the section in which this sentence is found. Namely, the recordkeeping related violations in this section are articulated on SED opening testimony page 75, and state,

> In conclusion, SoCalGas' imprudent and unreasonable record keeping practices violated Section 451 three times; once for well SS-25, a second time for well SS-25A, and a third time for well SS-25B. The violation associated with well SS-25 begins June 6, 1973, the date that SoCalGas hydrotested their gas conversion of well SS-25. The violation associated with well SS-25A began December 7, 1972, the date that well SS-25A became operational according to DOGGR records. The violation associated with well SS-25B began October 29, 1973, the date that well SS-25B became operational according to DOGGR records.
>
> Each of these three violations end on October 23, 2015, as safety records in Well Files SS-25, SS-25A and SS-25B appeared to be missing up through the date of the well SS-25 incident.

27. YOU allege that SoCalGas knew that SS-25 released both crude oil and natural gas during the ALISO CANYON incident, but "did not disclose this fact to the Los Angeles County Department of Health." (OPENING TESTIMONY, page 51).

a. Identify all actions taken by YOU to independently verify the claims alleged by the California Department of Public Health ("DPH").

SED objects to this question on the grounds that it is unduly burdensome and overly broad, requiring SED to identify all actions it took to independently verify the claims alleged by DPH.

Notwithstanding these objections, SED requires more time to answer this question, and reserves the right to update its answer.

b. Confirm or deny that YOU considered SoCalGas' March 21, 2019 response letter to the DPH when preparing YOUR OPENING TESTIMONY.

SED objects to this question to the extent it requests information that is protected by attorney-client and work product privileges. Without waiving these privileges, the answer is yes, as shown in SED's opening testimony on pages 51 and 52. Specifically, the passage in SED's testimony that shows SED considered SoCalGas's response letter to DPH states,

"SoCalGas responded to the Department of Public Health asserting 'For all the above reasons, your suggestion that SoCalGas somehow withheld information or was otherwise not fully transparent with respect to the components of natural gas released during the incident, and your statements concerning DPH's ability to perform a health assessment, are simply incorrect.'" SED's testimony references the March 21, 2019 letter in footnotes 383 and 384 of its opening testimony, which are cited in this passage.

c. Produce any and all COMMUNICATIONS by and between SED and the DPH, from October 23, 2015 through and including December 6, 2019.

SED objects to this question on the grounds that it requests information that is protected by the common interest privilege.

d. Produce any and all internal CPUC COMMUNICATIONS concerning DPH related to ALISO CANYON, from October 23, 2015 through and including December 6, 2019.

SED objects to this question on the grounds that it requests information that is protected by attorney client and work product privileges. SED also objects to this question on the grounds that it is unduly burdensome.

28. YOU allege that SoCalGas "did not have a well specific, well control plan that considered transient kill modeling or well deliverability. There was not quantitative understanding of well deliverability, although data were available, and well-established

industry practices existed for such analysis." (OPENING TESTIMONY, page 28).

a. Identify the "well-established industry standards" you reference on page 28 of YOUR OPENING TESTIMONY.

SED objects to this question as mischaracterizing its testimony, which uses the term "well-established industry practices"; not "well-established industry standards". SED understands the question to be asking about "well-established industry practices", and will answer the question with this understanding.

This statement is based upon excerpts quoted from the Blade Report, pages 5 and 238.

b. Identify and produce all DOCUMENTS, aside from the Blade Report, that include or reference the "well-established industry standards" you identify in response to Request 28(a).

SED further objects to this question as unduly burdensome in that it requests SED to gather all documents that include well-established industry standards.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

For reference to "simulations," a term used before "modeling" but essentially the same thing, refer to Donald L. Katz, AIME, U. of Michigan, "Monitoring Gas Storage Reservoirs," June 10, 1971, SPE PAPER No. 3287.

c. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

SED objects to this question as mischaracterizing its opening testimony. The violations in this section are identified in this section on pages 38 and 39, and are quoted here.

> Given that SoCalGas had no well kill control plans and there are no data indicating transient modeling -- any modeling -- or analysis conducted to design the second through sixth well kill attempts, and such modeling would have provided the necessary information to successfully kill the well, SoCalGas violated Section 451.
>
> The Section 451 violation began November 13, 2015, the day SoCalGas unsuccessfully executed the second well kill attempt without modeling, and continued through February 11, 2016, the date of the successful relief well kill attempt. Because the second through sixth well kill attempts should have been successful with proper modeling, shareholders should be required to pay all expenses associated with each one. Also, because the relief well was started on December 4, 2015, after the second well kill attempt, the relief well would not have been needed had the second well kill attempt

been properly modeled. As such, shareholders should be required to pay all expenses associated with the relief well. SoCalGas's failure to provide well kill programs for relief well #2, well SS-25A and well SS-25B each constitute one violation of Section 451, for a total of three violations. Each of these violations span from November 13, 2015, the date
SoCalGas unsuccessfully executed the second well kill attempt, to February 11, 2016, the date of the successful relief well kill attempt.

Because surface plumbing failures prevented the well from being kept filled and the wellhead and surface casing were structurally unstable by kill attempt 6,276 such damage appears to have resulted from the prior unsuccessful kill attempt, thereby compromising the ability of kill attempt 7 to kill the well and end the safety consequences of the SS-25 leak. According to Blade, pumping for kill attempt 7 was terminated due to rocking of the wellhead and a subsequent failure of the injection connection. In other words, the ability to succeed on the seventh kill attempt was impaired by at least certain of the prior unsuccessful kill attempts, which should have been successful. This is a violation of Section 451.

The apparent conservative start date of this violation is November 25, 2015, the date that well kill attempt #6 was made. This violation continued until February 11, 2016, the date of the successful relief well kill attempt.

The basis for these violations is provided in the SED's opening testimony, Section II.B.5, pages 28 to 39.

29. YOU allege that the Division of Oil, Gas and Geothermal Resources ("DOGGR") responded to a 1994 SoCalGas proposal by stating, in part, "'Therefore, the monitoring program and static temperature surveys currently used by the Gas Company could be used to satisfy compliance of the requirements for mechanical integrity found in this section [California Code of Regulations Section 1724.10(k)(5)].'" (OPENING TESTIMONY, page 15). Do YOU disagree that DOGGR affirmatively stated that SoCalGas' activities complied with the cited regulation? If so, identify all grounds for your position.

SED's position is precisely that from SED testimony page 15, which SoCalGas quoted in the question. The grounds for the position is shown in the quote, and based upon the Blade Report at page 198, as cited in footnote 75.

30. Do YOU contend that YOU have authority to fine utilities for actions that are not within SED's regulatory purview, but instead are regulated exclusively by DOGGR?

SED objects to this question on the grounds that it calls for a legal conclusion as to SED's authority and SED's regulatory purview, as well as the exclusive regulatory purview of DOGGR. SED further objects to the question as argumentative, that it assumes facts not in evidence, that it mischaracterizes SED's testimony, that it is vague and ambiguous in that it fails to

provide context, vague as to time, and that it is overly broad.

31. Provide all contracts SED is aware of between underground gas storage operators, entered into during an emergency situation, that include a provision requiring the contractor to subject itself to the same provisions to cooperate with an investigation, by a regulator that has no jurisdiction over the contractor, as the principal.

SED objects to this question as vague in that it does not reference a page of SED's testimony; vague as to time; overly broad in asking for SED's awareness of all underground gas storage operators, including those not regulated by the Commission; and unduly burdensome.

Ex. I - 10

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon Storage Facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility. (U904G).	I.19-06-016 (Filed 6-27-19)

DEPOSITION OF MARGARET C. FELTS
Los Angeles, California
Wednesday, February 5, 2020
MORNING SESSION

Reported by:
LINDA RYAN
CSR No. 9915
JOB No. 311652

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon Storage Facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility. (U904G).	I.19-06-016 (Filed 6-27-19)

Videotaped Deposition of MARGARET C. FELTS, pages 1 through 326, taken in accordance with Article 10 of the Commission's Rules of Practice and Procedure, taken on behalf of the Southern California Gas Company, at 300 South Grand Avenue, Twenty-Second Floor, Los Angeles, California, beginning at 9:23 a.m. and ending at 8:39 p.m. on Wednesday, February 5, 2020, before LINDA RYAN, Certified Shorthand Reporter No. 9915.

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Also Present:
KAREN SHEA, SED
HEIDI FIELDING, Videographer

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Los Angeles, California

Wednesday, February 5, 2020

9:23 a.m. - 12:15 p.m.

PLEASE BE ADVISED THAT THE DISMANTLING AND/OR UNBINDING OF THE ORIGINAL TRANSCRIPT WILL VOID THE CERTIFICATION OF THE CERTIFIED SHORTHAND REPORTER AND NULLIFY THE INTEGRITY OF THE ORIGINAL TRANSCRIPT.

THE VIDEOGRAPHER: Good morning.

Here begins media number one in the deposition of Margaret C. Felts, Volume 1, in the matter of Aliso Canyon Storage Facility. This case is before the Public Utilities Commission of the State of California, the case number is 1.19-06-016.

Today's date is February the 5th of the year 2020 and the time on the video monitor is 9:23 a.m.

This deposition is taking place at 300 South Grand Avenue, 22nd floor, in Los Angeles, California 90071-3132, and is being taken on behalf of the Defendants.

The videographer is Heidi Fielding, appearing on behalf of Biehl, et al., Certified Shorthand Reporters.

The certified stenographic reporter preparing the official transcript of today's deposition is Linda Ryan, appearing on behalf of Biehl, et al., Certified Shorthand Reporters.

Neither the reporter nor myself are employees of Biehl, et al., Certified Shorthand Reporters.

Counsel, would you please identify yourselves and state whom you represent.

MR. STODDARD: Jack Stoddard for Southern California Gas.

MR. MOSHFEGH: Pejman Moshfegh also for Southern California Gas.

MS. PATEL: Avisha Patel on behalf of Southern California Gas.

MS. MORTAZAVI: Setareh Mortazavi on behalf of Southern California Gas Company.

MR. GRUEN: Darryl Gruen on behalf of the Safety Enforcement Division of the California Public Utilities Commission.

THE VIDEOGRAPHER: And if our court reporter would please administer the oath to the witness.

(Witness sworn.)

THE WITNESS: I do.

THE VIDEOGRAPHER: Please begin.

MR. STODDARD: Thank you.

MARGARET C. FELTS,
having been first duly sworn
and administered an oath
pursuant to California CCP 2094,
was examined and testified as follows:

EXAMINATION

BY MR. STODDARD

Q Would you please state your name and your home address.

A Margaret C. Felts. And I live at 633 Dodge Street, Delta, Colorado 81416.

Q Thank you, Ms. Felts.

And is this the first time you've ever been deposed?

A No.

Q How many times have you been deposed before?

MR. STODDARD: One moment, brief break.

THE VIDEOGRAPHER: Do you wish to go off the record, Counsel?

(Whereupon Ms. Shea entered the deposition proceedings.)

MR. STODDARD: Yes, please.

THE VIDEOGRAPHER: Just a moment.

We are off the record at 9:26 a.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 9:26 a.m.

MR. STODDARD: Ms. Felts, apologies.

Before we get into the questioning, we're going to address a few initial housekeeping items for purposes of the record.

The first is that we had had prior discussions regarding reimbursement or compensation for Ms. Felts' appearance today.

SoCalGas agrees to pay for -- pay Ms. Felts directly for her time in appearing in today's deposition and -- with the understanding that SED will pay for her travel time as well as travel expenses.

MR. GRUEN: Thank you.

And just for the record, SED notes SED does not stipulate to paying for Ms. Felts' travel expenses or other expenses related to the deposition today, and SED reserves the right to request an ALJ ruling requiring Southern California Gas to pay for those expenses; so that's for the record.

A couple of other items.

SED will be requesting copies of the videotape of today's deposition of Ms. Felts as well as the transcripts of the deposition.

And just for the record, we'll note objections as we see appropriate if we -- if we think they're appropriate.

But for the record, we -- I'm in receipt of, for Ms. Felts, a copy of her testimony in Southern California Gas Company's and San Diego Gas & Electric Company's Application 1509013, which is her testimony for UCAN, a party that counsel is not present today.

And our understanding is that any questions related to that testimony is for the sole and exclusive purpose of the noticed deposition on the Aliso Canyon Order Instituting Investigation and Order to Show Cause, and that anything that Ms. Felts says today should not -- it's not appropriate to use anything she says related to that testimony in a 1509013 in that proceeding; so we'll note objections accordingly, but we wanted to make that clear for the record at the outset.

MR. STODDARD: Noted.

And SoCalGas's response on that is that SoCalGas doesn't waive any right to ask a question about any document or issue within Ms. Felts' scope

of knowledge or area of expertise or prior testimony or any other document; however, we note your objection regarding the use of that transcript for purposes of the PSRP proceeding.

MR. GRUEN: Your point is noted as well.

Thank you.

BY MR. STODDARD:

Q Okay. Ms. Felts, thank you. I believe we had just gotten through your name and home address.

And I had asked whether you had been deposed before and you indicated that you had been. And then I had asked how many approximate depositions had you submitted to, and I don't believe I had an answer to that question. But if I did, I apologize.

A And I don't have a number, but it's less than ten.

Q Less than ten. Okay.

And do you have an approximate number of those where you would have been an expert witness for purposes of the deposition?

A All of them.

Q Okay. So this isn't new to you, so I'm going to, you know, recount a few kind of rules of the road for the deposition. They will all be familiar to you I'm sure.

But first and most importantly, please speak clearly and slowly, and I will try to do so as well. Please respond verbally to any questions.

The court reporter can't capture nods or gestures; so make sure that you answer with words, "yes," "no," or otherwise.

The court reporter can't capture what we're saying if we're interrupting each other and talking over each other; so please don't interrupt me, and I will try not to interrupt you.

Wait until the question is asked before you answer it, and I will wait until you finish your answer if I can before I ask my next question.

Also, in general, your attorney may state objections for the record. But you should still answer the question unless you're specifically directed by your attorney not to answer the question.

And finally, in terms of breaks, we're going to plan on taking a break, you know, probably approximately at least every hour, but if you need a break at any time, just say so. But please answer any question that was asked prior to taking a break.

A Okay.

Q And Ms. Felts, are you represented here by counsel today?

A Yes.
Q And who is your counsel?
A Darryl Gruen.
Q Thank you.
And is Mr. Gruen representing you in your personal capacity?
MR. GRUEN: I'm sorry, just to -- maybe to clarify for the record.
Is the question whether --
Just to clarify maybe you could ask is -- whether she is being represented as a witness for SED or personally.
BY MR. STODDARD:
Q Ms. Felts, today here you are appearing as a witness for SED; is that correct?
A Yes.
Q And so Mr. Gruen is representing SED and you as a witness for SED, correct?
A Yes.
MR. STODDARD: Thank you.
I'd like to mark Exhibit 1-1.
(Deposition Exhibit 1-1 was marked for identification and is attached hereto.)
BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?
A Yes.
Q This is a deposition notice asking for your appearance here today; is that correct?
A Yes.
Q If you can turn to page 3 of the document.
Do you see where it asks for documents to be produced?
A Yes.
Q And the first request is for "All work papers not previously produced to SoCalGas that Margaret Felts generated or relied upon in connection with the above captioned matter."
A Yes.
Q Do you see that?
Did you collect documents in response to that request?
A Everything was already provided to you.
Q Okay. So would it be accurate to say that we have -- that all work papers that would be responsive to this request have been collected and provided to SoCalGas prior to today's deposition?
MR. GRUEN: Let me just note an objection for the record, and I think we had agreed to this, that the definition of "work papers" excludes anything

that would be used for future testimony, such as the reply or the rebuttal testimony. And we understand the definition to be qualified in such a way that it's only applying to the testimony that Ms. Felts has produced in this proceeding thus far.

MR. STODDARD: Objection noted.

I'm going to restate the question and ask that Ms. Felts answer it.

Q I'll break it into two different questions though.

First, all work papers that were generated prior to service of your opening testimony or SED's opening testimony in this proceeding, were those collected and produced to SoCalGas prior to today's deposition?

A Yes.

Q Okay. And have you generated additional work papers since then, since service of your opening testimony that were not produced for purposes of today's deposition?

MR. GRUEN: Again, I'm just going to object on the grounds that those questions -- questions related to work papers since the production of testimony are protected on the grounds of attorney-client or -- and/or work product privilege; so I'm going to

instruct the witness not to answer the question, the second question.

BY MR. STODDARD:

Q Okay. Ms. Felts, question number 2 requests all written testimony or reports that you prepared related to underground storage facilities, correct?

A Yes.

Q And did you collect and produce any written testimony or reports as requested by that item?

A I looked for testimony in the Montebello Storage Unit case, but I don't have that file anymore; so I don't have it. I think I produced testimony at the time. I don't have a copy of it.

I also have some documents related to the Playa del Rey case that I worked on. I don't believe a final testimony was ever published in that case. I think it was settled.

MR. STODDARD: Thank you very much.

All right. I would like to mark Exhibit 1-2.

(Deposition Exhibit 1-2 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.
Q And this is your resume, correct?
A Yes.
Q This is the resume that you produced to SoCalGas and which you included with your -- with their testimony; is that correct?
A Yes.
Q I'd like to ask you a few questions about this.
First -- the first sentence of this document states that you serve as lead technical consultant to law firms, regulatory agencies and private entities on environmental, energy and corporate fraud cases concentrating on behind-the-scene discovery, research and strategy development.
Do you see that?
A Yes.
Q Are there any current matters aside from the one that we're here for today that you're working on?
A Yes.
Q Are you able to tell us about those matters?
MR. GRUEN: Just note an objection to the extent that they're unrelated and irrelevant to the proceeding at hand, Aliso -- to the Aliso Order Instituting Investigation and Order to Show Cause.

But she can go ahead and answer.

MR. STODDARD: Yeah.

We don't know whether they're relevant or not unless we know what they are.

MR. GRUEN: Understood.

THE WITNESS: There are two cases that are open:

One has to do with a leaking gasoline pipeline owned by an oil company in the east, in Pennsylvania, it's a private matter; so that's about as much as I can tell you.

BY MR. STODDARD:

Q You said a gasoline pipeline?

A Yes.

Q Like automotive fuel?

A Yes.

Q Okay. And you said that's in the east; is that correct?

A It's in Pennsylvania.

Q And that's a private matter between two corporate entities?

A It's between a land owner and the oil company.

Q And which party are you working for in that case?

A The private --

The plaintiff.

Q Okay. And are you a consulting expert in that case or testifying expert?

A Both.

Q "Both." Okay.

And you said there was another case?

A A small property issue in Northern California having to do with, again, a private land owner and PG&E. I'm representing --

I'm the expert for the plaintiff, the land owner.

Q Okay. And does that relate to PG&E electrical facilities?

A No, it's PG&E gas.

Q It's related to PG&E Gas. Okay.

Does it involve a gas storage facility?

A No. Pipeline.

Q Okay. Ms. Felts, I'm going to direct you down to the next section where it says "Specialties." And it says "Discovery and technical strategies for complexion cases involving," and then it lists a variety of subject matter areas.

Do you see that?

A Yes.

Q What sorts of discovery and technical

strategies do you specialize in?

A I write discovery questions, and I help with developing a strategy based on data that has been collected or been provided. I also do research to supplement that with additional information.

Q What sort of research?

A Technical research or flush out the issues of a case, help attorneys understand technical issues.

Q Thank you.

Under the next bullet which states "Gas and Electric Utilities regulatory cases," it states "Records Management Assessment" under the first sub bullet there.

Do you see that?

A Yes.

Q What exactly is "Records Management Assessment"?

A To do a records review to see if the recordkeeping practices are in keeping with standard or what would be expected in the industry that the case is working in.

Q Thank you.

The next bullet down -- or two, I'm sorry, skip it, says "Fraud" and then "Incident Assessment."

A Yes.

Q What do you mean by "Incident Assessment"?

A So if there was a spill, say I would do an assessment of the records and the data that resulted from that or transcripts or whatever is -- whatever records are available, and assess the situation from the beginning to the end and probably develop a report to whoever I was working for, usually an attorney.

Q Okay. So in the context of incident assessments it would be fair to say that your review or investigation is based on examination and collection and review of records and documents?

A Yes.

Q And that you would prepare a report or testimony in those cases?

A Usually at that level an incident assessment in my mind would occur very early on. When somebody contacts me, I look at what they have.

Maybe look at news media or reports or whatever I can -- information is available and then do a short report or -- like an interim report to the attorney that gives them an idea of what I think -- what I think the incident information provides and what -- where the case might go on a technical level,

not on a legal level.

Q All right. Underneath that bullet you see where it says "Pipeline Integrity Assessment"?

A Yes.

Q Can you explain, please, what do you mean by that in this context?

A Well, again, so we're looking at records that have to do with a pipeline and whether or not the condition of the pipeline was sound or if there was an issue with the pipeline that can be identified early on as part of the case.

Q Based on the records?

A Yes.

Q Okay. And for "Underground Gas Storage Assessment"?

A Similar. Similar to the pipeline assessment, you just --

It's based on record reviews.

Q And what are you assessing relative to underground gas storage in that case?

A Well, it would depend on what the issue is because they seem to vary quite a bit. But it would be usually some sort of a gas leak from the storage unit. Sometimes a combined environmental issue that, you know, evolves from a complaint from a neighbor or

neighborhood or somebody that lives near an underground storage area.

Q Okay. Does it include assessment of gas storage wells?

A Yes.

Q Okay. And in all of these instances, you have four different, or I guess five different items here are described as assessments, "Records Management Assessment, Incident Assessment, Tree and Pole Program Assessment, Pipeline Integrity Assessment," and "Underground Storage Assessment."

For each of these, these are based upon your review of records?

A Yes.

Q So not direct examination of physical evidence?

A In the tree and pole program assessment, I actually went out and did physical inspections in some instances.

Q Okay. On any of these assessments, do you interview people or witnesses?

A Not without an attorney present with me.

Q Okay. The next bullet down below that bullet is "Oil & Gas Industry Cases."

Are these generally similar to what we've

covered in underground gas storage assessment and pipeline assessment, or is this a different category of cases in your view?

A This is a category that I have not worked in for quite some time; I would say for at least 15 years. Where previously I was doing work in oil price projections, oil price setting or oil and refinery product price setting. There was -- there were quite a few different types of issues that were coming up that I was hired to review or help on. I haven't done that for a long time.

Q By "price setting," do you mean price fixing?

A Yes.

Q Okay. And this related to --

Were these regulated oil and gas companies? Or I guess let me restate that. I'm sorry.

Does this involve public utilities?

A No.

Q The next bullet down is "Natural Gas Supply and Demand Assessment."

Do you see that?

A Yes.

Q Can you describe what this work entailed?

A Again, this is an area that I haven't really

worked that much in recently, but in the 1980s and '90s, I worked quite a bit on that, and it had to do with assessing the available supply of natural gas and forecasting the supply and demand curves.

Q And was this related to supply of natural gas regionally?

A It was supply of natural gas within the United States, and it would have included Mexico.

Q Okay. So this was kind of a broad market analysis?

A Yes, because your pipeline is connected. I mean, the supplies cross borders; so it can't be just California. It would have to be nationally and in some instances international.

Q Because the natural gas pipeline system is integrated?

A Yes.

Q Kind of almost at the continental level?

A Yes.

Q And so a significant natural gas resource or piece of infrastructure is impacted by even relatively far flung demand across the country; is that correct?

A Well, I don't know if you have far flung demand. And the demand curves turn out to be fairly

consistent from one year to the next.

But there was a period of time when there were some entities who believed that either natural gas demand was going to go way up or way down, and so there would be a call for some sort of a forecast. And this is early -- probably before the year, I want to say 2000, because sometime around 2000, 2004 the Energy Information Administration stepped in and started providing some pretty good sound information, data, and forecasts that people could access easily. And it was easier for me to give people a link to that than to try to generate my own forecasts; so that demand for that work diminished.

Q The next bullet down is "Groundwater Contamination."

Can you please explain the work that you've done in that area?

A In the 1990s -- approximately 1990 to about 2000, I had an environmental company with employees, and we did environmental assessments and investigations, mostly having to do with groundwater.

And then year -- some time around 1998 to about 2002 I did a research project for Lloyds of London. And the basic question was who knew what, when about groundwater contamination in California

primarily, but it ended up extending throughout the United States.

And that review, I researched records back to I think it was 1895 and forward and developed a huge database about groundwater contamination.

Q So was the work that you were doing on groundwater contamination records-based work or was it field work?

A It was --

So the work that I did as a consultant was field work. We actually drilled and constructed groundwater monitoring systems. The research for Lloyds of London was records-based.

Q Okay. And was the groundwater contamination work you did particular to energy?

A No.

Q Okay. The next item you have on the list is "Hazardous waste disposal and site cleanup," with sub bullets for "CERCLA, RCRA" and "Underground Storage Tanks."

Do you see that?

A Yes.

Q What types of underground storage tanks did this concern?

A Gasoline, diesel, and anything else that was

in a tank below the ground.

Q Okay. This does not relate to natural gas storage fields, however --

A No.

Q -- correct? Okay.

All right. Moving over to your employment history. The first item that you identify is "Litigation Consultant 1983 - Present."

Do you see that?

A Yes.

Q I would note that that period of time overlaps with a number of other positions listed on your employment history.

A Yes.

Q Did you work both as a litigation consultant at the same time that you were employed by others?

A Yes. During that period of time there was only a -- there was a period of about five years when I worked for the California Communications Association when I was not working any active litigation cases. I had a couple that were sort of in remission that came alive later, but I wasn't working on them during that five years.

Q Was there any particular reason why you didn't take on cases during that period of time?

A Well, no particular reason. I think I was just busy doing work with the telephone companies and the association.

Q Okay. The next item down the list --

So we just discussed the California Communications Association.

From 1995 to 1997 you were a senior consultant for Dames & Moore; is that correct?

A Yes.

Q And what was your role there?

A I was just an engineer. I ran an engineering group in Northern California. We worked cases -- I worked cases in Washington state and Northern California. My team worked other cases in mostly Northern California, some in San Francisco, Bay area cases.

Q What sorts of engineering?

A Well, some were -- some of it was environmental engineering. There was air emission cases. There was groundwater cases.

Q Okay.

A There were permits that were being applied for having to do with complicated construction.

Q Okay. The next item down says --

MR. GRUEN: I'm sorry, I just want to clarify.

Are you finished answering that question?

THE WITNESS: Yes.

MR. GRUEN: Okay.

BY MR. STODDARD:

Q The next item down shows that from 1993 to 1995 you were the Deputy Director at the California Department of Toxic Substances Control; is that correct?

A Yes.

Q Can you describe your work there during that time period?

A I was in charge of the statewide site mitigation program; so we handled oversight of Superfund sites, state equivalent of Superfund sites. So those would be all funded and handled with -- by my team.

And then we had oversight over all of the hazardous waste site mitigation or cleanup, investigation and cleanups by private parties that were over -- you know, overseen by the state. And then I had an emergency management -- or emergency response group that handled response to emergencies that involved hazardous waste.

For instance, if a storm came in and washed a bunch of propane tanks down a river, we would go

out and deal with the problem. It was on-site work. And we also handled all of the drug lab cleanups.

Let me think.

We had a geologic group that did geologic assessments for site -- contaminated sites.

Q Did any of that work, as you recall, relate to natural gas facilities or natural gas?

A So if there was a complaint that came in for exposure to natural gas, we would have a team respond to it.

But typically anything having to do with a natural gas storage would be deferred to the lead agency, which would probably be the Public Utilities Commission or the Division of Oil and Gas. But we might join a team for an assessment on a site.

Q Do you recall any specific such cases?

A No, not offhand.

Q Your tenure there was fairly short, for two years.

Was there any particular reason that you left after two years?

A It was a political appointment.

Q Similarly your tenure at Dames & Moore was from 1995 to 1997.

Was there any particular reason that you

left that position after two years?

A They offered me a job, and I was in transition back from a political appointment to a consulting firm, and they agreed that I could sort of ride on their coattails while I made that transition; so I went to Dames & Moore. I pulled my old clients and worked to shift back out.

Q Okay. Jumping down to Division Chief of Engineering under the Department of Defense McClellan Air Force Base, 1985 to 1990.

Do you see that?

A Yes.

Q Can you please tell us a little bit about that work?

A Okay. So McClellan Air Force Base had a very bad contamination problem. It's an Air Force/Army flight depot, and for years they had been discarding all of their chemical waste into big pits on the west side of the base.

So they were challenged with trying to do something about cleaning up that when it started contaminating groundwater wells west of the base. And they hired me to come on initially to consult with them about what to do about the groundwater contamination.

They immediately offered an employment position, which turned in to a job of not only dealing with the immediate problem but of developing a model environmental program for the Department of Defense; so I helped them set that up. And I started in the Superfund side.

I got that going, and I moved over to the RCRA program and implemented that. Then I was in charge of the air emissions program in addition to RCRA; so basically I was writing and developing programs to put that in place. And then that was -- that program was proliferated to the rest of the depots and later to the rest to the Department of Defense facilities.

Q Okay. And did that job have any involvement with natural gas infrastructure facilities?

A No.

Q The next item down is "Environmental Contractor Invictus Corp." There is no time period for this.

Do you have a time period?

A That was my own company. 1982 to '85.

Q And this is the -- is this the same company that you were referring to when we were discussing groundwater contamination work under "Specialties"

before?

A Yes. And it had another name. It was -- seems like it started out as Clemen Environmental Services and may have continued to exist during the time I was at the Department of Defense.

Q The company continued to exist?

A Yes.

Q So this is a company you started and then left when you joined the Department of Defense?

A Well, I mean it was my own company.

So if you look at this, it started in 1993 as Clemen Environmental Services, and then I continued to carry contracts, consulting contracts, including with the PUC while I was at McClellan at the Department of Defense.

Q I'm sorry, can you slow down for one moment. I think you said you see where it references Clemen in 1993. And I don't see --

Forgive me if I'm missing it, but I don't see where you're pointing to on the document.

A I'm sorry, Deputy Director 1993 to 1995.

Q Yes.

A Okay. So Division Chief of Engineering is 1985 to 1990 so there is a three-year period in there. That was also an active environmental period

which would have been under Invictus Corporation.

Q Okay. So --

A So I'm saying, okay, let's --

The starting date for Clemen Environmental Services, which is Invictus Corporation, because that was before it was incorporated, is 1983. And so if you put 1983 to 1993, that would be the period of time that the dates that would go behind Invictus Corporation.

Does that make sense?

Q So just to confirm, the dates that should go immediately to the right of the environmental contract line should be 1983 to 1993?

A I think that's the best.

Q Okay. And the Invictus Corp work continued for a period of three years while you were also Division Chief of Engineering for the Department of Defense?

A Yes.

Q Okay. And you indicated that you had contracts with the PUC?

A Yes.

Q That was with Invictus?

A The contract itself was either with Clemen Environmental Services or Invictus. I actually don't

remember the date of the incorporation for that and the name change. But it's all the same thing. It was a private company that was then incorporated in the State of California and then the name --

Q How do you spell Clemen?

A C-L-E-M-E-N.

Q So Clemen is not identified on here. Invictus Corp is.

But Invictus Corp and Clemen are one and the same?

A Yes.

Q How many appointments did you have with the California Public Utilities Commission approximately?

A Well, let's first finish the dates on that one.

So you had to 1993, and then I picked it up again in 1997 to about 2004; so add those dates to the line outside of environmental contractor. And the number of PUC cases, I've never counted those.

Q Approximate, would you say it was, you know, more than 20 contracts?

A I'd say it's right around 20.

Q Okay. And all of these contracts related to groundwater contamination matters?

A No. They -- they were across the board; so

there was a gas plant case, a coal-fired power plant, Helms power plant, which is water storage.

There were three fraud cases involving utilities. There was tree trimming case and pole maintenance. There were two underground storage cases, which was Montebello and Playa del Rey.

Q So I apologize, I don't mean to interrupt, Ms. Felts.

But just to summarize, because I think we will get into some of this in a moment. But to clarify, because I hadn't appreciated this before, the contracts between Invictus and PUC were for expert services?

A Yes.

Q So it wasn't related to engineering work specifically, engineering services related to the groundwater contamination?

A No.

Q Okay. But Invictus also did that work?

A Yes.

Q Not for the PUC?

A Yes.

Q Okay. Was any of --

Do you recall any of the contracts with the PUC for Invictus being for work other than expert

consulting or testifying services?

A No.

Q Okay. Thank you.

Next item down briefly, do you recall the tenure and the dates for "Energy Specialist" at the "California Energy Commission"?

A I think I was there from 1980 to 1983, I think. Late '80 to '83, early '83.

Q And what was your role as an energy specialist?

A I was in charge of the group -- I don't remember the name of the group. It was in -- it was the fuels office, and I was in charge of natural gas and refining forecasts.

Q This was forecasting work related to supply and demand?

A Yes.

Q So this did not relate to energy infrastructure integrity?

A No.

Q Or to particular incidents?

A No.

Q Okay. Next item down it identifies you as a process engineer for Celanese -- apologies if I mispronounce this, Celanese Plastics and Specialties?

A Yes.

Q What did you do as a process engineer?

A I was one of two engineers at a plant in West Texas, Vernon, Texas that manufactured guar powder, which was produced in mass specially for the oil industry for fracking.

Q What was your specific role with respect to the production of guar?

A Well, it was an interesting process plant where we -- I had to grind a bean basically -- guar is an agricultural product, and we had to grind it into a dry powder; so in the meantime in order to get the properties that were required of that powder as an end product, it had to go through a reactive process where there was a chemical reaction to give it those properties.

So I was in charge of the process from front to end to get that to happen and just day-to-day engineering problems at the plant. And also handled environmental problems related to their waste treatment and air emissions.

Q And how many years were you in that position?

A About two.

Q And finally it appears that you were a

process engineer for Amoco Oil Company in Yorktown. Is that Yorktown, Pennsylvania?

A Virginia.

Q "Virginia"?

What did you do as a process engineer for Amoco?

A Again, worked a variety of refining engineering projects; so I was trained to run their linear program on the major -- on the mainframe, which was linked to I think Whiting.

Anyway, they had five refineries so the mainframe linear program was set up so that all of the oil movements that went from one refinery to the other and the production of the products was coordinated.

And so I was in charge and spent a lot of my time managing the inputs and outputs of the refinery and making sure that those specs of the products met the requirements for the outgoing demand; so we had a large product slate. It was a full-fledged refinery, and everything had to balance. And then also dealt with the blending of crude oils, because at that refinery we were using both domestic crude and foreign crude. And so it was an interesting project.

Q And how long were you in that position?

A About three years.
Q Okay. And was that your first job out of graduate school?
A Out of engineering school.
Q Out of engineering school.
What year do you recall you would have started that? Would it be '70 -- mid-'70s?
A 1977.
Q Okay. And then below that we see "Education," and it appears that you are an attorney, and you got your law degree from the Pacific McGeorge School of Law; is that correct?
A Yes.
Q And you got your MS in energy environmental engineering from LaSalle?
A Yes.
Q Are there any other degrees that aren't listed on here?
A No. I have a certification in linear programming.
Q Certification, any other certifications we should be aware of?
A No.
Q Any other certifications at all?
A I have a general engineering license that is

not on there. It's currently on hold with the State of California.

Q What does that mean?

A It means I pay less because I'm not using it; so it still could be activated in a day if I went down and paid them the extra money.

Q Do you have an engineering license that is active in another jurisdiction?

A No.

Q Okay. Are you --

It identifies you as having a Washington State Bar number.

Is that active or is that inactive?

A Active.

Q Active.

And you're a member of the Phi Delta Phi International Legal Fraternity. Is that a membership or an honor?

A It was an invitation. I have a lifetime membership in it. It's --

Q Impressive.

All right. Turning to the next page, and we'll touch on a few of these but not all.

First question is the first case here identified "2018 - 2019 Oil Company Pipeline Leak,

Client: Private Law Firm."

A Yes.

Q Is this matter concluded in 2019?

A No. It's still open.

Q It's ongoing. Okay.

And is this the same matter -- no, this is an oil pipeline not gasoline.

A It's the same matter.

Q It's the same matter?

A Yes.

Q So this is a gasoline company pipeline leak?

A It's an oil company that owns a gasoline pipeline. They own other pipelines too.

Q All right. And are you able to tell us who the private law firm is?

A No.

Q Okay. Below that, "2016 - 2018 PG&E General Rate Case FERC Docket." I won't read the docket number there.

Do you see that there?

A Yes.

Q And your client on this is the California Public Utilities Commission?

A Yes.

Q Is this related to --

Is this a PG&E electric grate case?
A No. It's the San Bruno case.
Q This is the San Bruno case.
And this case concluded?
A Yes.
Q And what was your work in this case?
A I was the expert witness on a records case -- records-related case.
Q And you submitted testimony before FERC?
A No.
Oh, wait. Are we looking at the same --
Q The first item under 2016 to 2018, second item on the page. It shows "FERC Docket No. ER 16-2320-000."
A This looks like an error in my --
Q Is that a mistake?
A I think that's an error. I don't remember a FERC docket on San Bruno.
Q Could you please correct your resume and send us a corrected one at your convenience?
A Okay. Just a minute.
Q The next item down is "SDG&E CPCN For Pipeline Reliability and safety project."
Do you see that?
A Yes.

Q And this identifies your client as UCAN?
A Yes.
Q And you are UCAN's expert witness; is that correct?
A Yes.
Q And this is an ongoing matter?
A Yes. I am -- can I correct --
I am no longer on that case because UCAN, I don't believe, continued in the case. I don't think they're an active participant in it right now; so they paid me my final payment at the end of the first phase.
Q Which was when?
A It would have been in -- I think it actually ended in the end of 2017, if I recall, and I received my final payment in 2018.
Q Okay. And you prepared testimony that was served in that case, correct?
A Yes.
Q All right. The next item down says "2014 - 2016," and the first item is United States versus Pacific Gas & Electric Company, and it indicates it was related to the San Bruno pipeline explosion criminal case; is that correct?
A Yes.

Q And that your client there was the United States Department of Justice; is that correct?
A Yes.
Q Were you --
What was your role in that case?
A I was a consulting expert, and I helped review records and developed discovery.
Q Okay. On any particular scope of issues?
A It was San Bruno. It was just having to do with recordkeeping and technical issues having to do with the pipeline explosion.
Q Okay. What sort of technical issues beyond recordkeeping?
A I reviewed some of the documents having to do with the original installation and maintenance of the pipeline and maybe some inspection records.
Q Thank you.
The next item down identifies an application ATCO Pipelines, "Urban Pipeline Replacement Project, Client: ATCO."
A Uh-huh, yes.
Q Who is ATCO?
A It's a gas utility in Canada. And their offices are in Calgary, I believe.
Q And who was this proceeding before?

A It would have been the equivalent of the Public Utilities Commission only in Alberta.

Q Okay. And this matter is now concluded?

A Well, my contract is concluded on that. I don't know if the case actually closed yet.

Q Okay. And what was your role in that case?

A Okay. Let's see, the pipeline company wanted to get approval to put in a new pipeline that would be installed in a utility corridor around the city and take out of service existing gas lines in the city that were in -- buried in streets that were lined with housing now. And then they wanted -- they were not going to abandon that service.

They were going to de-rate the lines that were providing service within the city to the low pressure service. And so they were asking for my help in convincing the public sector there that it would be a good idea to move the high pressure gas service to a corridor rather than having it run under their homes.

Q And so you were a testifying expert in that case?

A Yes, for The Gas Company.

Q And you served testimony?

A Yes.

Q Okay. Next item down 2011 to present OII, 1.11-02-016 related to the San Bruno explosion. This appears that your role is ongoing.

What is the ongoing work that you're doing?

A No, it's not ongoing. Old. This is done.

Q When did it --

When was it completed?

A 200- -- 2018.

Q Okay. Can you please add that to the list of corrections to your resume?

Jumping down to the bottom of this column, where it says "Playa del Rey Gas Storage Integrity SoCal Edison" --

A Yeah, that's an error. I knew about that.

Q So that should say SoCalGas?

A Yes. I'll correct that.

Q And the description is "Research and evaluation of data related to the operations, maintenance integrity of the Playa del Rey gas storage facility and the proposed sale of surface property."

And your client was the California Public Utilities Commission Division of Ratepayer Advocates; is that correct?

A Yes.

Q Can you please describe a little bit the scope of your work in this matter?

A It was, again, a records review, and there was --

It was probably a reasonableness case where the Gas Company was asking for some money to cover some costs, and as I recall, there may have been a -- yes; so there was a proposed sale of surface property, and they wanted to -- the PUC wanted an assessment of what the sale of the property would involve as far as technical issues related to gas storage.

And there was also an environmental component of this having to do with contamination in Ballona Creek, I think; so I did an interim or a -- you know, an initial assessment for the Public Utilities Commission, and that's the case that I said I think must have settled because I don't recall a final testimony in that case.

Q So as you recall, the case settled prior to testimony?

A I --

Yes, I'm sure I didn't testify in that case.

Q Okay. And do you recall what the specific integrity issues were that you researched and

evaluated?

A There was --

There were some complaints of leakage of natural gas from wells.

Q Okay. So you reviewed those complaints and related records?

A Records, historical records having to do with the storage unit; so there was a few rounds of discovery. I had quite a few gas documents to review from the utility.

And then I did independent research on the groundwater contamination or groundwater issues. Seems like there was a -- somebody who complained or thought that the gas was coming from a storage unit up through the creek.

It was a private resident who was out there counting bubbles in the creek and then filed a complaint. And so I did some research into prior contamination in the creek that could have been causing that.

Q Did you determine whether or not it was being caused by prior contamination in the creek?

A My -- I think --

As I recall my assessment was that it wasn't coming from the gas storage unit.

Q Okay. And in terms of the reference to integrity here, did it -- it didn't relate specifically to SoCalGas well integrity monitoring practices?

A No, not -- excuse me, not integrity monitoring that I can recall.

There was a problem with one or more wells leaking, and I recall one of the wells actually was vented up through a house, which was crazy. Without being able to look back at data, which I don't have anymore, I can't really tell you much more. I'm just telling you what I remember.

Q What you recall. Okay, thank you.

All right. Jumping to the next column, do you see where it states "Application of SoCalGas Company to sell its storage field in Montebello, California, pursuant to Public Utilities Code Section 851"?

A Yes.

Q And then it says "Evaluation of technical data related to the integrity of the Montebello gas storage field."

And your client again there was the Division of Ratepayer Advocates?

A Yes.

Q Were you a testifying expert in this case?
A I filed testimony.
Q You served testimony that you were not able to locate?
A Yes.
Q For purposes of producing it for today's deposition; is that correct?
A Yes.
Q Do you recall whether it was multiple rounds of testimony?
A I expect there was a rebuttal.
Q Okay.
A But I don't remember actually testifying in that case, and I don't -- testifying at the hearings. I don't know if there were hearings and the case --
My part, my evaluation of it was evaluation of storage unit data and leakage; so the gas storage facility was leaking.
Q Okay. Do you recall whether these were operational or abandoned wells?
A What I recall about my part of -- my study of it was not that it was leaking through wells, which it may have been, but that the storage unit itself was leaking. In other words, the geology wasn't containing the gas.

Q So integrity here refers to reservoir integrity, not well integrity?
A That's correct.
Q Okay. Thank you.
You identify a number of other cases on your resume.
Are there any others that relate to gas storage that you see here?
A No.
Q Okay. Ms. Felts, you don't identify any publications on here.
Do you have any publications or articles?
A I have a list somewhere. They're really old. I haven't published anything other than testimonies for a long time.
Q Do any of those publications as far as you recall relate to gas storage?
A No.
Q Okay. Ms. Felts, you've been a testifying expert in a number of disputes including regulatory and civil proceedings, correct?
A Yes.
Q And the civil proceedings include both arbitrations and testimony in court?
A Yes.

Q Have your qualifications as an expert ever been rejected?

A No.

Q Ms. Felts, we identified a number of inaccuracies in this resume.

MR. GRUEN: Objection. To the characterization of "a number of inaccuracies" --

But she can answer.

BY MR. STODDARD:

Q Okay. Ms. Felts, we identified inaccuracies related to items on page 2 of your resume, related to the PG&E FERC docket under 2016 and 2018, identification of the utility in connection with the Playa del Rey storage integrity item, as well as on the first page an incomplete account of the tenure for Invictus Corp.

Based on our discussion there should also be time periods between Dames & Moore and the California Communications Association and potentially between the Department of Defense, McClellan Air Force base and the Department of Toxic Substances Control.

Do you agree?

A Do you want me to add dates to make this more consistent on the front page with the time schedule? In other words, you want me to insert

environmental into the periods?

Q Well, what I would like is a complete accounting of your employment history, and based on our questioning a few moments ago, it sounded like there were interim periods of time where your own company, Invictus Corp or Clemen Energy Services, there were tenures -- there are periods of time for work you did with Invictus that should be listed here between other positions.

A Okay. So when I wrote this, I tried to make it easier by putting litigation consultant 1983 to present to cover that because all of those interim periods I was doing litigation work.

So, I mean, I can rewrite it so that it covers all date periods.

Q If you could clarify and confirm that that's accurate, we would appreciate it. And then make the corrections that we discussed on page 2, and then please confirm whether this is otherwise complete and accurate.

As you sit here today, to your knowledge, is this otherwise a complete and accurate record of your employment history and testifying experience and education?

A Yes. I looked at it, and I don't think

there are any more -- any other errors.

The one I spotted was the Playa del Rey.

I didn't notice that I needed to fix the date on the OII.

And the FERC case, I have to -- I have to look up the number because I just don't remember what that is.

But I'll fix it.

Q Thank you.

Yes, so to confirm, as you just noted, it is three items on page 2 related to the date of the San Bruno investigation, the FERC docket and the Playa del Rey storage field.

A Right.

Q All right. Thank you very much.

Ms. Felts, do you have any operational experience with gas storage fields?

A No.

Q Have you ever worked for a gas storage operator?

A No.

Q Have you ever done engineering work for a gas storage operator?

A No.

Q Do you have any experience related to the

design or configuration of gas storage wells?

A Not directly, but the design and configuration of wells in general is not so different.

Q What experience do you have with the design and configuration of wells generally?

A I have designed and drilled water wells for groundwater monitoring and --

Well, that's all for generally.

Q Okay. And how deep are those wells usually?

A I think the deepest one was actually -- was probably about -- I'm trying to think, about 400 feet shallow wells.

Q And do they have surface casings?

A Yes.

Q And production casings?

A Yes. Depending on what you're drilling through, you have to design it properly so that you isolate the different sands or lenses, clays; so it just depends on what you're drilling through how you design the well.

Q And do they have tubing and packer configuration?

A Generally not necessary; however, I did study drilling in engineering school.

Q Okay. And when you say you studied drilling, you studied gas storage well design and configuration?

A Gas and oil -- oil and gas well drilling.

Q So gas production?

A It would be gas production, yes.

Q Okay. Do you have experience with gas storage well integrity monitoring?

A Not sure what you mean by that.

Q Well, in your testimony you have discussion about well integrity monitoring, correct?

A Say that again.

Q In your testimony you address SoCalGas's well integrity monitoring programs; is that correct?

MR. GRUEN: Just for clarification, when you're going to be asking about testimony, can the witness be directed where in the testimony she is being asked?

MR. STODDARD: Yeah. We can circle back on that.

Q Ms. Felts, what is your understanding of the phrase "well integrity monitoring"?

A I think that is a phrase that either or both SoCalGas and Blade used.

So my understanding of it, it's the

monitoring of the well for -- to make sure that it is not leaking or has not lost wall thickness from corrosion or erosion, and is behaving or -- as intended.

Q Okay. And do you have experience with that process? Have you personally performed well integrity monitoring?

A Well, that's kind of a weird question because well integrity monitoring, although you would have to have field testing to do, you would -- the monitoring itself would be a matter of record assessment.

So data assessment. So you would hire someone to come out and run the tests on the well.

An engineer would look at the results of the test, and I would guess that the integrity monitoring aspect of it would be on the engineering side where you would be evaluating the data that was generated from the well. And the engineer could call for the tests, and my experience would be in reviewing data.

Q What sort of tests are you referring to?

A Well, could be logs of the well, various types.

Could be a -- the use of a tool like a USITs I think they call it now, to determine the wall

thickness of the well.

Could be a temperature survey, a noise survey, they also have some tests for erosion, involves --

Q And do you have experience interpreting casing inspection logs prior to your work in this matter?

A Yes.

Q What was that experience?

A I've looked at casing inspection logs in a number of cases in the past where there were issues of groundwater contamination, and it would be related to an oil production well or a --

I can't remember a gas production well. I think only oil.

Q Do you recall what sorts of casing inspection logs, what the tool was?

A What the tool was?

It was a tool that would monitor -- it would measure the wall thickness of the pipe, the casing. Typically that would be what I would look for.

MR. GRUEN: I'm sorry, I'm just noting just for timing sake, we can keep going, but I'm wondering if you have an idea when you might like to break.

MR. STODDARD: We can take a break after

probably another 10 minutes.

MR. GRUEN: Does that work for you?

Okay.

BY MR. STODDARD:

Q So your interpretation -- I'm sorry, again.

Do you recall the types of tools that were used in that specific instance related to the oil production well?

A I'm going to say that it was similar to the USIT one that SoCalGas is using, but I don't remember the name of the tool.

Q Okay. Any other experience interpreting casing inspection logs?

A Not that I recall just offhand, no.

Q And in interpreting the -- in interpreting the casing inspection log in that instance, do you recall being present at the time that the log was run?

A I have never been present when a log was run on an oil or gas well.

Q Okay. Do you recall communicating with the wire line operator about running the tool that resulted in a log that you interpreted?

A No.

Q Okay. And do you recall approximately when

that was that you interpreted the log related to the oil production well?

A I recall that there was more than one well that I did this on, and I -- I'm going to say it's probably during the 1990s. I don't have a date.

Q Okay. And again, this was based entirely on review of the records?

A Yes.

Q Okay. Do you have any experience with microbially influenced corrosion?

A Yes.

Q Can you please describe your experience?

A It has to do with underground storage tanks that leaked, pipelines that leaked, everything underground exposed to groundwater that I was requested to look at that leaked.

Q So you have experience with it in a number of cases?

A Yes.

Q Do you recall --

Did you perform any testing or analysis related to MIC?

A No.

MR. GRUEN: Just for the record, "MIC" is what is the --

BY MR. STODDARD:

Q I'm sorry, I'm using the phase "MIC" as the acronym for microbially influenced corrosion.

A Yes.

Q Did you perform any testing or analysis related to MIC?

A No.

Q Okay. Finally, Ms. Felts, do you have any experience with well-control or well-kill operations?

A No.

Q Ms. Felts, do you have any experience with --

You're an attorney, correct?

A Yes.

Q Have you ever been involved in a discovery dispute as an attorney?

A No.

Q "No"?

Have you ever been involved in a privilege review?

Do you understand what I mean by "privilege review"?

A Yes.

MR. GRUEN: I'm going to just --

THE WITNESS: Only as a side --

You know, I'm a consultant, there is a privilege review issue, but I'm not the one that gets involved in settling it.

BY MR. STODDARD:

Q So as an attorney, you've never overseen a privilege review?

MR. GRUEN: All right. For the record, I'm just going to note an objection as to relevance in asking her about her role as an attorney here.

But she can answer the question.

MR. STODDARD: The relevance is her testimony asserts violations related to privilege; so I'm asking her about her scope and experience and knowledge related to the subject matter.

THE WITNESS: I'm familiar with the subject matter. It's generally not my responsibility as a technical consultant.

BY MR. STODDARD:

Q Okay. So you've never prepared a privilege log?

A I don't think that's true. I think I probably have prepared one in the past.

Q You've prepared a privilege log as an attorney?

A No, as a technical --

Q You've prepared a privilege log as a technical consultant?

A Yes. I mean, this is a matter of identifying records, and the condition -- the -- whether or not the records are privileged, and if someone asked me to prepare a log, I could prepare the log.

Q So in that context of preparing a log as a technical consultant, you assess the privilege and then you designate the documents accordingly?

A I don't have to usually assess the privilege because it's usually already assessed before I get to it. Someone has already claimed privilege.

Q And then in reviewing the documents you add them to the log and determine that they fall within the scope of the privilege claim?

A Yes. Or I sort -- sort a stack of them and say these are privileged and these are not.

Q Ms. Felts, can you briefly describe your experience with PUC enforcement investigations, prior experience with PUC enforcement investigations?

A I guess I would have to look back at my resume to see who it was that I was working for on the different cases.

Q Let's do that briefly, and I'll make it

quick, Exhibit 1-2.

First on page 2 of Exhibit 1-2, the OII related to San Bruno, was that an enforcement investigation?

A Yes. Yes, it was.

Q Okay. Next down, the Playa del Rey gas storage integrity case at the bottom of this page, was that an enforcement investigation?

A That was Division of Ratepayer Advocates, so I would say no. That was a reasonableness case.

Q And it was related to a sale of property?

A Yes.

Q And then the next item on the next page, the application of Southern California Gas Company to sell the Montebello gas storage field, that also was an application for a sale of an asset, correct?

A Let me see, Montebello.

Q This is on page 2 of your resume in the second column.

A Oh, okay. Okay. That was also for the Division of Ratepayer Advocates, so that would have been a reasonableness review.

Q And it says there it's an application, correct?

A Yes.

Q Okay. Have you ever worked as an attorney in a regulatory investigation?
A No.
MR. STODDARD: All right. Thank you.
We can take a break.
THE VIDEOGRAPHER: Just a moment, please.
This is the end of disk number one, Volume Number 1, of the deposition of Margaret C. Felts on February 5th of the year 2020.
We are off the record at 10:55 a.m.
(Off the record.)
THE VIDEOGRAPHER: This is the beginning of disk number two, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.
We are on the record at 11:13 a.m.
MR. STODDARD: Ms. Felts, actually, I'm going to mark Exhibit 1-3.
(Deposition Exhibit 1-3 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Ms. Felts, do you recognize this document?
A Yes.
Q Is this your contract with the California Public Utilities Commission related to your work in

this matter?

A Yes.

Q Do you see where it says "Start Date October 21, 2019 or upon DGS OLS approval, whichever is later"?

A Yes.

Q Is that the date that this document was mailed to you?

A What date?

Q Is October 21, 2019 the day that you received the contract?

A I don't know.

Q I'll direct you to the bottom of the document where it shows your signature with the date signed of November 5, 2019.

Do you see that?

A Yes.

Q And on the next page it shows a signature from the Department of General Services with a stamp of November 7, 2019.

Do you see that?

A Yes.

Q Okay. Do you recall whether you received this document weeks prior to the date that you signed it?

A I would have received it --

I think I received it a week before this signature date because I signed one and returned it, and then I was notified about five days later that there was an error in the way it was written. Something was omitted so GSA had sent it back and I re-signed it; so this is the second signature of mine.

So there was an iteration in there about a week's turn around. I don't remember the exact date when I received the first draft of it.

Q Okay. Do you recall how it was transmitted to you?

A By email.

Q "By email."

From --

MR. GRUEN: I'm going to note an objection to the extent that calls for attorney-client privilege.

Notwithstanding, I think you can answer that question, if you're able to.

THE WITNESS: So the process here is that the first draft is provided by email for me to review, and then I would return that, possibly with an electronic -- a scanned version with the signature.

When they get the contract ready to be

signed officially, they mail it overnight mail to me, and I wet sign it. And I send it back by, you know, overnight mail.

BY MR. STODDARD:

Q When you say "they," do you mean the California Public Utilities Commission?

A Yes. The contracts officer, yes.

Q Do you recall who the contracts officer was?

A I think her name was Peggy Owens. Peggy Owens.

Q Okay. Did you correspond with SED personnel related to this contract?

A No.

Q Were you contacted by SED personnel prior to executing this contract related to the engagement?

A I was only contacted by the legal office.

Q Okay. So prior to signing this contract, you had not had any -- strike that.

In connection with this engagement, prior to signing this contract you had not had any contact or communications with SED personnel about this matter?

A That's correct.

MR. GRUEN: Can I just clarify it?

By "SED personnel," can you clarify that term?

MR. STODDARD: Thank you. Yes.

Anyone that Ms. Felts is aware is part of the SED department.

Q In other words, staff that would be assigned to SED or counsel working in this matter representing SED, including Darryl Gruen, Amy Yip-Kikugawa or Nicholas Sher.

A Okay. I had communications with Karen Shea and later with Darryl Gruen after the contract was signed.

Q Okay. So you had communications with Karen Shea prior to the contract execution about your engagement in this matter?

A Yes.

Q Okay. Do you recall if those were email communications?

A They would have been email communications. Maybe a phone call.

Q Okay. I don't believe we have those email communications to the degree there are any.

Ms. Felts, I'm going to direct you to Exhibit A of the contract. It's on page -- it begins on page 3. It's the "Scope of Work."

A Okay.

Q Do you see below where it says "Write

opening reply and rebuttal testimony as an expert witness on behalf of the PUC's Safety and Enforcement Division, and based on results of this analysis testify in relation to that testimony at hearings if necessary."

Is that correct?

A Is that at the bottom?

Q I'm sorry, paragraph 5a.

A Okay. I see it.

Q About halfway down that indented paragraph --

A Yes.

Q -- do you see where it refers to you as an expert witness on behalf of the CPUC Safety and Enforcement Division?

A Yes.

Q And then the next sentence which says in preparation for testimony you will provide extensive review of Southern California Gas Company records as necessary to assess compliance with safety requirements?

A Yes.

Q And then turning to the next page of Exhibit A, this is page 4 of the document.

Do you see where it says in paragraph h that

your scope of work includes discuss, support and review legal briefs, motions and other legal and procedural documents as necessary.

A Yes.

Q And in paragraph i where it States, "When necessary, provide and manage subcontractors who may provide necessary technical services and support to SED"?

A Yes.

Q Are you aware of any subcontractors engaged by SED in this matter?

A Do you want to restate that again?

Q Paragraph i states that "When necessary, provide and manage subcontractors who may provide necessary technical services in support to SED."

Do you see that?

A Yes.

Q Are you aware of any subcontractors in this matter?

A Those would be subcontractors to my contract?

Q Or to SED.

A I would not know what SED is doing, but I believe this has to do with if I hired someone to help me as a subcontractor.

Q I'm not asking about your interpretation of the provision so much as asking whether you have been doing work related to providing or managing subcontractors related to technical services in support to SED in this matter.

MR. GRUEN: I'm going to object to that as overly broad, just to the extent it calls for subcontractors which are outside the scope of Ms. Felts' contract.

So one option is to restate that. Or if you want, you can ask her to answer as you've worded it.

MR. STODDARD: I would ask --

Okay, I'll restate in a few different questions.

Q One is have you engaged any subcontractors pursuant to your contract?

A Not yet.

Q Okay. Have you worked with any other subcontractors in this matter engaged by SED?

A No.

Q Do you intend to engage any subcontractors?

MR. GRUEN: I'm going to object to the extent that calls for attorney work product privilege.

And I'm going to instruct the witness not to answer the question.

It also may -- just for the record, that may involve attorney-client privilege as well.

BY MR. STODDARD:

Q Okay. Ms. Felts, what did you do today to prepare for today's deposition?

Did you review any documents?

A I read through the opening testimony.

Q Did you meet with anyone -- I'm not asking you to divulge attorney-client privilege information.

Did you meet with anyone aside from your counsel?

A No.

Q Did you review the exhibits relied upon in your opening testimony?

A I reviewed some of them.

Q Did you review any discovery, data requests and data responses?

A Yes.

Q Do you recall which ones?

A I couldn't give you an exact list, but I looked at some well files.

Q Do you recall which wells the well files related to?

A Well, I assessed 25, 25-A, 25-B, 6, but I'm not sure if it was an SS-6 or another one.

Q Okay. Did you prepare any written materials in preparation for this deposition?
A No.
Q And I apologize for jumping around, but I'm going to refer back to -- it's not exactly necessary, but I'm referring back to your contract which is Exhibit 1-3, and I would just like to confirm do you have any other current contracts with the California Public Utilities Commission?
A No.
Q Do you have any other current contracts with the State of California or any agency or department --
A No.
Q -- thereof?
A No.
Q At the time that you were engaged in your contract, did you understand the scope of your work to be to provide expert testimony in this matter?
A Yes.
Q What did you understand the scope of issues you were to address to be?
A What's described here in this scope of work. That is what I was asked to do.
Q Did you believe that it related to records

review?
A Yes.
Q Did you have prior awareness of the Aliso Canyon incident?
A Yes.
Q Had you reviewed records related to the Aliso Canyon incident prior to your engagement?
A I did not have access to anything other than what was publically available.
Q Did you review what was publically available?
A Yes. I had a file I was collecting stuff in.
Q When did you begin collecting stuff?
A About the time the incident began.
Q Why were you collecting stuff?
A Well, historically I usually get called sooner or later on these things; so I had an interest in it.
Q So you expected to be appearing as an expert witness in this matter before you were engaged by SED?
A Well, it was a possibility. And I'm a consultant.
Q Do you recall the sources that you went to

for those public records?

A Well, I signed up for SoCalGas's regular news, the little news releases that came out, came across, I think on email. I started following a different proceeding having to do with the potential closure of the gas storage unit. And so I --

When I went to the PUC and signed -- you know, electronically signed up for -- to be a party -- not a party, but to receive the information on that case -- and I don't remember the case number, I'm sure you know it --

So I received regular information about that case and kind of followed it. And may or may not have kept records that came through from that.

Q But you -- I mean, you said you "collected" it.

Did you save it in a file on your desktop?

A I would have -- I don't --

I think I probably just saved the emails that came in an email file folder.

Q Okay. And did you review these materials when you were preparing your testimony?

A No. They're not useful for this.

Q Why not?

A Well, I have plenty of data that has come

through discovery on this case to look at without going to some other source right now.

Q Okay. Aside from the scope of work described in your contract, were you engaged in any other capacity by SED to work on this matter?

A No.

Q Has SED utilized you in any other capacity in your work on this matter?

A No.

Q Ms. Felts, were you involved in SED's preliminary investigation related to the Aliso Canyon's incident prior to the initiation of the formal OII?

A No.

MR. STODDARD: I'm going to mark Exhibit 1-4.

(Deposition Exhibit 1-4 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is an email from Mr. Gruen to you and Ms. Shea sent on Friday, November 8th at 9:19 a.m.; is that correct?

A Yes.

MR. GRUEN: If I may, I just noticed, I'm noting that because the document is identified as Public Utilities Code Section 583, that to the extent questions elicit information from Ms. Felts that are protected by PU Code Section 583, we would look to SoCalGas to properly mark that as confidential.

MR. STODDARD: Understood.

Q And Ms. Felts, it appears that this included attachments which were transcripts of examinations under oath conducted by SED; is that correct?

A Yes.

Q Is this the first email that you received from SED in connection with this matter?

A Well, I'd say November 8th would be -- it would have to be the first, or there may have been others that came on that date. I didn't receive anything before this.

Q Earlier you stated you had email communications with Ms. Shea prior to your execution of the contract.

A Well, I think I did about the contract, that was -- she was handling that coordination with the contracts office with Peggy.

MR. STODDARD: Okay. Darryl, while we're on the record, if you'd like us to submit a written request

or follow up with our prior request for all communications, we can do so.

But I prefer to just state it on the record that you confirm the date of the first email communications and produce any additional communications between Ms. Felts and SED personnel or SED counsel.

MR. GRUEN: Yeah. I mean, I think we would like to have -- it's noted for the record, of course.

But we appreciate having something in writing as well if there is an indication that there is something that you have not received.

MR. STODDARD: Okay.

MR. GRUEN: And perhaps just for our understanding if you think that's the case, if you could clarify the dates, just so we understand what dates you're looking for.

MR. STODDARD: We appreciate that. We'll provide that. We don't know the dates of prior emails, which is what we're getting at.

MR. GRUEN: Okay.

BY MR. STODDARD:

Q Since your initial engagement, who have been your primary points of contact for SED?

A Darryl and Karen.

Q "Darryl and Karen"?
Have you also spoken with Mr. Sher, Nicholas Sher, counsel of SED?
A No, not yet.
Q Have you emailed with him?
A No.
Q How about Randy Holter?
A Don't --
I don't know who that is.
Q You don't know who that is.
Matt Epuna?
A No.
Q E-P-U-N-A?
A No.
Q Maria Solas?
A Maria Solas.
No.
Q Lee Palmer?
A No.
Q Bear with me, I'm going to ask some more names.
Amy Yip-Kikugawa?
A I know Amy. I have not communicated with her in years.
Q You know her from prior matters?

A Yes.
Q Is that from San Bruno?
A I think so, yes.
Q How about Ken Bruno?
A No.
Q Jack Mulligan?
A No.
Q Mitch Chafsome?
A No.
Q Have you communicated with anyone from the California Advocates office, the Public Advocates Office, formerly know as the Division of Ratepayer Advocates and several other names?
A Yeah, I was going to say --
Q Have you communicated with anybody from Cal Advocates relating to this matter since you were engaged?
A No.
Q Have you communicated with anyone from Cal Advocates about this matter before you were engaged by SED?
A Ever?
Q Related to the Aliso Canyon incident, to your knowledge.
A No.

Q And since you were engaged have you spoken with Blade, anyone from Blade Energy Partners?
A No.
Q Before you were engaged but following the Aliso Canyon incident, did you have any contact or communication, to your knowledge, with anyone from Blade Energy Partners?
A No.
Q Okay. So based on what you said earlier, and correct me if I'm wrong, it sounds like your only points of communication with SED have been Darryl Gruen and Karen Shea; is that correct?
A Yes.
Q And you communicate via email?
A And phone.
Q And phone; do you text, text message?
A I sent Darryl a first text message this morning to tell him that I got here.
Q Okay. Do you communicate by via mail, hard copy?
A No.
Q "No."
In-person meetings?
A No. I live in Colorado. This is the in-person meeting.

MR. STODDARD: Okay. I'd like to introduce Exhibit 1-5.

(Deposition Exhibit 1-5 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Appears to be an email to me.

Q That is correct. It's an email from Darryl Gruen to you on November 8th, the same day as your first -- well, the same day as the prior email that we discussed --

A Yes.

Q -- related to the EUO transcript.

And this one, the subject line is "Scoping Memo Recordkeeping Language."

At that time was it your understanding that you were being engaged for the purposes of assessing SoCalGas's recordkeeping practices?

A I think that was part of the engagement, yes.

Q Was it your understanding that that was your primary purpose of your engagement in this matter?

MR. GRUEN: Objection. Just use of the word "primary" is vague.

Can you clarify?

MR. STODDARD: Sure.

Q At the time of your initial engagement, and we'll have to be a little bit -- you know, within the first few days of signing the contract, during your initials discussions with SED, was it your understanding that you were being engaged based on your experience with recordkeeping in other utility investigations?

A I think my understanding was that my recordkeeping experience was important to them to be able to look at recordkeeping issues, but also to look at other issues that had arisen through the Blade investigation.

Q Do you recall asking Darryl to send you the specific scope language related to the recordkeeping issue?

A You're asking me if I sent him an --

Q It appears --

A -- email before I got this?

Q Yeah, whether an email or a phone call.

It appears that this email was sent -- there is no context for this document.

A And I don't remember a context to it. I don't remember why he would send me only the

paragraph 4, especially since I think it's in the contract.

Q Do you recall having a phone call about it?

A It's possible. It's possible because he called me right as soon as the contract was signed, and we both received copies of the contract by email; so it's possible that there was some discussion and he sent this as a result of a request or something or maybe clarification. I'm not sure.

Q Okay. Approximately how frequently do you communicate with either Darryl or Karen?

MR. GRUEN: I'm going to just object to the extent that that calls for attorney-client and attorney work product following the publication of the opening testimony.

But to the extent that we're talking about communications prior to the publication of the opening testimony, she can answer.

BY MR. STODDARD:

Q Prior to the publication of the testimony, how frequently did you communicate with either Darryl or Karen? I mean approximate.

A So after the contract was written -- was signed, I -- my communications with Karen diminished to only being able to get access to databases at the

PUC. There was some logistics that was involved in doing that, and I was having difficulty remotely; so that's what was happening there.

And then -- and when the contract was signed, then I heard from Darryl. And I would say we probably communicated daily between then and when the opening testimony was sent. But I don't know exactly. I looked at all of the emails that Darryl copied to you, and as far as I know, that was complete -- a complete set.

Q So daily communications could have been phone and email?

A Possibly, yes.

Q Do you recall multiple times a day?

A Possibly during that period of time because it was a very short lead time. I was trying to look at as much stuff as I could before the testimony was due to be filed.

Q You mentioned having trouble accessing databases at the PUC.

A Yes.

Q Do you recall the specific databases?

A There is a database called Diamond buried somewhere in their system.

Q What kind of database is that?

A It's the one where all of your responses were supposed to be housed.

Q That's a file management system?

A Yes.

Q And you had to be granted access to it because you were remote?

A Well, all of the data in response to data requests was provided to the PUC, I guess, either by email or -- and/or thumb drives. That information was all uploaded to this database at the PUC on their mainframe. And the idea was for me to be able to call in and review records there remotely.

It was obviously too voluminous to print out and send me boxes of paper; So I did receive the responses to DR 16 in paper. I believe Karen sent that to me.

Q Do you recall about when you successfully gained access to the PUC's database?

And, again, I'm not asking for a specific date here; it's more relative to your engagement or your opening testimony.

A I would say sometime right around the time the testimony was filed.

Q Before? After?

A I don't know without looking back at the

dates on the -- on the emails, but I would say maybe a couple of days before.

Q Okay. And before you gained access to the Diamond database, any documents that you would have been -- that SED would have transmitted to you would have been via email?

A No. I don't think I got any data responses by email before then.

I had the Blade reports, which was a lot of reading and review. And so I had -- I had the transcripts that were emailed to me that you just saw in this last email.

And then I had the paper copies of DR 16 to look at, which included a set of the daily reports for Boots & Coots drilling. And I think that's primarily what I had to look at initially, which --

And so a full set of the Blade reports included all of the supplemental reports; so it was a complete set of the volumes of that.

Q And did the PUC -- or SED, I'm sorry.

Did SED share anything with you via FTP?

A Not at that time. I didn't have an FTP access until probably at least three weeks after my contract started, and then I was able to FTP large files.

Q The Blade report, where did you obtain that on the Aliso Canyon's web page?

A No, I couldn't download it, but I had tried actually when they started to talk about the contract, and the only thing I could get was the main report; so the rest of it was mailed to me in hard copy. Karen sent it to me.

Q Okay. Was anything else mailed to you in hard copy?

A The responses to DR 16.

Q Okay. Do you recall the approximate date that you received the Blade report in the mail?

A I think it was mailed overnight mail right after the contract was signed.

Q And you reviewed it after you received it?

A Yes.

Q Do you recall how long it took you?

A There are days when I'm still reading on it.

Q Did you review other preliminary investigation -- preliminary SED investigation records aside from the documents that we've just discussed --

A No.

Q -- prior to preparation of your opening testimony?

"No"?

So the records produced by SoCalGas would have been limited to those that were shared with you by SED between the contract date and the date of your opening testimony?

A I -- I had to have had access to the Diamond database at least a couple of days before because I spent at least a day looking through the SS-25 well file. And it was the first file that was provided to -- in response to a data request. I think it must have been in response to the Data Request 1.

It was a file of individual -- each page was an individual PDF. That is the well file that I reviewed before the opening testimony was filed.

Q Do you recall reviewing any other records in the Diamond database aside from the well file prior to your -- to service of your opening testimony?

A I believe I read there was -- there were copies of the Data Request 1 and a Data Request 1 that was SED and D-O-G -- DOGGR, and Data Request 2; so I think I only reviewed the response attachments, the data, for DR-1.

Q Thank you.

Did you review the Public Utilities Code prior to preparing your opening testimony or prior to

serving your opening testimony?

A I reviewed Section -- is it 451? The safety section, whichever that one is.

Q That's it?

A That's it.

Q Did you review the Commission's Rules of Practice and Procedure?

A No.

Q Did you review any internal SED legal research or analysis?

A No.

Q Since you've been engaged by SED, we talked about the scope of work a little bit earlier in your contract.

Since you've been engaged by SED, have you assisted with preparation of any pleadings?

A No.

Q Data requests?

A Yes.

Q Data responses?

A Yes.

Q Did you review any draft SED reports related to findings of their preliminary investigation?

A What would that be?

Q Any documents that include findings,

summaries of evidence, alleged violations.

A Other than the draft filing, the draft opening testimony?

Q Other than the draft opening testimony.

A No.

Q Earlier we were talking about the Blade report. I'm going to briefly check to just see if you've had any contact with any of the individuals.

Will you allow me to just name the names?

If she doesn't know them, she doesn't know them. If she does, she does. I'm not going to enter this as an exhibit right now.

MR. GRUEN: No objection.

BY MR. STODDARD:

Q Ms. Felts, do you know Ravi Krishnamurthy?

A No.

Q Have you ever spoken to Mr. Krishnamurthy?

A No.

Q Have you ever had email contact with Mr. Krishnamurthy?

A No.

Q How about Nigel Alvares?

A No.

Q Greg Asher?

A No.

Q William Bacon?
A No.
Q Miodrag Bogdanovic?
A No.
Q Ismail Ceyhan?
A No.
Q Ming Gao?
A No.
Q Bill Whitney?
A No.
Q Shree Krishna?
A No.
Q Are you familiar with Ecolise, an entity named Ecolise?
A No.
MR. GRUEN: I'm sorry, can you clarify, is that a person?
MR. STODDARD: No, that's a company. Ecolise.
MR. GRUEN: Okay.
BY MR. STODDARD:
Q Liz Summer, do you know her?
A No.
Q How about Jerry Shursen?
A No.
Q Or GSM Oil Field Services?

A No.
MR. STODDARD: We're going to introduce Exhibit 1-6.
(Deposition Exhibit 1-6 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Ms. Felts, have you seen this document before?
MR. GRUEN: I'm sorry, can we just give the witness an opportunity to review this?
MR. STODDARD: Yes.
THE WITNESS: I don't think I've ever seen this.
BY MR. STODDARD:
Q Okay. It's an email from Bob Pilko to Randy Holter and Bill Whitney with Ravi Krishnamurthy, Cyndy Reed and PV Suryanarayana copied, and it's from January 28, 2016.
Do you know, have you --
Do you know Bob Pilko?
A No.
Q Have you ever had contact with Bob Pilko?
A No.
Q Do you see below where it states --
It's an email from Randy Holter and says

"Hello Bob, I want to introduce myself for as the Lead Investigation for the CPUC on the Aliso Canyon Storage Facility SS-25 Well Leak."

A Yes.

Q Were you aware that Randy Holter was the lead investigator for SED on the matter?

A No.

MR. GRUEN: I'm going to just object to that as the characterization is vague as to time; so just the question was asked in the present tense.

BY MR. STODDARD:

Q Are you aware that Mr. Randy Holter at any period of time is or was the lead investigator in the Aliso Canyon matter?

A I don't really know anything about the case prior to me coming on it.

Q And you earlier said you haven't had any contact with Mr. Holter, correct?

A I don't know who that is. No.

Q Okay. Are you aware of any other individual for SED being identified as the lead investigator or having the role of lead investigator at this time?

A Right now?

Q Yeah.

A I don't know who might have that

designation.

MR. STODDARD: Okay. I'm going to introduce Exhibit 1-7.

(Deposition Exhibit 1-7 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is your --

This is the opening testimony of SED in the Aliso Canyon investigation proceeding, correct?

A Yes.

Q And if you look at the top left corner it identifies the docket number, the commissioner, the administrative law judge.

It does not identify you as the witness; is that correct?

A Right.

Q And there is no witness identified; is that correct?

A Looks like that's correct.

Q Do you have any changes to your testimony at this time?

A No.

Q You said you reviewed this in preparation for today's deposition, correct?
A I reviewed part of it.
Q Which part?
A Let's see if I can find it.
Starting at page 51 I read that last night.
Q Okay. So you started reviewing the testimony immediately after the sections that deal with the Blade report; is that correct?
A Yes.
Q Why didn't you review the sections that deal with the Blade report?
A I felt like I could answer questions about that so I didn't need to refresh my memory.
Q Okay. Did you write this?
A No.
Q Who did?
A Well, let me take that back.
I wrote part of it. I wrote the recordkeeping section. And the rest of it was already drafted when I arrived on the scene.
Q Do you know who wrote it?
A No.
Q Who did you receive it from?
A Darryl.

Q Did you ask who wrote it?
A No.
Q So you didn't want to speak with the person who prepared the testimony to ask them questions about why they included certain information?
A I just read it and felt like I understood what they were writing about. I didn't feel it was necessary to track down authors.
Q But you are sponsoring it as your own testimony, correct?
A I was asked to sponsor it. I read it and I said that I could sponsor it, and so I am.
Q The entirety of the testimony?
A Yes.
Q Okay. It includes --
I mean, it's approximately 80 pages, is that correct, 82 pages?
A Yes.
Q And it includes close to 500 footnotes?
A Yes.
Q Did you review and confirm each of the footnotes?
A I read the footnotes. I did not verify them all. Some of them I went to the source, others I did not.

Q So for everything that is cited in here, you reviewed the document that it was cited to?

A I'd have to look at every footnote to answer that question. Is that what you're asking me?

Q Well, I'm asking whether you were approached to getting yourself comfortable in sponsoring this report included reviewing all of the evidence -- alleged evidence that is relied upon in the document.

A There may be a couple of footnotes that I didn't verify, but generally everything that is tied to the Blade report I verified. If there is something else in here that didn't look like it was necessary for me to verify it, I didn't. There may --

I think there are supporting documents that --

Q The exhibits?

A -- that I reviewed.

Yes, the exhibits that went along with it, which would be, say, in the section that I was reviewing last night, there were some letters and exhibits that were provided, and I did read those.

Q Did you review all of the exhibits?

A Yes.

Q Last night or prior to --

A No, prior to the testimony right now.
Q Prior to the service of testimony?
A Yes.
Q Did you review those exhibits -- strike that.
Did you --
You didn't speak to Mr. Mansdorfer, correct?
A No, but there is an EUO of Mansdorfer that I read.
Q So you reviewed all of the EUOs?
A I didn't review them all. I think there are still two or three that I have not read completely, and one of those is Brett Lane, and I don't know, maybe Volume 2 of Brett Lane, and I'm not sure about -- but I'm pretty sure there is at least two others that I haven't read.
Q Do you recall if you've reviewed the Boots & Coots witness EUOs?
A Yes, I did.
Q In the process of preparing or getting yourself comfortable with sponsoring the testimony prepared by others, did you keep any handwritten notes?
A No. I just read -- it was very fast paced review because I didn't have much time.

So I was working primarily with the Blade report and with this document to make sure that they were properly drawing -- drawing conclusions out of the Blade report to this report and that things weren't being misstated.

Q So you worked to confirm that things weren't being misstated relative to the Blade report?

A Right, yes.

Q You weren't concerned with whether or not the Blade report itself was consistent with the evidence or the facts that have been presented in other records in the proceeding?

A So I had very little time and very difficult -- and a lot of difficulty getting access to data that had been provided by SoCalGas. In fact, a lot of the files that I was trying to open, and to this day I can't open, they say that the files were corrupted; so I didn't have access to all of the response data that SoCalGas said they provided.

And the best I can do is with my technical knowledge in reviewing the Blade report and just validating in my own mind that what they were doing made sense, and I did review the daily reports with Boots & Coots and compared that to what Blade said had happened. And I just checked to make sure that

what was drafted in the opening testimony relative to the Blade report accurately reflected what Blade said.

Q And you were comfortable with that process?

A Well, it was the best I could do in the amount of time I had available. If I had had more time, I would have looked at all of the data and written my own report. But I didn't have that luxury.

Q When you were initially engaged, did you have an understanding of the timeline?

A I knew when the opening testimony was due. I knew they were hoping to get some testimony from me, but as the date drew closer, it was -- it was at least possible in my mind that I wouldn't be able to produce testimony in that period of time.

Q In part because of the technical difficulties with accessing records?

A And the fact that the contract wasn't signed; so, you know, the date when it was due wasn't changing, and I wasn't engaged yet. So there is only so much you can do in a couple of weeks' time.

Q So did you begin work prior to --

Did you begin substantive work in this case prior to execution of the contract?

A No.
Q So your concern with the delay in the execution of the contract was you understood that you had testimony due on a date certain --
A Right.
Q -- but that you weren't going to start looking at records until after the contract was done?
A Right.
Q So you wouldn't start substantive work or communicate with SED until after the contract was done?
A Exactly.
Q And did you understand at the time that you were engaged that there was already draft testimony that had been prepared?
A I think Darryl told me that they were working on a draft when he called me and the contract was signed; so before that, I didn't know that they were drafting anything.
Q And did he tell you or describe the scope of violations or issues that your testimony would be addressing?
And I don't mean the scope of work contractually. I mean the scope of issues that is in your testimony substantively.

A I'm sure we talked about that.
Q Okay. You indicated you didn't keep any notes, but in reviewing documents, you said mostly you read.
Did you mark up documents, underline, keep margin notes?
A Excuse me. Just a second.
I typically don't mark documents. I rarely highlight anymore. And sometimes I use sticky notes.
THE VIDEOGRAPHER: You've lost your microphone.
THE WITNESS: I'm sorry.
THE VIDEOGRAPHER: It's just off the clip there.
THE WITNESS: Sometimes I use sticky notes to mark pages.
BY MR. STODDARD:
Q In this case you used sticky notes to mark pages?
A Like a tab, you know?
Q Right.
A Yes.
Q And do you recall highlighting any documents in this?
A I don't believe there is any highlights in any documents.
Q Okay. And did you collect records that you

had marked with highlights or sticky notes and provide them to SED in connection with a request for work papers?

A Well, there weren't any highlights, and so a sticky note thing, I would just tab a page so I would go back to it, and I typically reuse those tabs so there wouldn't be any way to recover that as something to send to you.

Q What do you mean "reuse"?

You put them on the document and then you take them off the document?

A Yeah, I reuse them.

So I mark documents -- I mark pages that I want to go back and look at. Once I go back and look at it, I pull it off, put it in my sticky note pad and reuse it somewhere else.

Q So does your copy of the Blade report that is sitting at your home today have sticky notes on it?

A No. There is no sticky notes in my Blade report right now.

Q Do you think any of the documents that you have at your home in hard copy related to this investigation presently have sticky notes on them?

A They might presently, but they would be

documents that I didn't have prior to the filing of the initial testimony.

Q Okay. We can take a break after -- just one more question and then we can break for lunch.

The sticky notes that you use, are they like this kind, Post-it notes?

A Yes.

Q Well, I wasn't sure if it was like that or a blue kind, like a flag.

A No, I don't have the little blue kinds. I only have yellow ones.

Q For the record, Ms. Felts indicated that she uses the little Post-it notes.

Do you write on them?

A No, not often. I mean, if I wrote something on it, it would be like a -- something that says "Read this again."

Q Do you recall writing anything on any sticky notes in this case prior to the service of your opening testimony?

A No, I don't even think I used sticky notes prior to the opening testimony.

Q Since service of the opening testimony?

A It's possible there is something written on some note somewhere.

Q Okay. And aside from that, you haven't kept any other notes, handwritten, electronic --

A You're asking me --

Q -- or otherwise?

A -- prior to the opening testimony being filed?

Q Yes.

A You have everything I had, which is whatever Darryl sent you.

MR. STODDARD: Okay. Let's take a break for lunch. Come back at, let's say, 1:15. Let's make it 1:10 and we'll get started at 1:15.

MR. GRUEN: That sounds reasonable.

THE VIDEOGRAPHER: This is the end of disk number two, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are off the record at 12:15 p.m.

(Lunch recess.)

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon Storage Facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility. (U904G).	I.19-06-016 (Filed 6-27-19)

DEPOSITION OF MARGARET C. FELTS
Los Angeles, California
Wednesday, February 5, 2020
AFTERNOON SESSION

Reported by:
LINDA RYAN
CSR No. 9915
JOB No. 311652

Los Angeles, California

Wednesday, February 5, 2020

1:24 p.m. - 8:39 p.m.

THE VIDEOGRAPHER: Here begins disk number three, Volume Number 1, of the deposition of Margaret Felts on February the 5th of the year 2020.

We are on the record at 1:24 p.m.

MR. GRUEN: I'm terribly sorry. Could we go off the record for just a moment, would that be okay?

MR. STODDARD: Yes.

THE VIDEOGRAPHER: Just a moment, please.

We are off the record at 1:24 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 1:24 p.m.

MR. GRUEN: While we were off the record we just had clarified that during the lunch break, Ms. Felts had refreshed her recollection as to her role regarding the item on her resume, entitled the "PG&E General Rate Case FERC Docket No. ER 16-2320-000," and she is prepared to make a statement for the record as to her role updating the information she provided this morning.

BY MR. STODDARD:

Q Okay. And for the sake of clarity, this relates to Exhibit 1-2; is that correct?
A Yes.
Q Go ahead.
A Okay. So on that case the only thing I did was help with some discovery and reviewed the responses to that discovery, and I believe I sat in on one interview.
Q And by "interview," do you mean deposition?
A It was actually something informal. It was not a deposition.
Q And you were retained as an consulting expert?
A Yes.
Q In what capacity? What was the scope of your work?
A It had to do with electric utility issues. And, honestly, without looking back at the file, I couldn't tell you exactly what it was that we were looking at.
I remember that I was doing discovery. I did not file testimony, did not write anything.
Q And your client was the California Public Utilities Commission?
A Yes.

Q And do you recall what the case concerned?
A So it was a rate case, so there must have been some subset of the rate case that they needed expertise on that I could provide; so I didn't -- I don't think I billed very much on that case.
Q What discovery questions do you recall preparing?
A None. I would have to look at a file to see.
Q Do you remember the general subject matter?
A No. I don't really remember too much about it.
Q Okay. But it didn't relate to natural gas storage facilities?
A It had nothing to do with natural gas.
Q Okay. And otherwise that entry is accurate on your resume?
A Yes.
Q Except for the spelling of legal office.
A Okay, I'll correct that.
Q All right. Thank you for that.
So I have another couple of questions I'd like to circle back on that relate to a few other topics that we covered prior to lunch.
And the first is we talked a little bit

about your work since you were engaged by SED prior to service of your opening testimony and who you spoke with or have spoken with related to your work preparing testimony for the Aliso Canyon matter.

You indicated you hadn't spoken with anybody at Blade, correct?

A That's correct.

Q And you indicated that you hadn't spoken with any other subcontractors, you know, working for SED or for you prior to service of your opening testimony, correct?

A That's correct.

Q Okay. Have you spoken with any other technical experts related to your work on this matter --

A No.

Q -- whether engaged by the Commission or not?

A No.

Q Have you spoken with anybody at SoCalGas about your work on this matter?

A No.

Q Have you spoken with anybody at SoCalGas about the Aliso Canyon incident generally?

A No.

Q Have you spoken with anybody at DOGGR about

the Aliso Canyon incident?

A No.

Q Have you spoken with anybody at the California Energy Commission about this incident?

A No.

Q The Governor's office?

A No.

Q State Legislature?

A No.

Q Okay. Thank you.

And to clarify, that was the California State Legislature. I know you're a resident of Colorado.

A I haven't spoken with anybody in either state.

Q Is your answer the same?

A Yes.

Q Have you spoken with anybody who is employed by the County of Los Angeles?

A No.

Q The Department of Public Health in Los Angeles?

A No.

Q Any federal authorities or public officials?

A No.

Q Okay. Any other government officials in any jurisdiction or any agency about the Aliso Canyon matter that you're aware of?

A No. I haven't actually talked to anyone about this case.

Q But --

What about prior to your engagement in this matter by SED, you know, understanding that it goes back a little ways, do you recall any significant discussions that may be relevant to your testimony?

A Nothing relevant to my testimony. At some point maybe a year ago I might have spoken with Darryl Gruen about the case coming up or that it may be it was already in the works. I'm not sure. But we were working on San Bruno; so I probably mentioned the case to him at some point in time that I would be interested in working on it.

Q Okay. So you reached out to Darryl to indicate an interest in helping out on the case?

A Yes. It was a long time before they actually called me and asked if I would do it, work on it.

Q Do you recall the contents of that communication --

A No.

Q -- what you said?
A I probably just said "Gee, Darryl, I'm a petroleum engineer in a former life, and I would be really interested in working on this Aliso case."
Q And how did Darryl respond?
A He probably told me they were handling it internally because I didn't hear back about it; so just, you know, a consultant reach out.
MR. STODDARD: Thank you.
I'd like to introduce Exhibit 1-8.
(Deposition Exhibit 1-8 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Ms. Felts, do you recognize this document?
A Yes.
Q This is a data request from Southern California Gas company to SED. And if you can refer to page 3, please, there is a single request.
Do you see that?
A Oh, right, yes.
Q It says "Identify the sponsoring witness(es) for SED's Opening Testimony."
A Yes.
Q Did you help prepare the response to this

question?

A No.

Q Did you review the response to this question?

A Not until after it was filed.

MR. MOSHFEGH: That's a different one.

MR. STODDARD: I'd like to introduce Exhibit 1-9.

(Deposition Exhibit 1-9 was marked for identification and is attached hereto.)

MR. STODDARD: I apologize, Ms. Felts. I'm going to restate one of my last questions because I realized you didn't have this document in front of you.

Q Just to confirm, my prior question is related to the data request from SoCalGas, which identified the question on page 3.

And also if you can please reference on page 2 of the SoCalGas data request paragraph 3 identifies a response deadline by close of business on December 6, 2019.

Do you see that? Paragraph 3 on page 2. It's the first at the top of the page.

A Okay, yes.

Q It has the deadline.
A I see that.
Q And it states the deadline is December 6, 2019, which was a few weeks after your testimony was served, correct?
A Yes.
Q Now, please refer to what we've marked Exhibit 1-9.
Do you recognize this document?
A Yes.
Q Did you help prepare this response?
A No.
Q Did you review this response?
A Not until after it was filed.
Q And this states that the sponsoring witness for SED's opening testimony is Ms. Margaret Felts; is that correct?
A Yes.
Q Did SED consult you about this before they served it?
A Well, they --
Q They filed it?
A They asked me to sponsor the testimony before it was filed, if that's what you're asking. The data response itself was handled, I assume, by

Darryl Gruen.

Q So why wasn't your name on the opening testimony that was served by SED?

A Well, since I didn't prepare the cover page, I can't answer that. It was filed by the PUC. I assume that might have been an oversight because I had agreed to sponsor it before it was filed.

Q Did you discuss the fact that your name wasn't on it?

A I didn't know until --

Q After the fact.

A I actually didn't know -- notice it until you just put it in front of me and said that it was empty, that it was blank. I don't even know if I ever had a printed copy of the cover. I might only have an email copy of the document.

Q So there was no discussion about whether they could identify you as their witness on the document prior to service?

A Well, there was discussion prior to service, and I agreed that I would sponsor it.

MR. STODDARD: Okay. I'm going to introduce Exhibit 1-9.

THE WITNESS: That's what I have in front of me.

MR. STODDARD: I apologize, I have to get these

Post-its off.

Exhibit 1-10.

(Deposition Exhibit 1-10 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document?

A Yes, I've seen it before.

Q If you'll turn to page 3.

A Okay.

Q You'll see the first data request at the bottom is "Identify the date on which SED retained Margaret Felts in connection with the Proceeding."

Do you see that?

A Yes.

Q If you'll turn to page 4 on the back, question 2 is "Identify the date on which Margaret Felts agreed to adopt the entirety of SED's Opening Testimony."

Do you see that?

A Yes.

Q And Commission 3 requests your statement of qualifications.

Do you see that?

A Yes.

MR. STODDARD: I'm going to mark and introduce Exhibit 1-11.

(Deposition Exhibit 1-11 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document?

A Yes.

Q Did you prepare this data response?

A No.

Q For purposes of the record, this is SED's data response to SoCalGas's data request for Exhibit 1-10.

And you see question 1, 2 and 3 from the prior data request restated there?

A Yes.

Q And SED's response was that SED contracted with Ms. Felts in connection with this proceeding on November 7, 2019, correct?

A That's correct.

Q And it states in response to question 2 that you agreed to adopt the entirety of SED's opening testimony on approximately November 17, 2019; is that correct?

A I think that's correct.

Q Which was approximately five days prior to service of your testimony, correct?
A Yes.
MR. STODDARD: I'd like to introduce Exhibit 1-12.
(Deposition Exhibit 1-12 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q What is it?
A A report from the San Bruno case. It was the first one that was filed in March 12, 2012.
Q So this was your opening testimony in the San Bruno case?
A Yes.
Q In which PG&E was a defendant?
A Yes.
Q And it states on the cover document clearly that it is the report and testimony of Margaret Felts, correct?
A Yes.
Q Did you write this testimony?
A Yes.

Q Do you recall approximately when you were engaged by CPSD for purposes of preparing this testimony?

A Let me look at my resume. It's probably on there.

2011. I don't have the day, the day and month.

Looks like February 2011. It would have been sometime shortly after that.

Q February 2011?

A Sometime shortly after that because that's the date of the OII.

Q Okay. So approximately a year before your testimony was served?

A Yes.

Q And do you recall who your point of contact was at SED, then I think CPSD?

A Initially it was Bob Cagen.

Q "Bob Cagen."

And do you recall reviewing SED's investigation records for the purposes of preparing your testimony?

A In this case?

Q Uh-huh.

A No.

Q "No."

What generally do you recall in terms of your process related to preparing this testimony in this case? What did you review generally?

A Well, PG&E data that was submitted to the Commission.

Q So by "data" you mean records and documents?

A Yes.

Q Did you also review the NTSB report?

A Yes, I did.

Q Did you review an SED report?

A An SED report?

Q A report or document from SED related to their findings in this matter.

A I don't remember an SED report. There could have been one. There was a lot of -- a lot of records that I looked at.

Q And do you recall who your point of contact was at SED after Bob Cagen?

A Darryl Gruen.

Q And in this case did either Bob or Darryl hand you a prepared draft of this testimony when you --

A Of this testimony?

Q Yes.

A No. I actually prepared the entire thing.
Q So you prepared the entirety of this?
A Yes.
Q Based on your review of PG&E's records and data?
A Yes.
Q And based on the NTSB report?
A I probably referred to the NTSB report somewhere.
MR. STODDARD: Okay. Thank you.
1-13.
MR. MOSHFEGH: Yes, 13.
MR. STODDARD: I'm going to introduce and mark Exhibit 1-13.
(Deposition Exhibit 1-13 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q What is it?
A This is the testimony I filed on behalf of UCAN in the SCG and SDG&E's Line 1600 Replacement case.
Q And if you'll turn to the Table of Contents,

which is on page 2, this provides kind of -- the Table of Contents for your testimony which includes prudent management of gas applied for safe operations demands, prudent engineering and various other subject matter areas that you cover in your subsequent testimony, correct?

MR. GRUEN: I'm just going to note an objection for the record.

To the extent this goes to the substance of the testimony, and it sounds like these questions are beginning to touch on substance, noting the objection at the outset that these are questions regarding a currently open proceeding to which SoCalGas and SDG&E are a party before the Commission.

And so the objection is that the -- any information that is elicited from Ms. Felts on this point, that it would be inappropriate to include that information in the record of that proceeding. And our understanding is that the information elicited is only for purposes for the notice of deposition in the Aliso Canyon proceeding.

And I would further notice that Ms. Felts -- that the attorney who is responsible representing UCAN, which -- and this testimony was prepared for UCAN -- UCAN's attorney is not present at the

deposition today.

MR. STODDARD: Your objection is noted again.

Q Ms. Felts, did you prepare this testimony?

A Yes.

Q Who was your point of contact at UCAN?

A Don --

I forget his last name.

Q Did anybody at UCAN hand you a draft of this testimony when you agreed to be their consultant and ask you to sponsor this?

A No.

MR. STODDARD: Thank you.

I'm going to introduce Exhibit 1-14.

(Deposition Exhibit 1-14 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q It's an email from Darryl Gruen to Margaret Felts sent on Sunday, November 17, 2019, copied on Karen Shea with the subject line "Re: Status of testimony Attorney Work Product - Confidential."

Was it your understanding that your work was protected by attorney-client privilege or attorney

work product privilege?

MR. GRUEN: I'm going to just note an objection that that doesn't characterize the complete document in that there is indeed a response from Darryl Gruen to Margaret Felts, but that the remainder of that email is, in fact, an email from Margaret Felts dated November 17, 2019 at 9:25 p.m.

MR. STODDARD: Okay.

Q Again, just to confirm, however, it's two emails; the top email is from Darryl Gruen sent on November 17th to you with a cc on Karen Shea. And the subject line is "Re: Status of Testimony Attorney Work Product - Confidential."

A Yes.

Q "Yes."

Was it your understanding that your work was protected by privilege during this period?

A No. I was advised early on when I -- when I received the contract that my communications would probably not be confidential and could be disclosed.

Q Did you put that subject line in there?

A I don't know if I put it on there or if Darryl put it on there.

Q Okay. Who advised you regarding your statement a moment ago that whatever you did in this

proceeding was likely not privileged and therefore could be disclosed?

A Darryl Gruen.

Q In your email below which was sent on November 17, 2019 at 9:25, you wrote "Over the weekend, I read all 1597 pages of the Well File provided by PG&E to SED."

I assume in that instance you meant SoCalGas?

A Right. On the brain.

Q "I did this because I figured it would be the best representation of the condition of SoCalGas's files," correct?

A Yes.

Q And then you state "The file actually included records for Wells SS-25, SS-25A and SS-25B," correct?

A Yes.

Q Did you access this file through the Diamond database we were discussing earlier?

A Yes.

Q So you were, in fact, reviewing an electronic production of records from SoCalGas's well file provided in response to a data request, not a physical well file, correct?

A Correct.
Q And you reviewed all 1,597 pages in the weekend as well as the data responses we discussed earlier and the Blade report prior to your submission of your testimony on November 22nd?
A Yes.
Q Did you also look at the data responses, the responses to Data Request 16, that same weekend?
A Yes.
Q Did you look at the underlying records produced in response to Data Request 16, a document production?
A I had a hard copy, I think, of the whole response. But I haven't verified that against the electronic response.
Q Do you recall receiving a privilege log in connection with the Data Request 16 response?
MR. GRUEN: I'm going to --
Just a clarification. If this is asking about testimony, if that's where this is going, if the witness could be referred to testimony, the testimony where the questions are going to be directed, I'll just note that.
MR. STODDARD: I'll refer to the email.
Q The last sentence of the email states

"I also looked at the responses to Data Request 16. These are records related to the well-kill efforts, so post October 2015."

And in connection with that, I am wondering what you reviewed and what you had related to Data Request 16, including --

Well, my last question, which is do you recall receiving a privilege log related to Data Request 16 and did you review it at that time?

A I don't really remember that there was a privilege log, but it could be bound in the front of that document.

So what I received was a bound document that was about this thick that was all DR 16. And it was Bates paged through it. I just don't -- I wouldn't spend any time looking at a privilege log if there was one at the front of it. It could have been there.

And the document contained a lot of copies of emails, a lot of duplicates of emails, and Boots & Coots daily records, not particularly well organized, and some -- I think some communications from Halliburton, maybe some technical records from them, like a proposal or something.

Q Okay. Do you recall there being

supplemental responses to Data Request 16 included in the material you reviewed?

A I don't think anything was labeled that way. I think it was just the actual documents that were bound in that volume.

Q Okay. In response to my question regarding whether you reviewed a privilege log associated with SED 16, you stated that "I just don't" -- "I wouldn't spend any time looking at a privilege log if there was one at the front of it."

Since then, have you reviewed a privilege log associated with SED 16?

A I may have looked at it in -- on -- in the database. Have not really given it any thought.

Q Okay. Have you reviewed any other version of the well file aside from the version that you describe in this email?

A I think I've seen at least two other versions in the response sets.

Q In SED's Diamond database?

A Yes.

Q Have you ever reviewed the well files in person?

A No.

Q Have you ever reviewed Blade's copy of the

well file?

A Not yet.

Q Is it your understanding that SED is in possession of Blade's version of the well file?

A I believe they have it. I haven't seen it yet.

MR. STODDARD: I'm going to note for purposes of the record that SED produced this document to us, but we didn't get a separate production of the initial email.

MR. GRUEN: I'm sorry, I can't --

MR. STODDARD: We got the response.

MR. GRUEN: I'm not clear when you say "this document," I'm not clear what --

MR. STODDARD: Referencing Exhibit 1-14.

MR. GRUEN: Okay.

MR. STODDARD: We received --

You produced this document to us, but if you'll see, as you pointed out, this is two separate emails.

MR. GRUEN: Right.

MR. STODDARD: And the bottom email, which includes -- which is the email from Margaret to SED, we don't have an independent version of that; so we aren't able to tell --

One of the reasons I asked about who added the "subject" line is we can't tell who made that designation based on this document and whether it was included with hers, because hers doesn't include the data at the top, including the subject line or any other data.

MR. GRUEN: Okay.

So for the record, the document does note "On November 17, 2019 at 9:25 p.m. Margaret Felts," and it has her email address, "wrote:" And then it provides the text that was being referred to and asked about.

MR. STODDARD: That's correct.

MR. GRUEN: I'm noting that just for the record.

And I think you're asking for us to produce that, just for the record.

MR. STODDARD: Yes.

MR. GRUEN: I think you're asking us to produce that email, the original email; am I tracking correctly?

MR. STODDARD: That's correct.

MR. GRUEN: Okay. We can do that.

Just for the record as well -- strike that.

We'll go ahead with that. That's fine. Thank you.

MR. STODDARD: All right. I'd like to mark Exhibit 1-15.

(Deposition Exhibit 1-15 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q And this is an email from you to Mr. Gruen dated November 18th. It's Monday, the day after the email that was marked Exhibit 1-14. And the subject line is "Confidential Attorney Work Product."

Do you see that?

A Yes.

Q Does this --

Did you add the "Confidential Attorney Work Product" subject line in this email?

A I could have added it, or I could have just replied to another email and added the text below. Sometimes I do that. I just pick out the latest email that Darryl sent and just reply, and use the same heading --

Q So you might --

A -- and send it.

Q So you might have deleted the other email in

this document?
A Yes.
Q Did you collect this document and provide this to Darryl for purposes of production to SoCalGas?
A I think Darryl probably sent it from his database, his email. I mean, produced it to you.
Q Okay. So do you commonly delete emails when you're replying in chains? Is that a typical practice or occasional?
A If I'm just looking for the latest email address for a person, that's what I do, I just pick one off of the most recent email and reply to it.
Q So in other words, if his email to you was on a different issue, you might --
A Yes.
Q -- delete that but use it for purposes of responding to him --
A Yes, that's correct.
Q -- or sending --
Ms. Felts, do you see where it says "Attachments: 2019 Draft Testimony"?
Do you see that?
A Yes.
Q You were sending Darryl a draft of your

testimony, correct?
A Yes.
Q Do you recall if this was the first draft that you sent him?
A I expect this was probably the first draft, and it was a draft of the part of the testimony related to records or recordkeeping.
MR. STODDARD: Okay. We're going to introduce Exhibit 1-16.
(Deposition Exhibit 1-16 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q Is this the document that you previously referenced as your draft testimony regarding recordkeeping issues?
A I expect that's --
This is it, yes.
Q And when you prepared this testimony you had reviewed the version of the well file in the Diamond database?
A Yes.
Q Which again was an electronic document

production, correct?
A Yes.
MR. STODDARD: Thank you.
We're going to introduce Exhibit 1-17.
(Deposition Exhibit 1-17 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document?
A Yes.
Q It's an email from Darryl Gruen sent on November 19th to you with copies on Amy Yip-Kikugawa, Nick Sher, and Karen Shea, correct?
A Yes.
Q And this was sent a day after you sent him your initial draft; is that correct?
A Yes.
Q And it included the subject line, "Attorney-client privilege confidential," with the proceeding number and SED Aliso testimony; is that correct?
A Yes.
Q Do you believe that this was a response to your email or one that originated from Darryl?
A I think it probably originated from Darryl.
Q And it identifies an attachment.

The file name is the proceeding number "SED Aliso Testimony.docx," correct?

A Yes.

Q And the subject line, and the contents says there is testimony attached?

A Yes.

MR. STODDARD: We're going to introduce Exhibit 1-18.

(Deposition Exhibit 1-18 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yes.

Q What is it?

A It looks like the draft testimony that Darryl sent me.

Q And to confirm, you did not write this testimony, correct?

A Let's see, it looks like this version does not include the part of the testimony that I wrote, which was the records section; so that's correct.

Q And the records section that you prepared would eventually be inserted at the end, is that correct, toward the end?

A I think it's before Section C.
Q Was this your first time --
MR. GRUEN: Just a clarification, to the extent that we're starting to creep into the actual questions about the testimony itself, so I just ask --
I'd reiterate just to the extent that the questions go there, if she could be directed to the part of the testimony where the questions are being asked.
MR. STODDARD: Understood.
THE WITNESS: Let's look at this.
Okay. So looking at Exhibit 1-7, it was inserted as Section 3 at the end of the testimony.
MR. STODDARD: Thank you.
Q Was this the first time you saw SED's testimony?
A Yes.
MR. GRUEN: And just clarification, when you say "was this the first time," what time?
MR. STODDARD: The date that she received this email, which was as established in Exhibit 1-17, Tuesday, November 9, 2019.
THE WITNESS: November 19th.
MR. STODDARD: November 19, 2019.

THE WITNESS: Okay.
BY MR. STODDARD:
Q And that day was the first day that you saw at 5:15 p.m. SED's draft testimony?
A Yes.
Q Do you know whether they were preparing it immediately prior to sending it to you, or whether it had been in existence for a while?
A I don't know.
Q And do you know who authored it?
A No.
Q What was your initial reaction?
A Well, it's not the type of report that I would write, but it was drawn strictly from the Blade report, and so I felt like --
I think it adequately represented what the Commission was -- or what SED was looking at for violations.
Q Why was it not the kind of report that you would write?
A Oh, I might have had done more research in the data and been able to add a little bit more depth to some of the discussion.
Q So it was a little bit thin?
A Yes.

Q Did you read it in its entirety when you received it?

A Yes.

Q Aside from your concerns about the lack of support, do you recall whether you agreed with all of the assertions?

A I had some concerns about some of them, one of them being the --

I think there is a statement that was carried over from Blade that said that there were no indications of a leak on -- ever on SS-25, and my review of the records in the well file suggested that there had been indications of leaks on the shoe on that well. And then I was -- I thought I had that turned off.

There was another area that I wasn't --

Oh, I wasn't real sure about issues related to bottom hole pressure, and so I went back and reviewed that more carefully in the Blade report and agreed with that. I think those were the main areas that I went back and looked at.

I felt like I had not read all of the supplemental reports for the Blade report at that time, but I did look at the areas -- the supplemental reports that supported the areas that I wanted to

check on. And I did feel like Blade was very thorough in their investigation and felt like I could support the conclusions that were pulled over into this testimony.

Q Did you review all of the supplemental Blade reports --

Have you reviewed all of the supplemental Blade reports now?

A There is the last volume having to do with casings, whether it's some technical sessions of that that I haven't read yet, or actually I skimmed them, but I feel like I should go back and read them a little more closely.

Q When did you complete your first pass on the supplemental reports?

A Mid-January.

Q I'm going to direct you to page 36 of Exhibit 1-18. And you see there is a comment there from Darryl, and it's on the sentence that reads "External well-control specialists provide necessary experience and expertise; however, underground storage operators should also have personnel with the necessary skills to monitor and manage external specialists, a core skill for gas storage operator."

Do you see that?

A Yes.

Q And then the comment --

Mr. Gruen states "Margaret, do you have the expertise to say something along the lines of 'underground storage operators including SoCalGas should have personnel with the skills to do XYZ, even if they rely on third party well-control specialists such as Halliburton to do ABC. And multiple kill attempts demonstrate..?'"

Do you see that?

A Yes.

Q Did you discuss that comment with Mr. Gruen?

A I don't remember it, but I probably did.

Q Did you understand Darryl to be asking you to expand upon the highlighted sentence and provide further detail?

A No.

Q What did you understand Darryl to be asking?

A If I had the expertise to support a statement that he had written there or something like it.

Q Do you?

A As a petroleum engineer, I think I could say that SoCalGas should have somebody with that type of

experience, petroleum engineering, to oversee their subcontractors or their contractors.

Q And what type of experience is that?

A Some sort of reservoir engineering.

Q So --

A Or drilling or both.

Q So if they have --

If SoCalGas has somebody who is a reservoir engineer, a drilling engineer, then that would be sufficient?

A Yes. Yes, I think they do.

MR. STODDARD: All right. Thank you.

Let's see if I can get it right this time.

I'm going to introduce Exhibit 1-19.

(Deposition Exhibit 1-19 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is an email from Darryl Gruen to you on Wednesday, November 20th, 2019; so a day after he had transmitted the prior draft that we just discussed, and it is transmitting -- and it includes another attachment of -- with the same file name -- no, not

quite the same file name, strike that.

It includes an attachment entitled proceeding number "SED Aliso Testimony" with the date; is that correct?

A Yes.

Q And the content of the email reads "Aliso testimony attached. Darryl."

I'm going to introduce Exhibit 1-20.

(Deposition Exhibit 1-20 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is a revised draft that had been sent by Darryl Gruen on November 20th of the SED portion of the testimony. Please turn to page 37.

A Okay.

Q You'll note that the comment --

So it's slightly formatted differently because of a change in font size and some other formatting changes. But if you look up at the second sentence on the top of the page, that same sentence, "External well-control specialists provide," is there without the comment.

A Oh, yes.

MR. GRUEN: I'm sorry, I'm not tracking.

Is there a comment that is there? My copy, I don't see one.

MR. STODDARD: Sure.

Maybe it would be easier to compare with Exhibit 1-18, and reference, again, on Exhibit 1-18 page --

MR. GRUEN: Oh, I see.

MR. STODDARD: -- 36.

My point is this is the same sentence even though the pagination is different, the comment is gone.

Q Does this --

Do you recall now or does this suggest that you and Darryl had a conversation in the interim regarding his question about your expertise?

A All right. Let me look up -- it looks like the same statement.

Q Okay. Thank you.

Do you know why Mr. Gruen sent this version less than a day later after sending the initial draft?

A This draft has a recordkeeping section in it.

MR. GRUEN: I'm going to just note an objection that that --

Well, I'll strike the objection.

Go ahead.

BY MR. STODDARD:

Q Ms. Felts, can you direct me to the portion of the testimony that has the recordkeeping section in it?

A Okay. Well, you're right. It only has a heading for it on page 68.

Q Did you write that heading or did -- or did it appear in this draft or the prior draft?

A I expect someone else probably wrote it or maybe pulled it off of a draft I sent.

MR. STODDARD: Okay. Moving on.

Introducing Exhibit 1-21.

(Deposition Exhibit 1-21 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is an email from you to Darryl Gruen, no one is copied, and it was sent on Wednesday, November 20, 2019 and the subject line is "Edits to

Testimony." And you see in your response to Darryl where you state "Darryl, I can't get the tracking to work. It's possible it is showing on your computer, but I'm hesitant to put the work into it is doesn't show."

Would I be correct that that is supposed to read "but I'm hesitant to put the work into it if it doesn't show"?

A Yes.

Q The next sentence says "So I'm going to finish my testimony, and you can go ahead and use the SED testimony as is. I don't think I can sponsor it as written."

Do you see that?

A Yes.

Q Were you referring to the draft that Darryl sent the day before that we were just looking at, Exhibit 1-20?

A I don't know if I'm referring to that one or the one prior that you had provided. Things were going back and forth pretty quick.

And I know that I was having a problem doing the tracking on my computer, my PC, but I got that resolved eventually, and I believe I had some concerns that we may have just walked through over

the phone and resolved.

Q And do you recall what your concerns were?

A I think -- I think my main concern may have been the issue with the statements in the testimony that Well SS-25 had never exhibited a leak.

Q So over that single issue you were indicating in this email that you weren't going to sponsor it as written and suggesting that Darryl go ahead and use the SED testimony as is?

A It's possible. I'm usually pretty picky about those things, and that was a fairly inaccurate statement.

Q Were there discussions about what SED would do if you didn't sponsor the testimony?

A Yes.

Q And what was discussed?

A I -- I don't remember exactly, but I believe there was discussion of releasing it without a -- someone supporting it.

Q Releasing it without someone's name on it?

A Yes.

Q Was there any discussion of alternative witnesses?

A No.

Q So after you received this email, as far as

you recall, you think you spoke with Darryl on the phone?

A Well, to correct you, I sent this email. I didn't receive it.

Q I'm sorry, thank you for the correction.

A And I believe we probably discussed it over the phone.

MR. STODDARD: I'll introduce Exhibit 1-22.

(Deposition Exhibit 1-22 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q This is an email from --

Do you recognize this document?

A I don't really recall it, but it appears I wrote it.

Q It's from you to Darryl Gruen dated Wednesday, November 20, 2019, 7:39 p.m., and the subject line is "SED Testimony Cleaned and marked up versions."

Do you see that?

A Yes.

Q And it includes two attachments. One, it appears to be a clean version, and one that says "With Original Footnotes."

Do you see that?
A Yes.
Q You said "Still have to merge mine into this one."
And you are referring there to the documents -- the document testimony that you drafted?
A The records section.
Q "The records section"?
A Yes.
Q And this one you're referring to the testimony that was prepared by Mr. Gruen?
MR. GRUEN: I'm sorry. Objection to the characterization of the testimony calling testimony as "prepared by Mr. Gruen."
That assumes facts not in evidence, and it's a mischaracterization of Ms. Felts' testimony.
MR. STODDARD: Restating.
Q You were merging the section you prepared on records, you were going to merge that one into the version prepared by SED?
A Well, I don't know who prepared it, but it was provided to me by Darryl Gruen.
Q And the email reads "The Clean version has all changed except accepted footnote numbers adjusted. The other version shows all comments,

edits and retains all original footnotes. Margaret," correct?

A Yes.

MR. STODDARD: We might need to take a break for a moment.

No, we don't.

MR. GRUEN: Jack, we can continue this.

Potentially maybe this might be -- or assume might be a good time for a --

MR. STODDARD: Let's just take a quick break.

MR. GRUEN: Do you want to do that?

MR. STODDARD: Yeah, we've been going for another hour or so.

THE VIDEOGRAPHER: Just a moment, please.

We are off the record at 2:30 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 2:47 p.m.

MR. STODDARD: Okay. Picking up where we left off.

Just to circle back, we had just discussed Exhibit 1-22, which to recap included two attachments, which I'm now going to introduce.

The first we'll mark as Exhibit 1-23.

(Deposition Exhibit 1-23 was

marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document?

A Yes.

Q This is a first attachment to the email marked as Exhibit 1-22, and this is the clean version of SED's revised draft testimony which you revised, correct?

A Yes.

MR. STODDARD: Introduce Exhibit 1-24.

(Deposition Exhibit 1-24 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yes.

Q And is this the redline version of the testimony that you revised combining SED's draft with your draft and which was --

I'm sorry.

A Go ahead.

Q -- which was attached to the email now marked as Exhibit 1-22.

Strike that. Correction.

This is your redline of SED's portion of the testimony. It does not include the records section, but this is the redlined version of what was attached to the email marked as Exhibit 1-22?

A Yes.

Q Thank you.

I'd like to note for purposes of the record that this document was missing from SED's initial document production, and we had to specifically request it and received it only two days prior to the deposition.

Turning to page 1 of the document, page 1 of the revised draft testimony, which is actually five pages into the document after the Table of Contents.

Do you see the redline through in the introduction where it states "Drawing on the Blade report and information obtained in its own investigation, this testimony identifies numerous safety (and health) violations of PUC Section 451 related to the uncontrolled release of hydrocarbon gas or methane for 111 days from Southern California Gas Company's (SoCalGas) Aliso Canyon Well SS-25 (SS-25 incident) including many different causes identified in the Blade Report from which the SS-25 incident resulted"?

Do you see that?
A Yes.
Q And that you struck the language "including many different causes identified in the Blade report from which the SS-25 resulted," is that correct?
A Yes.
Q Why did you strike that language?
A Probably because I thought it was redundant.
Q Okay. Please turn to page 11.
Do you see at the top where you deleted the discussion of groundwater as a source of corrosion?
A Yes.
Q And down at the bottom of the page 11 where there is a sentence regarding groundwater and microbes, "a form of Archaea caused the corrosion"?
A Yes.
Q And then below that is another sentence regarding MIC as the mechanism of corrosion; do you see that?
A Yes.
Q And that those sentences are all deleted in your redline; is that correct?
A Yes.
Q And why did you delete those sentences related to microbial -- Blade's findings of microbial

corrosion?

A Well, at the time I felt like the information that was drawn from the -- it was drawn primarily from the main report, and I had not read the details of their analysis, their lab analysis that showed how they came to that conclusion. And so I just wasn't real solid on supporting those statements at that time; so I deleted them.

Since then, I've looked at all of those reports and read the underlying investigation data, and I could have supported it had I had the time to look at those; so I think it was sound science.

Q Okay. Will you be amending your opening testimony to add those findings back in?

MR. GRUEN: I'm going to object to that in that it calls for attorney work product and attorney-client privilege.

That's a deliberation that is still being considered by SED.

BY MR. STODDARD:

Q Ms. Felts, these portions of the testimony that you -- of the draft testimony that you deleted related to microbial corrosion, did you put them back into the testimony that was served, do you recall?

A I don't remember.

Q Referring back to Exhibit 1-7. Please take a moment to review and just confirm whether you added any of that language back in.

MR. GRUEN: Just so I'm clear, the question is to compare page 11 of Exhibit 1-24 with comparable page on Exhibit 1-7?

Am I tracking correctly?

MR. STODDARD: I'm asking more generally whether --

I'm giving her time to flip through the relevant sections of the document to identify whether she understands -- or whether she added this language back into the document, not particularly page 11 of the document.

MR. GRUEN: I follow. Okay.

THE WITNESS: It doesn't look like I added it back in.

BY MR. STODDARD:

Q But now since the opening testimony, you've reviewed the relevant sections of the Blade report, and you're more comfortable with their conclusions on that issue; is that correct?

A Yes.

Q So would it be fair to say that at the time that you served your opening testimony, you hadn't

considered the entirety of the Blade report?

A Some of the technical supplements to the Blade report were -- I had only glossed over, and so I felt like I really needed to go back and look at that in detail.

Q I'm going to direct you to page 42 of Exhibit 1-24.

A Okay.

Q Same question here, do you see where it says "Some of the 7-inch casing connections were seeping gas at the outside of the casing and then the carbon dioxide in the gas was likely a nutrient for the methanogens," and you deleted this language, correct?

A Yes.

Q And separate from the reference of methanogens, did you also doubt Blade's conclusions regarding the 7-inch casing connections?

MR. GRUEN: I'm going to object to the characterization of her testimony as doubting Blade's conclusions.

The objection is that it's a mischaracterization of her testimony thus far.

MR. STODDARD: All right, I'll restate it.

Q Ms. Felts, did you have similar concerns related to those you had with respect to the section

on MIC related to Blade's conclusions regarding the 7-inch casing connections?

MR. GRUEN: Same objection.

I think for clarification, she --

Well, I'll just note the same objection. It's concerns with the conclusions is a misstatement of testimony.

BY MR. STODDARD:

Q Ms. Felts, why did you strike that language that I referred to?

A Okay. So the statement is that there was seeping gas from a 7-inch casing which then fed or served as a nutrient to the microbial community that was causing the problem, so -- or causing the corrosion.

The main report lacked substantive support for that. And so it was necessary to go back and understand the tests that Blade ran on the 7-inch casing joints that showed or proved that there was leakage.

And so I needed to completely understand that part of the investigation to support that statement, and I -- had I really felt well about that, I would have also felt good about the seeping gas serving as a nutrient; so I deleted both sections

just because I hadn't gotten to a sound understanding of what they had done that caused them to make that statement in the main report.

Q And now you feel comfortable having reviewed that section of the report that Blade's conclusions with respect to microbially influenced corrosion are well supported?

A I think they did a pretty good job of the review and the science.

MR. GRUEN: I'm sorry, she wasn't finished with her answer.

THE WITNESS: That's okay.

BY MR. STODDARD:

Q And that the --

And their conclusion that there may have been Archaea microbes?

A I really don't have an alternate opinion other than what they concluded on that. And they base that on their scientific research and knowledge; so I think it's probably a good conclusion.

There may be something else out there, but I'm not aware of it.

Q And you have faith in Blade's scientific process and conclusions?

A I do. I think they did a good job.

Q But you didn't speak with anybody at Blade or interview anyone at Blade, correct?
A No, I didn't.
Q Did you evaluate the credentials of the Blade personnel?
A I believe I did look at their credentials, and also I think I looked up some information about them online just to see what type of work they've done before, and it seemed like they had a fairly good history in the industry.
Q Did you review the description of Blade's sampling and microbial analysis protocols?
A Yes.
Q And you felt that those were sufficient and complied with standard procedure?
A I think so, based on my experience.
Q I'm going to direct to you page 20 of Exhibit 1-24.
A Okay.
Q Do you see the sentence in the second full paragraph where it says "The SS-25 temperature and noise logs had never shown an anomaly related to casing integrity"?
A Yes.
Q And is that your comment in the margin?

A Yes.

Q And the comment reads "I know this is a quote. However, you should know that temp and noise surveys on SS-25 showed one or more leaks from 1978 to 2012. But, these leaks were not shallow."

What was the basis for that comment?

A I had looked at the well file, and I was just reporting that there was something in the well file that showed that there were leaks.

Q And what was that something?

A Temperature surveys, primarily. I believe there is one or more noise surveys.

Q And you think --

You believe that both the temperature surveys and the noise logs showed leaks?

A There is no question that the temperature logs show leaks. The noise surveys seemed like they were inconclusive. Sometimes I think because they ran the noise logs under the wrong circumstances.

Q And this was based on your review of the electronically produced logs that were in SED's Diamond database?

A Yes.

Q And you disagreed with Blade on this point, correct?

A Yes.

Q Is it your understanding that Blade's investigation was conducted over a period of several years?

A Well, from 2015 to at least 2018.

Q And earlier you stated that you believed Blade did a very thorough job, correct?

A I think they did. I -- my -- I think --

And this is just my probably assumption is that they didn't have access to the same information I've had access to when they came to this conclusion. I don't know that for a fact. I just know they received some really late data from SoCalGas. And it's possible that they were basing their conclusions on DOGGR records, where they would not have seen this.

Q And, again, you did not review the records that Blade Collected or any of the productions and data responses that SoCalGas sent to Blade in connection with preparing your testimony, correct?

A That is correct.

Q Or in connection with this comment, correct?

A That's correct.

Q If Blade hadn't reviewed these records -- actually, strike that.

And these records, you found them in the well file that was available in the Diamond database, which included records related to SS-25, correct?

A Yes.

Q If Blade didn't review the records related to SS-25, do you believe that their investigation would be thorough?

A For what --

For the primary work that Blade was doing, I don't know if they needed the historical records. They needed the construction records; so they had what they needed from the Department of Oil and Gas records that were on file there.

This was just one area where for some reason they either were told or came to the conclusion that there was no -- had not been any prior leaks on that well. I don't --

There is no question in my mind that if they had looked at the records that I looked at, the temperature surveys, they wouldn't have said that; so I have to conclude they didn't see them.

Q And do you believe that the alleged fact of historic leaks is relevant to the alleged 451 violations in your testimony?

MR. GRUEN: I'm going to object that that calls

for legal conclusion.

I just am noting an objection for the record.

And more broadly just to the extent that there are questions that go to any violations in testimony that asks for a legal basis for violations, we're going to restate an objection. And we'll note discussion in the pre-hearing conference related to that.

But I wanted to note that objection for the record.

Having said that, she can answer the question.

THE WITNESS: Can you ask the question again?

BY MR. STODDARD:

Q Is your opinion regarding the presence of a historic leak dating back to 1978 at SS-25 relevant in your view to your alleged -- to the alleged violations of 451 in your testimony?

Let me restate that.

A Okay.

Q If there are no leak --

If there was no historic leak at SS-25, is that a mitigating factor in your view related to SoCalGas's O&M practices at SS-25?

A The reason for my concern in making the statement that there was no leak was just that it was an inaccurate fact in a report, and I'm a records person, so I like things to be accurate and based on records. And certainly since my testimony -- the written part of my testimony that went into this document had to do with recordkeeping, I was particularly sensitive to the fact that everything in this testimony should be accurate as it was recorded in records.

And in this particular case, the record file for SS-25 included a number of annual surveys that documented a leak at the bottom shoe of the well. And because this particular file excluded any analysis or memos about that ongoing leak, whereas other well files including 25A and 25B had that kind of -- those kind of notes in them, I felt like it was something that I should call attention to, at least among the PUC people.

It has, I think, little bearing on the -- the violations that were cited one way or the other.

Q Okay. You stated that you are a records person so you like to have things be accurate and based on records, correct?

A I like them to -- statements to accurately

reflect what is in the record.

Q And this statement, based on your review of records, you believed Blade was incorrect?

A Blade may have been correct on what they were looking at. It was incorrect based on the documents review I had done.

Q Did you endeavor to look at the underlying records on Blade's other findings in the Blade report?

A I think I considered everything that they made available. And certainly looked at -- looked at the testimony in light of the records that I had available to me, and this was the one that I had the most concern with.

Q Did you communicate to SED which records you thought would be necessary for purposes of being able to support the testimony, or was it simply accepting what SED gave you and limiting your review to that?

A I'm not sure I understand your question.

Q Let me take a specific example.

So you indicated, and correct me if I'm misstating you, but you indicated that you disagreed with Blade's conclusions regarding the -- their interpretation of the temperature logs or their statement regarding the historical noise logs at

SS-25. You disagreed with that based on your review of the records, correct?

A What I disagreed with was the statement the SS-25 temperature and noise logs had never shown an anomaly relating to casing integrity. That's the statement I disagree with.

Q And that was based on your review of records?

A Yes, which show anomalies relating to casing integrity; so the statement can't be correct. Now, it may not --

You said that I disagreed with Blade's interpretation of logs. I don't know that they had access to those logs.

Q Did that raise any doubts in your mind as to Blade's other findings or conclusions?

A No.

Q So taking an example on page 17 of Exhibit 1-24 regarding failure to implement a risk assessment program, it cites to the Blade report in the first sentence, "Corrosion was not detected on SS-25 because the 7-inch casing wall thickness on the SS-25 had never been inspected."

Did you verify that through inspection of records?

A There is no evidence of an inspection of the wall thickness in the SS-25 well file.

Q And with respect to Blade's identification of a failure to implement a risk management plan as a root cause, did you confirm their conclusion that it hadn't been implemented based on a review of records?

A Yes, there is no risk assessment program or any documentation of a risk assessment in the well file.

Q Did you look outside of the well file?

A We asked many -- in many different ways for risk assessments and have consistently been told that there are no records.

Q That's based on your review of which documents?

A Well --

Q You said "we asked."

Who are you referring to?

A I'm referring to SED in data requests.

Q And those are data requests that were made available to you through the Diamond database?

A I wrote some of those discovery questions, and the answers came back that there were none.

Q Turning back to the temperature logs.

What experience do you have with respect to

interpretation of temperature logs?

A I studied that in petroleum engineering, and other than that, none --

Nothing specific. It's not a fine science.

Q And could a temperature log be indicative --

Could a temperature log anomaly be indicative of something other than a leak?

A Well, I think maybe, but these -- these temperature logs in the SS-25 well file actually have notes on them that say "potential leak." It's pretty obvious, and the temperature survey, the numeric temperature survey printout shows a reduction in temperature, so --

And if you compare that well log or that well file and the temperature surveys in that well file to other well files at Aliso, you will see that a similar thing was happening at other wells, and there was responsiveness to it by SoCalGas.

For some reason not so on -- or it doesn't appear so in the well file for SS-25. It's not a one-time thing in this well. It was happening across Aliso.

Q You mentioned the temperature reading spike that would occur and indicate an anomaly --

A Actually a drop in temperature.

Q Right.
A Yes.
Q So the drop in the temperature that you can see on the temperature log --
A Yes.
Q -- correct, could that possibly be due to the presence of water behind the casing?
A Not likely at the shoe where this leak was occurring. It's very a common leak in these wells.
Q And do you recall what depth that was?
A Probably very close to the bottom, so it would be the bottom shoe.

So this well was about, I don't remember exactly, 8300 feet deep; so it would have been around that depth.

Q Okay. Direct you to page 28. Again, here same issue, statement regarding annual temperature and noise logs, and you deleted the clause that says "no anomalies were found," and included a comment that says "Wrong, we could replace the Blade footnote with SS-25 well file."
A Okay.
Q Again, you're disagreeing with Blade here.

Do you recall any other instances where you disagreed with Blade?

MR. GRUEN: I'm going to object. Asked and answered.

THE WITNESS: Well --

MR. GRUEN: She can answer the question, but it's been asked and answered before.

THE WITNESS: This is --

I mean, there might be other places in the testimony where I struck the thing having to do with the temperature survey, but I think that was -- that and the MIC issue were the two things.

BY MR. STODDARD:

Q I'm going to direct you to page 30, the sentence says "Kill operations where a fluid being pumped into a well while the gas is escaping at a high rate requires a detailed transient model to define the operational parameters."

And I apologize, I was reading that before you got to the page.

But do you see where I'm talking, it's highlighted?

A Uh-huh.

Q And you flagged it and said "Let's talk about this."

Do you know why you wanted to talk about it?

A I don't really remember. Something

triggered that thought. Possibly I might have wanted to talk about the bottom hole pressure.

Q What about bottom hole pressure?

A Just that that seemed to be -- let me back up.

Using the lower-than-actual bottom hole pressure might have been a problem for the kill operations. They couldn't wait -- or were not waiting there, the fluid they're pumping down the well to a heavy enough weight to overcome the reservoir pressure.

Q Again, Ms. Felts, you don't have any experience with well-control operations, correct?

A Well, not directly, but as an engineer I studied it, and it's not a -- it's not a fine science. It's just an engineering calculation.

Q An engineer with a suspended license, correct?

A I don't have a suspended license. Why do you say that?

Q I thought you indicated at the beginning of our deposition that your license was on hold.

A No, I have a general -- I have a general contracting license that's on hold, just has nothing to do with this.

Q So your engineering license is active?
A I don't have an engineering license --
Q Do you have any certification --
A -- in California.
Q In other jurisdictions?
A No.
Q But you have a general contractors license?
A Yes, that was --
Q And that's what has been put on hold?
A Well, I put it on hold. You can --
If you don't want to pay $500 a year for your general contracting license, you can pay $200 a year and then reactivate it when you have a contract; so that's what I did. It's still valid.
Q And is that related to work that you do on any energy facility context?
A Well, it's a general contracting license, and I used it for years doing drilling, monitoring wells and cleaning up hazardous waste sites. It has a HAZ rating with it.
Q Okay. Direct you to page 33. See the section --
I'm sorry, I'll let you get there.
A Okay.
Q Second full paragraph, second half, "It is

probable that continued pumping from the surface might have kept up with the fluid loss, but surface plumbing failures prevented the well from being kept filled."

Why did you delete that sentence?

A I think I deleted it because I didn't think it was necessary for the testimony.

Q Same question for the next sentence, "The use of fresh water and clear brine contributed to the attempt's failure because of fluid loss into the formation and loss of hydrostatic pressure, which allowed the well to flow after the kill attempt."

A Same point.

Q Refer you to page 46 and 47. There is a discussion here related to the chemical nature of groundwater.

A Yes.

Q And the sentence starts "Factors that control the chemical nature of the groundwater are mineralogy, transmissibility, and topography."

Why did you delete this paragraph?

A Here again, I thought this was too much detail and not contributing to the testimony.

Q Did you disagree with the substance?

A No.

Q Factual accuracy?
A No. I just thought it was drawing way too much detail into the testimony.
MR. STODDARD: I'm going to introduce Exhibit 1-25.
(Deposition Exhibit 1-25 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this email, Ms. Felts?
A Looks like it's an email from Darryl to me. I don't remember it.
Q It's the day before your testimony was served; is that correct?
A Yes.
Q And the email reads "Margaret, I'll call you about this shortly. Darryl." And it has an attachment titled "Recommended Fixes."
A Okay.
MR. STODDARD: I'm going to mark Exhibit 1-26.
(Deposition Exhibit 1-26 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?

A Not really.
Q This was the attachment to Exhibit 1-25, which was Darryl's email to you with the attachment "Recommended Fixes," and Darryl said he was going to call you about it.
Do you recall Darryl calling you about it?
A No, but ask questions if you want.
Q Okay. Do you know if this document was incorporated into your testimony?
A I don't recognize it. Do you know where it is in the testimony?
Q I'll refer you to Exhibit 1-7.
A I have that here.
Q Turn to page 77. 76.
A Okay.
Q Does this refresh your recollection?
A Okay. I see where it is. I understand what it is. Okay.
Q Okay. I take it you didn't write this section, correct?
A No.
Q And it doesn't sound like you reviewed this section either, correct?
A I'm sure I read it because I read the whole testimony before it went out.

Q But you don't recall discussing it with Mr. Gruen?

A Well, we probably discussed it because we went over all of this before it went out. But looks a little --

Let me see.

Okay. We probably just walked through it toward the end.

Q Okay. So you don't recall feeling uncomfortable about the fact that Mr. Gruen sent you a new section of your testimony that you were agreeing to sponsor the day before you were due to serve it?

A Well, I think this was something that was probably already being discussed, and it just got finalized here.

Q Discussed with you?

A Yeah.

Q But you don't recall?

A Well, I don't recall this format of it. I guess this is how it looked when it was printed out from the email. This looks more familiar, what is in the testimony. It's just a formatting thing I see.

Q Looking at the one in the final testimony --

A Okay.

Q -- starting at page 26.
A Okay.
Q Do you recall --
A 76 or 26?
Q I'm sorry, 76. Thank you.
A Okay. Okay.
Q Do you recall discussing "Solution 1, Production casing should be cemented to the surface" --
A Yes.
Q -- with Mr. Gruen?
A Yes. This is --
That was a common finding, yes.
Q And do you recall doing any research or investigation on this recommendation?
A Well, I'm sure it came right out of the Blade report.
Q So for purposes of this, you are relying on the Blade report and you're satisfied with their findings on this issue?
A For purposes of almost the whole report, I was relying on Blade, and I felt pretty comfortable with it. We just went over the areas that I wasn't comfortable with.
MR. STODDARD: Okay. Thank you.

I'm going to introduce Exhibit 1-27.

(Deposition Exhibit 1-27 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yes.

Q And this is an email from Darryl to you --

A Yes.

Q -- marked "Attorney-client privilege," attaching a revised or a -- I'm sorry, with an attachment titled "Felts.2019 Draft Testimony 112119," correct?

A Yes.

MR. STODDARD: Introduce Exhibit 1-28.

(Deposition Exhibit 1-28 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A This looks like the recordkeeping section.

Q Is this Darryl's revisions to the initial draft recordkeeping section that you sent him?

MR. GRUEN: Objection. Calls for speculation, assumes facts not in evidence.

BY MR. STODDARD:

Q Is this a revised version of the draft that you initially sent to Darryl?

A It looks like there is a couple of comments on it, all for me to confirm footnotes.

Q Do you see the comment on page -- the pages are not numbered, the second-to-last page of the document?

A Yes.

Q Is that a comment from Darryl?

A In the red -- little red box?

Q Yes.

A Yes.

It says "Margaret to confirm accuracy of footnote."

Is that the one you're looking at?

Q Yes.

And you believe that's a comment from Darryl?

A I think so. It says "GD1." That's his initials and number 1.

Q Referring back to Exhibit 1-16 --

A 1-16.

Q -- for comparison purposes --

A 1-16. I don't seem to have it. There

should be one in this stack.

THE VIDEOGRAPHER: Counsel, while she is looking, may I have a moment to change my disks?

MR. STODDARD: Yes.

THE WITNESS: I got it.

THE VIDEOGRAPHER: This is the end of disk number three, Volume Number 1, in the deposition of Margaret Felts on February 5th of the year 2020.

We are off the record at 3:39 p.m.

(Off the record.)

THE VIDEOGRAPHER: This is the beginning of disk number four, Volume number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are on the record at 3:44 p.m.

MR. STODDARD: Thank you.

Q Referring back to where we were, we were comparing documents 1-16 with 1-28.

And for sake of context, 1-28 is a later version of the same document as 1-16, except that 1-28 was sent from Mr. Gruen to Ms. Felts the day before her testimony was filed -- the day before her testimony was served.

I'm going to direct you to page 2 of both documents at the bottom.

A Okay.

Q Do you see the sentence starting "The significance"?

A Yes.

Q "The significance of these files" --

In the older document it states "The significance of these files is that they contain records not included in the SS-25 Well File but relevant to the operation, maintenance and closure of Well SS-25 because these wells share similar design," and it goes on.

In the more recent version that Darryl sent to you on the 21st, it states "The significance of these files is they contain record types such as Interoffice Memos, handwritten field notes, analyses, and reports that are not included."

That's a change relative to your original draft; would you agree?

A Yes.

Q Did you make that change or did Darryl make that change?

A I think I made --

MR. GRUEN: Objection. Calls for speculation as to the actions of Darryl Gruen.

BY MR. STODDARD:

Q Did you make that change?

A I made the change orally to Darryl.
Q So you had a phone call to discuss the prior draft?
A Yes.
Q Do you believe that all changes in this document were made by you pursuant to that phone call?
A Well, there is one on the front page that I know was, and that was where we deleted a paragraph I wrote about 451 and slightly modified the first paragraph, I think, so --
And in this one I know, because Darryl wouldn't know about interoffice memos, handwritten field notes and analyses and reports. I had to have said that.
Q Why wouldn't Darryl know about that?
A Because he hasn't read that well file, I don't think.
Q And how about looking at the footnotes on page 2?
A Footnotes on page 2?
Q Yeah.
MR. GRUEN: Of which exhibit?
MR. STODDARD: I'm sorry, of Exhibit 1-28.
THE WITNESS: Okay.

BY MR. STODDARD:

Q They did not appear in Exhibit 1-16, correct?

A Okay. That's true, but I would have -- I would have told him what the footnotes had to be. He wouldn't have known.

Q Okay. And do you believe that's likely the case?

Do you recall the conversation you had with Darryl about these changes?

A Yeah.

Q Do you think all of the changes were probably made pursuant to --

A Yes.

Q -- your discussion?

A Uh-huh.

Q I'm going to direct you to the first page of Exhibit 1-28.

A Yes.

Q The second footnote related to Public Resources Code Sections 3106, 3180, 3181, 3220 and 3403.5.

Did Darryl also make that change at your direction?

A No. I would guess he probably actually put

the code sections in there because that's related to, see footnote 2, so we probably looked at it while we were on the phone, and he probably put it in.

Q But you're not sure?

A I'd have to look up the code and tell you for sure. But if it's -- if it's DOGGR codes, then I put it in. If it's PUC codes, he put it in.

Q Okay. So it might be helpful for purposes of the record actually then to introduce them so you can confirm based on the subject matter.

A Okay. That would be helpful.

MR. STODDARD: We'll mark this as Exhibit 1-29.

(Deposition Exhibit 1-29 was marked for identification and is attached hereto.)

MR. STODDARD: I apologize the first page is Section 3008, which you don't cite to; its just definitional. It's just definitional the first page, that's 3008.

THE WITNESS: Right.

BY MR. STODDARD:

Q That is not something that you cite. But if you turn to page 2, it's Section 3106, take a moment to review it.

MR. GRUEN: I'm sorry, just for the record, it

appears as if there are multiple page 2's in the document; so just to --

Could we clarify which page 2 is being referred to for the record?

MR. STODDARD: Yeah.

So to clarify what has been marked as Exhibit 1-29 is California Public Resources Code Sections 3008, 3106, 3180, 3181, 3315 and 3320, 3316.2 and 3403.5, and I -- they are stapled together.

And I was directing the witness to the second page of the packet, which is Section 3106.

MR. GRUEN: Understood. Thank you.

THE WITNESS: Okay.

BY MR. STODDARD:

Q So you've reviewed the document.

Having done so, did you add these citations?

A I would have added them.

MR. STODDARD: Okay. Thank you.

We can take a break if it's okay with you.

MR. GRUEN: Okay.

THE VIDEOGRAPHER: We are off the record at 3:52 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at

4:25 p.m.

BY MR. STODDARD:

Q Ms. Felts, I'm going to reference with the next questions Exhibit 1-7 --

A I got it.

Q -- which is your opening testimony that was served.

A Okay.

Q Turning to pages 3 through 6 of this document.

A 3 through 6?

Okay.

Q Do you see violations starting at number 95 and going through 320?

These are violations that relate to SoCalGas's assertions of attorney-client or attorney work product privilege; is that correct?

A Lack of cooperation, is that what we're talking about? Am I looking at the wrong thing?

Q Yes, 95 to 320, "Lack of Cooperation."

A 320, yes.

Q And for each of these --

If you want to take a moment to review, you can, but for each of these, it relates to SoCalGas's privilege claims?

A Okay.
Q And that's the majority of the violations that are asserted in your testimony, do you agree?
A Numerically, yes.
Is that what you're talking about, "the majority"?
Q Yeah, the majority.
A Yeah, okay.
Q Yeah. All right. Now, turning to Section 2, C.2 that is referenced in association with these violations.
A And page?
Q I'll have that for you in a second. 52.
A 2, I see 2 on page 52.
Q Yeah.
And earlier you stated that you did not draft this section, correct?
A Yes.
Q And that is everything related to the privilege issues, correct?
A Yes.
Q But you are sponsoring this portion of testimony, correct?
A Yes, I agreed to sponsor the entire testimony.

Q How did you get comfortable to sponsor this section?

A Well, I guess I went over these particular violations with -- with Darryl and discussed them with him.

Q When did you do that?

A It would have been prior to the testimony going out.

Q And you feel that you have a good understanding of the underlying facts related to this issue?

A Well, I think I have a pretty good understanding of what was happening.

Q Did you review any underlying documents associated with these violations?

A I reviewed the documents that were attached, the exhibits.

Q Do you recall any specifically?

A Not without looking at them. I should remember them. I think I just looked at them yesterday.

Q But earlier it does not include the privilege log associated with SED 16, correct?

A There was a point in time when I looked at the privilege log. I just can't really answer any

questions about it unless you show it to me.

Q Do you recall reviewing any of the documents that SoCalGas withdrew its privilege claims -- for which -- let me restate that.

Do you recall reviewing any of the documents that are the basis for the alleged violations?

A These are the documents.

Q Related to the privilege issues?

A The documents that you eventually produced --

Q Correct.

A -- I'm pretty sure I saw them. I don't --

It seems like I remember emails, but I'm not --

I mean, I can't tell you the content of them just as I sit here today.

Q Do you recall reviewing any correspondence or letters between SoCalGas and SED related to meet-and-confer meetings --

A No.

Q -- on the privilege issue?

A Not specifically.

Q Do you recall reviewing any data responses related to the privilege issues from SoCalGas?

A I think I probably did. If you want to ask

specific questions, you're probably going to have to show me the documents.

Q And do you feel as though you understand SoCalGas's position with respect to its initial privilege assertions relative to the privilege -- relative to the documents that are at issue in the privilege log?

MR. GRUEN: Jack, if I may, I think there is a --

I'm going to object to the question as vague in that if there is a particular area in the testimony that you want to direct -- or documents, the witness has called for documents that you can use to ask questions.

But the vagueness in this question is the actual position.

Without identifying the piece of testimony or the document where it's stated, it's going to be hard for the witness to answer a question like that.

MR. STODDARD: Understood.

I'm trying to understand the witness's process with respect to sponsoring this testimony; so I'll restate the question.

Q Just as a matter of fact, did you consider SoCalGas's position with respect to the privilege

issue in evaluating the testimony that you were provided by Mr. Gruen?

A Are you asking me if I understood why SoCalGas was claiming privilege?

Q Yes.

A I think I -- I think I understood what SoCalGas said was their purpose in claiming privilege. That's probably not the same as saying that I understood it. I --

MR. STODDARD: Offer this as exhibit.

(Deposition Exhibit 1-30 was marked for identification and is attached hereto.)

MR. STODDARD: Take a moment to review that document.

MR. GRUEN: Just, Jack, just for clarification, you want her to review the entirety of this document?

MR. STODDARD: No. I want her to review it to the extent she is --

If you need additional time, just ask for it. If I ask a question, we can see --

THE WITNESS: Why don't you ask a question and see how far we can go with it?

BY MR. STODDARD:

Q Okay. Do you recognize this document?

A I've seen it.
Q Did you review it in connection with preparation of your testimony?
A No, I did not have it until after then.
Q Okay. Thank you.
Ms. Felts, I'm going to direct you to page 62 of Exhibit 1-7.
A Okay.
Q Middle of the page, do you see where it starts "By SED's count, approximately 18 additional documents were released"?
A Yes.
Q And then it says "Each of the 95 pages that SoCalGas did not release on the grounds of attorney-client or attorney work product privilege is a Section 451 violation because it delayed SED's ability to get this information as part of its pre-formal investigation."
Do you see that?
A Yes.
Q Are you aware of any specific information in the 95 pages that you believe was important to SED's investigation?
MR. GRUEN: Objection. Mischaracterizes the use of the term "investigation" as -- in the past tense

mischaracterizes it.

The investigation is ongoing.

THE WITNESS: The way I could answer that is that apparently this, in part, relates to the DR 16 response. And if portions of the DR 16 response were not available, it would be difficult to nail down some of these violations. But since I don't know which pages specifically out of that response were withheld, I can't answer.

BY MR. STODDARD:

Q Well, I'm asking, Ms. Felts, what this information in your testimony is referencing because there is no citation, so I'm not sure.

But it says "Each of the 95 pages that SoCalGas did not release on the grounds of attorney-client or attorney work product privilege is a Section 451 violation because it delayed SED's ability to get this information as part of its pre-formal investigation," and I'm asking what that information was in your view?

A I think this information refers to the 95 pages that SoCalGas did not release.

Q Do the contents of those 95 pages matter in your view as to whether or not it's a Section 451 violation?

A I don't think it's the contents that is the issue here. I think it's the release of the documents that were requested. So it goes to the investigation overall.

If you don't know what is in the records, you have to assume that it's possibly not safe -- a condition or relevant to a condition that is not safe; so it prohibits the complete investigation by not being able to look at the records.

Q That's not what this sentence says though.

It says that SoCalGas did not -- that "Each of the 95 pages that SoCalGas did not release on the grounds of attorney-client or work product privilege is a violation because it delayed SED's ability to get this information as part of its pre-formal investigation" seems to be suggesting that there was information in there which was material to the investigation that SED was prevented from getting.

Would you agree?

A And I think that's the assumption that they made when they didn't get it.

So it's made prior to receiving the 95 pages. You can't make a judgment on the content of something that you haven't received yet; so it's the delay that is the problem.

Q Are you --

Is it the case, then, that you believe that SED did not receive these pages at the time that these violations were asserted?

A I'm actually not sure when the pages were turned over.

Q Okay. Above that, do you see the sentence that says "By SED's count, approximately 18 additional documents were released"?

A Yes.

Q And there are violations both for those 18 documents and the 95 pages; is that correct?

A I think that's correct.

Q Can you explain why in one instance the violations are linked to documents and in the other it's pages?

A That's --

I don't know. That was a choice of wording, I suppose. Maybe somebody counted up the pages in the 95 number.

Without having the 18 documents in front of me, I can't tell you whether that's 18 individual documents, therefore 18 pages, or 18 multiple-page documents.

Q In general, discovery requests are for

documents, not for pages, would you agree?

A Yes.

Q Do you think it would be more reasonable to assert violations based on documents that were withheld versus documents that happen to have multiple pages that were withheld?

A I don't really have any history on that as far as the way violations are counted.

Q But you are sponsoring this testimony, correct?

A Yes.

Q So why in your view should violations be calculated on the basis of individual pages for multipage documents?

MR. GRUEN: I'm going to object.

This line is calling for legal conclusion as to how violations are counted. This is a legal question that is appropriate for briefing, not questioning of the witness.

She can answer if she wants to, but this is -- in SED's view this is a waste of time.

THE WITNESS: Without looking at both sets, the 18 and the 95, I don't know why it was chosen to call one documents and one pages, but I would expect that the 95 pages is probably 95 documents; so other than

that, I think -- I think it should be consistent. It's probably my fault for not checking it.

MR. STODDARD: Thank you.

Q In the set that you did review, do you recall noticing any duplicate documents? Again, this is related to the --

A Privilege.

Q -- the privilege, the 95 or the 18.

A I don't recall offhand, but duplicates are very common in SoCalGas responses. Certainly in DR 16 there were duplicates upon duplicates of emails.

Q And if there were duplicates of documents in this data set, would that change your assessment as to whether or not it should be a violation?

A If the duplicates should be a violation?

Q If the withholding of the duplicate for basis of privilege should have been a violation of 451 and Rule 1.1?

A Well, I think you're making the assumption, again, that the -- I could assess the delay of producing things I don't know what they are, you know, ahead of time because I wouldn't have known that there were duplicates in that set.

All I know from a privilege log is that

you're claiming privilege for X number of documents, and you probably had a page count on them in the log, but --

So you claim the privilege -- or SoCalGas did then. That took a certain amount of time to get the documents, and that's the delay, and that's the basis of the assessed penalty.

Q Okay. Turning back to the beginning of Exhibit 1-7 --

Actually, set that aside for a second. I'm going to ask some other questions without referencing a document.

Ms. Felts, what experience do you have with -- what prior experience do you have with root cause analysis investigations?

A I've only reviewed root cause analysis. Mostly related to pipeline cases.

Q How many root cause analyses have you reviewed?

A I don't have an exact count, but I'd say probably at least over 50.

Q And you said mostly related to pipeline cases; is that correct?

A Yes.

Q Do you recall any that were related to gas

storage fields?

A No.

Q Are you familiar with the phrase "technical root cause analysis" as opposed to root cause analysis?

A I wouldn't know the difference if there is -- if there is a difference.

Q So no?

A Not in the field as it would apply to this type of incident.

Q And you say you've reviewed over 50 root cause analyses; is that correct?

A Yes.

Q Have you ever prepared a root cause analysis?

A No.

Q Or been on a team that was preparing a root cause analysis?

A No.

Q Have you overseen preparation of a root cause analysis?

A It's possible that at the refinery and at Celanese I was involved in overseeing root cause analysis on some incidents.

Q Prior to this matter, what was the most

recent root cause analysis that you can recall reviewing or being involved in?

A In the San Bruno case I reviewed all of the historical analyses that were provided, and there was a whole archive of them at PG&E.

Q Was that root cause analysis prepared by the NTSB; is that correct?

A No. These would have been either in-house by PG&E or by external third-party contractors and -- for PG&E.

Q And in your experience how do those prior root cause analyses compare to the Blade report in terms of volume and length?

A It was quite a variation depending on the incident and probably the significance of the outcome of the incident. But I would say overall the Blade analysis was far more extensive and detailed, but the engineering or technical analysis of the pipe itself is very similar.

Q So the metallurgical piece?

A Yes.

Q And in reviews of other root cause analyses that you've done, have you looked only at the report, or do you also look at underlying data, information, that was collected by the investigator in the course

of preparing a root cause analysis?

A I've generally had access to all of the data and underlying records, assuming they're available. Sometimes if you're going really back in history, all you get is the report. But most of a metallurgical analysis would have lab reports attached to them and photographs and basic information that the report relied on.

Q And in this instance have you been offered access to review that information for the Blade report?

A I would say that a lot of it is in the supplemental technical reports that were provided in the additional volumes.

Q But beyond the supplemental reports, the actual data they collected or, you know, images that they didn't include in the report ---

A I haven't reviewed anything outside of what they provided.

Q What is your understanding of the purpose of a root cause analysis investigation?

A Generally?

Q Generally.

A To determine what the cause of an incident was or a failure, pipeline failure, a well failure.

Sometimes it's an operational issue that caused a problem; so it's generally to determine what the cause is of an incident.

Q So that you can prevent similar incidents from occurring in the future; would you agree?

A Well, that's a good start. If you can figure out what caused it, then you can figure out how to prevent it in the future.

Q But would you agree that that's one of the purposes of a root cause analysis is to identify the causes in order to prevent similar -- in order to prevent reoccurrence of similar events?

A It's one.

Q And would you agree that a root cause analysis investigator should include all potential causes?

A Well, I mean, if they did a really good root cause analysis, they should be able to determine what the cause was, not a range of causes.

Q In conducting their investigation though, when they're considering potential causes for purposes of scoping their investigation, would you agree that they should include all potential causes, or do you think they should circumscribe it?

A I would think a good engineering review

would include a range of possibilities at the front end, and then you would start eliminating them pretty fast because you would want to focus in on where the data is leading.

Q And that the root cause analysis investigator should follow the data toward what they identify as a root cause?

A I think so.

Q Regardless of whether or not that root cause relates to something that is required by law?

A I don't think required by law has much to do with a root cause analysis.

Q Regulation?

A Same thing. I mean, whether it's required or -- a required activity or not, the cause is still going to be technical, unless you're looking at an operational issue, if somebody did or did not do what they were required to do and caused an accident, say.

Root cause analysis could be performed on a lot of different kinds of incidents, like car accidents, you know, and purposes can range too. A lot of them are called for by insurance companies. They just want to know where to assign liability. They don't care whether it gets fixed.

Q Referring back to Exhibit 1-7 --

A Okay.
Q -- direct you to pages 7, 7 to 9.
MR. GRUEN: I'm sorry, 7 and 9?
MR. STODDARD: 7 through 9.
MR. GRUEN: 7 through 9.
BY MR. STODDARD:
Q Starting with page 7. This identifies "A root cause for the SS-25 incident was the lack of detailed follow-up investigation, failure analyses, or RCA of casing leaks, parted casings, or other failure events in the field in the past."
Do you see that?
A Yes.
Q "There have been over 60 casing leaks at Aliso Canyon before the SS-25 incident, but no failure investigations were ever conducted."
A Yes.
Q Do you contend that a root cause analysis should have been performed for all 60 casing leaks?
A Well, I would say that it would not be possible to do a root cause analysis in the manner that Blade did because you would have to take the well out of service and pull all of the casing; so that wouldn't be practical.
On the other hand, I think there were things

that SoCalGas could have done to determine the cause of failures, not just that a failure occurred, which seems to be what was typically happening. They could have determined causes using available technologies, and they didn't --

As near as I know, as I can tell they did not, at least not until I saw some study in 2014 on I think it's Well FREW2 that actually went to determining the cause of the corrosion, but -- and maybe that one actually wouldn't be considered a root cause analysis. But certainly it was closer.

In most of the well files that I have looked at, I don't see any evidence of an effort to determine cause.

Q You mentioned tools that can be used while the well remains in service to determine cause?

A Yes.

Q Can you identify some of those tools?

A Oh, I think we did that in a data response. But there are tools that can be run into a well while it's killed temporarily in order to measure the thickness of the well casing or a tubing thickness. There are other kinds of logs that can be run that would give you a sense of erosion or conditions of the wells.

So I think you have to pick the right log technique and contractor and collect the data and see what you can find out about the well.

Q So had SoCalGas, after identifying a failure, run casing inspection logs, in your view that would have been sufficient for purposes of identifying cause in a failure investigation?

A No. I think once they had determined, say, that there was -- there were a number of failures, say, in the same area -- either depth of wells or across a geologic formation, like sand with water in it has corrosion in a number of wells exposed to that sand, maybe the casings are all, you know, not cemented. If there are similarities across the wells, then I think they should maybe take one of those wells out of service and do a more extensive study.

Q But the question related to a specific well failure in terms of what an investigation would be for a specific failure, so taking one in isolation.

MR. GRUEN: I note an objection for the record.

It is not Safety and Enforcement Division's role to identify the kinds of investigations that Southern California Gas Company should be doing on its own field. That is the role of the operator and

it's -- the --

This goes beyond -- generally speaking, this goes beyond the scope of the testimony to ask questions prompting your witness, Ms. Felts, to identify how SoCalGas should be investigating its field.

So she can answer the question, but we're noting the objection for the record and -- on this question and others to which SoCalGas asks how it should be investigating its fields, including leaks in this one.

MR. STODDARD: Noted.

Q So to repeat my question, for purposes of a specific casing leak --

So earlier you talked about kind of a more regional type of potential investigation. I'm focusing in on what would have been adequate investigation for a particular casing leak.

After a leak is identified or there is a condition or a failure, had SoCalGas run a casing inspection log after killing the well, would that have been sufficient for purposes of identifying the cause?

A Probably not. There is probably going to have to be some additional information, but I can't

tell you exactly what it would be. And I would guess that if it were my well, and I wanted to find out the cause, I would probably call Halliburton or one of their competitors and say "What is your latest technology? How can we figure out what the cause of this failure is?" And they would be happy to charge me a lot of money and come tell me how to do that.

Q But you wouldn't kill the well, cut the casing and do a full-blown RCA?

A Well, it depends. Because I think actually SoCalGas did kill wells and look at casing in some instances. I'm not sure that they generated any reports that said what caused the failure in the well.

But if you have a low-producing well, it's not useful in the management of the field anymore and it's in a location -- it failed and it's in a location where it would provide useful information, there might be a good reason to take it out of service completely and remove some casing to find out what caused the problem. Because it could provide vital information for the rest of your wells that are operating well right now but might not be later.

It's an engineering decision that would have to be made by SoCalGas's reservoir engineers.

Q But to restate the point that you made earlier, an RCA for each and every failure would not be practical, correct?

A An RCA, to the extent that Blade did this one for SS-25, is not practical. It's not field practical for an operating field.

Q Okay. Direct you to page 3, 4, 5 and 6. This is the "Table 1: Summary of Violations," and this is in Exhibit 1-7.

A Okay.

Q Do you see the columns in this table titled "Begin Date" and "End Date"?

A Yes.

Q Did you validate the begin date and end date for each of these categories of violation?

A No. I can tell you right off the bat that I just resist doing the violation calculation; so I usually say to the PUC "Unless you need my help figuring out a start and end date, go ahead and fill it in."

Q So then you don't ask factual questions to assess the reasonableness of the start dates and end dates?

A Well, I'll look at them. For instance, if I saw that a date was completely wrong based on the

data that I had reviewed, then I would say something.

Q Based on the data that you've reviewed.

But you wouldn't ask for information to support specifically the alleged begin date and end date -- and take, for example, Violation Number 84?

A Okay, let's look at 84.

Q Page 4.

A Okay. Okay. And so this one they --

I know they started the date at the date of the memo in 1988 that said, gee, we should look at these wells and assess them for corrosion because of exposure to groundwater; so that started it in 1988. And the end date was the date that the Well SS-25 blew.

Q And for purposes of Violation Number 76 --

A 76.

This would be a date that was established by someone at the PUC having to do with some finding about inability to collect recovery; so I'm not familiar with that, with that date. And the end date, again, is the date that the well blew.

So I'm guessing that someone needed money from the Commission to support a program and delayed some action for that period of time.

Q So you're guessing.

But you don't know the particular facts to support that begin date?

A I don't know the underlying purpose of selecting 12-31-2009.

MR. GRUEN: I'm going to just ask for purposes of this line to reference where in the testimony we're talking to.

There is a testimony section that we're in that this is just the table summarizing violations; so if there is a specific line of questioning about the actual testimony that this refers to, I ask that the witness be directed to that portion of testimony.

MR. STODDARD: You didn't include page numbers here; so the witness is free to reference whatever she needs to reference in this document.

She said she reviewed it in advance of today's deposition. This is --

THE WITNESS: It says II.B, II.C, if I can find it.

MR. STODDARD: Yeah.

THE WITNESS: Looks like it's page 17.

Okay. So this is based on a James Mansdorfer recommendation that they start a Storage Integrity Management Program, but apparently it didn't start -- maybe it didn't start at all, but was

recommended in 2009.

So the start date of the violation was 2009. I'm assuming they picked the last day of the year to start the violation.

BY MR. STODDARD:

Q And why is that your assumption?

A It would be the most conservative choice in 2009. Any other day within 2009 would result in a higher penalty.

Q And you don't know Mr. Mansdorfer, correct, you stated earlier?

A No.

Q And you haven't spoken to him, correct?

A No. I read his interview.

Q You read his EUO?

A Yes.

Q Did you review this --

Did you review the documents aside from --

This is his EUO transcript here that is cited.

Did you speak with anyone else about Mr. Mansdorfer's EUO transcript with respect to this issue aside from Mr. Gruen?

A No. I believe he produced some documents, or maybe SoCalGas produced some documents by him that

I reviewed.

Q That are related to this issue?

A Yes.

Q Turning back to page 3. Again, trying to understand the factual basis for begin date and end date.

Violation Number 3, which is referenced at Testimony Section Number II.B.1.a.

A This is probably about page 16, I would guess. Okay. Okay.

Q Did you find the relevant section?

A Yes.

THE VIDEOGRAPHER: You lost your microphone.

THE WITNESS: I lost it again?

Okay. Is that better?

Okay, number 3. This is --

It says "No investigation on one of four parted well casings."

I had it, I lost it. Okay.

Okay. The violation extends from the Blade report. This has to do with a well. The casing was parted or found to be parted in 1969.

You see the page is number 7?

BY MR. STODDARD:

Q And the basis for that start date?

A That's the date of the first -- the earliest well casing report of a failed well casing in the SoCalGas well records as it was reported to Blade.

So Blade had a history of well casing failures, and that was the earliest one that was reported. And so that date was 1969, not 12-31-1969, but, again, the conservative date would be the last day of that year.

Q Would it be relevant to your testimony on this violation if SoCalGas did not own or control the field at that time?

A I considered that. And it's relevant, but it's not -- not necessarily decisive because SoCalGas was in the process of acquiring -- acquiring the field before 1973, which I think was maybe the operational date. They probably had an application in to the PUC for money to renovate the field.

In order to estimate those costs, they would have to have information about the wells and what they would have to do to them; so I'm guessing -- and I'm only guessing because I don't have records yet, but I would say it's likely that SoCalGas was aware of this problem with this well.

Q So the start date of the violation dates to SoCalGas's knowledge of when the violation -- when

the failure occurred?

A That's how it was set out in this testimony.

Q If SoCalGas did not have control of the field at that time, would you agree that SoCalGas could not have completed a failure investigation on that well at that time?

A I don't know how much control they had over doing investigations into wells that they were about to purchase. I don't have enough knowledge to answer that one way or the other.

Q Assume for the sake of argument, hypothetically speaking, that SoCalGas didn't have control sufficient to conduct an investigation or direct any other operational actions at the field prior to acquisition, would that be relevant to your testimony on this violation?

A I think it might --

Yes, it would be relevant. It would also be relevant to know whether they requested any failure analysis from the prior owner Tidewater.

Q Isn't it likely, Ms. Felts, that SoCalGas didn't possess the well files as of 1969 if they didn't own or control the field?

MR. GRUEN: Objection. Calls for speculation.

She can answer if she knows.

THE WITNESS: They were in the process of acquiring this field for a number of years; so I would guess, again, that some documents had to have exchanged hands, or there was some viewing of documents. I can't imagine SoCalGas bought all of these wells with no knowledge.

BY MR. STODDARD:

Q But to confirm a begin date for this violation is based on your assumption that SoCalGas would have had some form of access to both records and the ability to direct their predecessor in interest to conduct an investigation prior to acquisition?

A The begin date was originally just established on the fact that the parted casing on this well occurred in 1969; so you can argue it however you want to argue it.

Q Well, you said you considered the point that I'm asking --

A Yes.

Q -- which is SoCalGas's date of acquisition?

A And I explained that I think SoCalGas probably had access to information about this well, and may have been able to determine what the cause of this parted casing was.

Q But you don't know, correct?
A That's correct. I don't know anything that SoCalGas doesn't tell me.
Q And you're not aware of any records indicating that that's the case, correct?
A The -- the date, I believe came from Division of Oil and Gas records. But as far as a failure analysis, there is none in the record that I'm aware of.
Q My question was are you aware of any documents or other evidence that SoCalGas had the ability to perform a casing -- a failure investigation at that well prior to acquisition of the field?
A I don't currently have that information.
Q Okay. Thank you.
Referring back to pages 8 and 9 at the top of page 8, do you see there where it says --
And actually you have to turn back, I'm sorry, to the very end of page 7.
-- "Blade reviewed 124 gas storage wells and identified 63 casing leaks, 29 tight spots, 4 parted casings, and 3 other types of failures."
Do you see that?
A Yes.

Q And then your testimony discusses those.

And then in the bulleted section below it asserts specific violations "for failure to investigate the blowout from Frew-3 spanning from December 31, 1984" to October 23, 2015, the date of the incident.

And then a second violation for the failure to investigate the blowout at FF-34A, four violations spanning from 1969 to 1994 related to parted -- failure to investigate parted casings, and then 60 leaks -- or I'm sorry, 54 violations for failure to investigate an additional 54 leaks.

Do you see that?

A Yes.

Q You indicated earlier that prior to service of your testimony you reviewed well records related to SS-25, SS-25A and SS-25B, correct?

A Yes.

Q And in the course of that review, you found temperature logs based on which you disagreed with Blade's conclusion regarding a lack of anomalies in the temperature logs at SS-25; is that correct?

A Yes.

Q For these leaks that are listed here and for the alleged failure to investigate for each, how many

of these well files did you review?

A At the time I was relying entirely on Blade for the counts, and I -- I am not sure, but I believe Blade was relying on Division of Oil and Gas records.

Q And that's also what your belief was for purposes of the temperature log you disagreed with, correct?

Or, rather, their conclusions regarding the lack of anomalies in the temperature log, it was also your belief that they were relying on DOGGR records for that, correct?

A And did not have access to the well logs, yes.

Q Yeah.

So were you satisfied that if they were relying --

In your view or belief they were relying on DOGGR records for purposes of this analysis, what gave you confidence that this was accurate?

A Well, DOGGR records that they were reviewing were actually well histories that are reported by SoCalGas.

So if SoCalGas reported a leak, I'm guessing there was a leak. I don't think there would be any advantage for SoCalGas to report a leak on the well

history if there wasn't one.

So they were just counting up casing failures and leaks, and they were looking for cause -- a determination of the cause of those and not finding that.

Now, I don't know what other access -- without looking at what SoCalGas's responses were to Blade's data requests, I don't know what other information they rely on to do that. But I hope to find out. But I haven't seen it yet.

Q If they were relying on DOGGR records, given your experience or your views on the lack of information there related to the temperature log, isn't it possible that they were still miscounting the number of leaks here?

A I don't see any way they could be miscounting the leaks. Could be undercounting them.

Q That's miscounting, correct?

A Yes, but it would be to the advantage of SoCalGas if they undercounted.

Q Does the characterization of the type of leak matter for purposes of violations related to failure to investigate?

A A leak is a leak, so I would say no, although --

You could have, for instance, five holes in the same location, in a very small area in a pipe and call it one leak, whereas I think within the industry, a leak is just a failure of the casing.

So, you know, how you count the leak may determine on how detailed you get in terms of how many holes are in a piece of pipe.

Generally, I think SoCalGas would probably report just a failure. If they had a failure and they had to patch it, they wouldn't count the number of holes that were under the patch. It would be one leak.

Q What about leaks that aren't in the body of the casing, is that relevant in your view?

A Leaks, for instance?

Q For instance, a shoe leak.

A Well, a shoe leak is important because you lose gas through it.

So if you're in the business of storing gas for your own business or for someone else, you don't want to be losing it into a part of a reservoir where you can't get it back.

Q And what about leaks, "Leaks" that are the result of faulty -- something like a valve that may not be operating properly, would that in your view be

a leak, a mechanical piece of the well?

A What are you talking about, a release of the gas into the well or external to the well?

Q A leak that would show up on a temperature log.

A I don't know how that would show up on a temperature log.

Q All right. Let me ask it differently.

Are you aware of any instances where an operator might deliberately put holes in a tubular or casing?

A You would perforate a casing purposely, yes. That would be so you can either inject or extract the gas from that level of the reservoir.

Q Would it ever be done for purposes of cementing?

A Yes.

Q And are those holes on occasion plugged with cement?

A Sometimes.

Q And if one of those holes were to be leaking gas, in your view, is that a leak that requires investigation or simply repair?

A I would suppose if they understood exactly what was going on that they would just patch it, and

there would be no purpose to investigate it because the recurrence is not likely to occur unless, say, something was dissolving the cement.

Q I'm going to direct you to page 13 of your testimony.

A Okay.

Q You'll see here this relates to the heading "SoCalGas Did Not Implement a Risk Assessment Program Or Wellbore Integrity Management Plan on the Aliso Canyon Storage Facility Prior to October 23, 2015," and if you turn to page 16, which is the end of this section under this heading, it states "SoCalGas's failure to implement any form of risk assessment program or wellbore integrity management plan on the Aliso Canyon storage facility prior to October 23, 2015, and beginning 2009 and continuing through the date of the incident, constitutes a separate violation of Section 451 for each day it failed to implement the risk assessment program."

Do you see that?

A Yes.

Q And then I'm going to refer to the next two sections, section b) also relates to SoCalGas's failure to implement a risk assessment program or wellbore integrity management plan prior to the date

of the leak.

Do you see that?

A Yes.

Q And resulted in the failure to detect corrosion on the well at the 7-inch casing prior to October 23, 2015.

Prior to October 23, 2015 would include 2009, would it not?

A Yes.

Q Aren't these two violations really the same thing, which is SoCalGas's alleged failure to implement a risk assessment program or wellbore integrity management plan?

MR. GRUEN: Objection. Calls for legal conclusion.

MR. STODDARD: All right. I'll ask it in a different way.

Q The underlying conduct, which is a factual question, that serves as the basis for these violations is the same, is it not?

A Yes.

Q And that's also true for the next Section c) "SoCalGas Did Not Start a Storage Integrity Management Program in 2009, Even Though It Was Recommended by Its Storage Engineer Manager At

That Time Because They Could Not Yet Collect It in Rates," is that correct?

A The start date and underlying issue of storage, no storage integrity management program is the same.

Second half of it is different, and it has to do with a decision they made -- SoCalGas apparently made related to not being able to collect and rate the money to start the program. Slightly different in my mind.

Q But the underlying conduct related to the violation is the failure to initiate an integrity management program, correct?

A That's what it's linked to, yes.

Q Okay. Thank you.

And for all three of these sections on pages 13, Section a), 16 Section B), and 17 Section C) the basis for the statutory violation legally is Section 451, correct?

A Yes.

Q Ms. Felts, do you know which agencies are involved with regulation of gas storage operations in the state of California?

A Department of Oil and Gas would be the primary agency. I would expect the Energy Commission

might have some interest as a secondary.

The Public Utilities Commission, because they're operated by utilities, the Air Board probably has an interest because of air emissions, and the possibly local water boards because of potential water discharge from separators and that sort of thing on the surface. And probably also for groundwater contamination.

Q And at the federal level, are you aware?

A I would think that California would probably have most of the authority, although there might be some authority under PHMSA for some of the pipelines that are connected to the gas storage.

Q Are you aware of the memoranda of understanding related to the Aliso Canyon investigation between DOGGR and the CPUC?

A I have not seen it.

Q You have not seen it. Okay.

Which agency do you believe has primary jurisdiction over down hole gas storage and gas storage wells?

A Department of Oil and Gas.

Q I want to refer back to your testimony. This again is Exhibit 1-7 page 18. Paragraph -- or I'm sorry, header 3, "SoCalGas did not have a dual

mechanical barrier system in the wellbore of SS-25, instead leaving the 7-inch production casing as the primary barrier to the gas."

Do you see that?

A Yes.

Q Can you explain exactly what is meant by a "dual mechanical barrier" here?

A The idea would be to have it designed so that you have tubing going down the middle of it and then an external casing finished through your top casing so that your external casing is separate -- serves as a barrier. But in this case, because they were producing and injecting through both the casing and the tubing, then you lose the protection you don't have in, like, a second wall outside of your production casing.

So in this case Blade is saying that they didn't have that extra protection; so when the 7-inch casing failed, there was nothing outside of it to contain the gas. It was a true failure.

Q Are you familiar with the usage of dual mechanical barrier at other gas storage fields?

A I actually don't know what the -- I don't know what technology is used in the wells in other storage fields around the United States. I haven't

looked into that.

Q Okay.

A I'm assuming Blade knows.

Q I'm going to refer you now to page 19. And there is an embedded quote. And this discusses SSSVs.

Do you see that?

This -- I'm sorry, this is the embedded quote at the bottom of page 19. "Also as noted by SoCalGas's Storage Engineering Manager, James Mansdorfer."

A Okay.

Q And the discussion of subsurface safety valves goes on to page 20.

A Yes.

Q Can you explain how subsurface safety valves relate to the lack of a dual mechanical barrier?

A Apparently they did not at the time have SSV that would accommodate injection and production out of both tubing and the casing. Though they installed some, I think they installed three different ones in SS-25 very early on and ended up removing them or removing the guts of the valves because they couldn't get them to work.

And then in later -- I saw maybe this quote

is from that note -- memo from James Mansdorfer that he thought there was a new technology out there that they could probably install in some of the wells that would accommodate that sort of production and injection.

Q I don't believe that exactly answered my question.

I am wondering how SSSVs relate to the dual mechanical barrier issue or whether they do?

A I think I answered that. I don't know why --

Q Rather than I -- if you could restate your response. I'm not --

I can see the history that is accounted here, but operationally do they -- does inclusion of an SSSV provide a dual mechanical barrier?

A No.

Q Okay. If a field is converted to tubing flow only, those wells would have a dual mechanical barrier, correct?

A Yes.

Q Do you know what the diameter of -- the range of diameters for tubing is relative to a production casing in a gas storage operation roughly?

A Do you want a range of the size of tubing?

Q Let me restate the question.

Tubing is significantly narrower than casing, correct?

A In this case, it's 3-7/8 and the casing outside of it is 7-inch.

Q So converting a field like Aliso Canyon to tubing outflow only would have a significant impact on deliverability, correct?

A Not necessarily.

Q How so?

A I think it --

Because they can replace the tubing with a larger tubing. And the efficiency of a well depends on more things than just the size of the tubing; so it depends on the permeability of the reservoirs they're producing out of, how much gas they can pack in at what pressure and how fast that will flow back.

There could be other factors in the design of the well and the well head that would allow for a more efficient production; so I don't think you can just pin it on the size of the -- the initial size of the tubing.

Q "The initial size of the tubing."

So let me ask another question and see if this helps clarify it.

But taking an existing field with the parameters you noted as factors in deliverability, if you take an existing field, holding all of those parameters constant, and you put tubing into an -- existing wells that presently has 7-inch casing, would that reduce deliverability of that field?

A If I put a new tubing in it?

Q Uh-huh.

A At what size?

Q You indicated big tubing.

A Well, you can't go any bigger than the 7-inch casing. But I think that they have tubing that is in the 3- to 5-inch size. And, I mean, here again, you would have to ask a drilling company to spec that out for you to make sure that it would work.

Q So let's say 3-inch.

A Okay.

Q Would that reduce deliverability to the field?

A Not if you're going from a 2-7/8 to a 3-inch.

Q If you're putting -- I'm sorry, if you're putting new tubing into a field that presently doesn't operate as a tubing flow only field, so if

you're presently operating it as a dual flow gas storage field, and you convert it to tubing flow only and you're extracting it through a 3-inch tube, would that reduce deliverability to the field?

A If you hold everything constant, and all you're doing is you're going to produce out of the tubing and not out of the casing, then you're going to have a reduced flow.

Does that answer it?

Q Yes.

A You don't have to replace the tubing.

No matter what you do, if you're not producing out of the casing and you keep the casing the same size, you're still going to have reduced flow, and holding everything else constant, if you don't do anything else to improve efficiency.

Q Okay. Turning to page 23, middle of the third paragraph down where it states "It is not possible to determine what an inspection of the SS-25 casing would have shown in 1988, but it is possible that the corrosion was present and detectable, and steps could have been taken to avoid the leak in 2015."

Do you see that?

A Yes.

Q And the next sentence says "SoCalGas logged some of the 13 remaining wells starting in 2007, resulting in a gap from 1990 to 2007 when no inspection logs were run in the 20 wells, according to the available well records."

Do you see that?

A Yes.

Q And this relates to the 20 wells that were on the 1988 memo, correct?

A Yes.

Q Did you evaluate the logs of any of the 13 remaining wells that were logged starting in 2007 referenced in that second sentence?

A Not before this testimony was published.

Q Have you done so since?

A Some of them, yes.

Q And what did they show you?

A I think that's probably part of my future testimony, so --

MR. GRUEN: We'll note the objection for the record.

MR. STODDARD: And the objection is?

MR. GRUEN: The objection is that this is protected under attorney-client and attorney work product privilege to the extent that it covers work

that is going to be -- testimony that is going to be produced in the future. Excuse me.

BY MR. STODDARD:

Q Please turn to page 27, middle paragraph.

Do you see the sentence that says "Further, since no formal risk assessment was conducted regarding well integrity, wall thickness inspection was not identified as a monitoring technique"?

A Yes.

Q Do you contend that SoCalGas was unaware of casing inspection tools?

A No.

Q Can you explain your statement there what you meant by "was not identified"?

A I think this statement comes from Blade, and basically I -- what I think I am saying there is that since there wasn't a formal risk assessment conducted, it wasn't possible to -- to say that wall thickness inspection was performed.

So, in other words, if you had a risk assessment, a formal risk assessment, it would have the results of this monitoring technique. It would be pretty common in one of the first things you would do in a formal risk assessment. But without a risk assessment to look at, I can't conclude that the tool

was used.

Q And you say you think that's what you're saying, but this is based entirely on the Blade report, correct?

A Well, it came out of the Blade report, yes.

Q So this is what Blade is saying?

A Yes.

Q Turn to page 72, please.

A Okay.

Q Do you see where it states the "Well file for SS-25A contains information" --

In the second paragraph?

A Yes.

Q -- "that might have been useful to SoCalGas and its contractor in calculating the appropriate requirements to kill the well in October 2015 and thereafter."

A Yes.

Q What information were you referring to there?

A I believe it's attached as an exhibit. It was --

I'm just remembering that it's a Halliburton report on the reservoir characteristics that were logged by Halliburton. I'm not sure what the date

was. But it included permeability readings for the full depth of the well.

Q So maybe it would be helpful just to read the rest of the paragraph.

"For example, the Permeability of the Aliso reservoir is in a record in that file."

A Yes.

Q And can you explain how permeability was a factor for purposes of the well kill?

A When you look at the Blade model results, Blade had to assume a permeability. They didn't have the data; so the data was also not in the SS-25 well file, it was in SS-25A.

So if someone went to look for permeability, which would have been useful in their calculations or models, assuming that any of the contractors like Boots & Coots were actually doing calculations, say, on a calculator or computer that we don't know about, but let's say that they were, they would need that piece of data.

And so there is a statement in the Blade report that says if you change the permeability in the model that they were running, you got different results. And so I went looking for the permeability data to see if it was available to Boots & Coots.

And for SS-25, it was not in that file, but it was in the SS-25A file. And since they're right next to each other, it would have been relevant.

Q And you said that that document was not available to Blade, correct?

A Not available -- apparently not available. They --

Q To Blade?

A Yes.

Q Yeah.

Boots & Coots is the operator that performed the well kill, correct?

A Yes.

Q Earlier you indicated you don't have any -- any experience with well-control operations, correct?

A Not directly.

Q So then you're not aware of whether permeability of the reservoir is something that a well-control operator would typically consult or reference or consider?

A I just went by what was reported in the Blade report that they needed in order to do their calculations.

So this was part of their -- part of their calculations, and it was a factor that they didn't

have and had to make some assumptions about.

Q Okay. Let's move on to the next sentence in the SS-25A well file.

There is an example of a well kill that failed due to the use of an incorrect bottom hole pressure.

A Yes.

Q This is another record that you contend might have been useful to SoCalGas and its contractor in calculating the appropriate requirements to kill the well, correct?

A Yes.

Q Do you believe an incorrect bottom hole pressure here was the reason that the well-kill operation failed?

A Yes.

Q And what is your basis for that belief?

A Well, again, the models that Blade ran consistently showed that they weren't weighting the material properly. It wasn't heavy enough to overcome the reservoir pressure, and they actually recalculated based on old data that was provided or acquired from SoCalGas and came up with a higher bottom hole pressure, Blade did.

Q And you believe this is the case for kills 2

through 6?

A Yes.

Q The next sentence is "Other examples include the shallow leak on SS-25A and the formation of hydrates in an instance of leak repair, which may have been useful information."

Do you contend that Boots & Coots did not understand how to clear the hydrate that formed -- or according to Blade the hydrate that formed at SS-25A -- or, I'm sorry, at SS-25 during leak response?

A No.

Q Do you contend that Boots & Coots was unaware that there were hydrates in the well during the second well-kill attempt?

A At the time --

Q Let me restate that. I'm sorry.

Do you contend that Boots & Coots was unaware of the potential for hydrates after the first well-kill attempt?

A No. I think they were always aware of the potential.

Q How specifically would the document related to formation of hydrates in the instance of leak repair been useful to SoCalGas or Boots & Coots with

respect to the leak response?

A Well, without looking at the reference documents, I can't say specifically. But as I recall just sitting here, I believe there was a shallow leak that might have been informative as to the depth of the leak, and I don't remember the issue having to do with the hydrates just offhand.

Q And to reiterate, based on these, the footnote citations, this is based on your independent review of the well file and not the Blade report, correct?

A That's correct.

Q And Blade did not raise these concerns regarding these records in connection with the well kill, correct, to your knowledge?

A No. Let me correct that.

They raised the issue of not knowing the permeability because that was in their report.

Q Blade not knowing the permeability?

A Yes, and not having -- not having access to that data; so they made an assumption about what the permeability was. I'm not sure what that was based on. But they did provide additional calculations in their report with different permeabilities and said if it was this permeability, this would have

happened. So they were clearly considering a range.

Q But Blade did not raise the document-related issues related to the other items -- the other examples that you provide in this paragraph in connection with the well-kill operation, correct?

A It's not in their report.

(Discussion off the record.)

MR. STODDARD: I guess can we go off the record for a moment, please.

THE VIDEOGRAPHER: Just a moment, please.

We are off the record at 5:59 p.m.

MR. STODDARD: This is the end of disk number four, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

(Off the record.)

THE VIDEOGRAPHER: This is the beginning of disk number five, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are on the record at 6:22 p.m.

BY MR. STODDARD:

Q Ms. Felts, picking back up again with Exhibit 1-7, I'm going to direct you to page 44 and 45.

The heading for this section is titled, starting with lower case b) "SoCalGas Did Not Assess

the Relationship Between Groundwater In and Around the SS-25 Well Site, and The Surface Casing Corrosion of That Well."

Do you see that?

A Yes.

Q And on page 45 it states "SoCalGas's failure to assess the relationship between groundwater in and around the SS-25 wellsite and the surface casing corrosion of that well on SS-25 constitute a violation of Section 451."

Do you see that?

A Yes.

Q What is your understanding of practices at other gas storage fields relating to the assessment of the relationship between groundwater and well casings?

A Anybody who drills a well has to at least have a preliminary idea of where the groundwater is; so that starts because you case down to the bottom of the groundwater, fresh groundwater.

Q And by "case down," you mean set your surface casing?

A Yes.

And so after that I would not know exactly what the practices are at other gas facilities.

Q Okay. Thank you.

In terms of how to assess the relationship, do you know how Blade assessed it for purposes of their RCA investigation?

A I think they drilled a couple of wells.

Q And do you believe that that would be required in the proximity of each well at Aliso Canyon to understand the relationship between groundwater and the wells?

MR. GRUEN: Again, I'm going to note the objection that this is calling for SED to recommend investigations to SoCalGas as to how to investigate its field, which is beyond the scope of SED's purview.

But she can answer.

MR. STODDARD: Actually, let me restate the question.

Q Ms. Felts, what is your understanding regarding how to assess the relationship of groundwater in a storage field relative to the casings in a gas well?

A There are options. You might do them all. One is the simple option of being very familiar with the geology after drilling wells and/or looking at the geology reports from the drilling and then

understanding where sands, sand lenses outcrop and water would fall on the sand at the outcrop and run down the -- that part, that part of the strata. And so where it would impact each well, you would know approximately the thickness of that sand, and that would be the exposure to that amount of water; so that's a geologic approach that requires no drilling.

In addition to -- or alternatively, you could set monitoring wells in those sands that are cased to and then open to those sands so that you could monitor the depth of groundwater at any point in the area. You would have to --

You wouldn't set a well next to every well, but you would set a monitoring well in an appropriate place where your geologist thinks that there might be some variation in the depth of water in that lens, that sand lens.

There could be other ways to do some sort of monitoring that might hit in between those two. You might have historical water production when you were drilling a well like a newer well and be able to report that, and then connect that to a sand lens and have the knowledge in the record that there is water in a -- at a certain depth in one well that might carry over to another one because of the geology.

Q Okay. And circling back on your earlier statement, it would be necessary to have an understanding of groundwater depths for purposes of setting the surface casing, correct?

A Yes.

Q Okay. Also on page 45, you see the discussion of cathodic protection, where it states "Cathodic protection systems are commonly used to protect pipelines from corrosion and are sometimes used on well surface casing strings"?

A Yes.

Q What is your understanding of how cathodic protection works?

A Do you want a technical explanation or just something generic?

Q Your choice.

A Well, there is --

I guess you would look for a location that would be defined on an anode on a well casing or a pipeline, and a cathode location somewhere else. And the flow of electricity from one to the other can result in the removal of metal, usually iron, but also iron component of steel, from an unprotected pipeline.

So then when you do cathodic protection, you

basically reverse the polarity on that flow, on that electrical flow.

Q Also on page 45 you state "Cathodic protection would have provided corrosion protection to the 11 3/4-inch casing, but would not have protected the 7 inch casing inside the 11 3/4 inch casing."

Is that correct?

A Yes.

Q Why is it important in the context of your testimony and alleged violations that cathodic protection be applied to a surface casing if it would not have protected the 7-inch casing?

A Well, so the purpose of providing it to the surface casing was because that was what is exposed to water so more likely to corrode.

And what was the other half of your question?

Q That's fine. I can ask another question.

Did corrosion to the surface casing in your view cause the failure in the 7-inch production casing at SS-25?

A I'd have to go back and look at the details of the Blade report, but my understanding is that there was water entering the -- water entering the

casing at some point the surface casing or below at the 7-inch casing that was causing external corrosion; so I'd have to look at the drawing and tell you whether I could answer that specific question correctly.

Q Water also could have been coming up from under, correct?

A Coming up from under --

Q Under the shoe?

Could have been entering --

A Could have been, yes. It could actually just be produced with the gas. There is no telling how you can get water into a well.

Q So you're not contending that corrosion of the surface casing was the point of entry for water that caused the corrosion at SS-25 production casing?

A I am not. But Blade seems to think that that was contributing to it because they found the MIC in the -- as a cause of the corrosion, which would require some moisture; so I think they tied it to surface moisture or shallow moisture.

Q But you're not sure?

A I'd have to go back and look at it. It's been a while since I read that section.

Q Do you have prior experience with cathodic

protection?

A Well, I reviewed a lot of records with PG&E on cathodic protection. And before that we had cathodic protection on pipes at the oil refinery and at the chemical refinery where I worked.

And other than that, as a consultant, I think the only places I might have run into it is if there was cathodic protection on piping or underground storage tank systems that had to be disabled while we worked on them is all. I didn't have to operate it or analyze it.

Q Okay. So you reviewed records related to it; you didn't personally apply cathodic protection?

A No.

Q Or advise regarding installation of cathodic protection?

A I would call an expert in cathodic protection.

Q And in the cases you mentioned before, they were all pipeline cases; is that correct?

A Maybe underground storage tanks. I'm not sure.

Q What sort of underground storage tanks?

A It would be petroleum.

Q Are there any --

Is there any difference that you're aware of applying cathodic protection to above-ground pipes versus underground storage wells?

A I think it's a little bit more complicated for underground wells because they're vertical, and because you might have, like, SS-25 and 25A and 25B, co-located wells that will interfere if you don't design the system correctly.

Q How --

A But it's not impossible. It's just that it's a different application of cathodic protection.

Q Can you explain how you avoid interference with neighboring wells through system design?

A No. But I can look it up for you, and I can call an expert. And I think I provided some reference documents that included that information in response to DR 3.

DR 3? Your DR 3.

Q Data Response 3?

A Yes.

Q And those documents --

Did you prepare Data Response 3?

A Yes.

Q And you collected the documents --

A Yes.

Q -- for purposes of Data Response 3?
A Yes.
Q Do you recall when you collected those documents?
A After we received Data Request 3, whenever that was.
Q Is it your opinion that cathodic protection should be applied at the surface casings of all gas storage wells?
A I think it should be applied where there is a threat of corrosion. There may be instances where there is not.
Q There may be instances where there is no threat of corrosion in a gas storage well in the ground?
A Well, yes. I think that's possible.
Q Are you aware of any specific examples of that?
A I think actually in the Aliso field there might be some areas that they feel like would not require it, and then there is other areas where they think it's necessary.
Q But if there is a threat of corrosion, which would include, based on what you said previously, I'm guessing presence of water generally in the

environment, geology perhaps, you would believe cathodic protection is appropriate if there is a risk of corrosion?

A It certainly is a technology that should be investigated. There is other things you can do. You can put chemicals down the well. You can coat the casing if you happen to be drilling the well now and installing it. There --

You know, I think there are other things that you could do if you did not want to apply cathodic protection. But I do think that cathodic protection is the first thing that most engineers would look at.

Q In terms of putting chemicals down the well, what sort of chemicals are you referring to there?

A Well, typically it would be something like biocide, something to kill the MIC.

Q And that would generally protect against corrosion of the internal diameter of the casing, correct?

A Yes, won't help you with the external.

Q And in terms of the specially-treated casings, that's --

A External.

Q That's external --

A It could be external and internal.
Q But again for newly-drilled wells --
A Well, yeah, if your casing is already --
Q -- not for existing wells?
A -- in ground and cemented, you're not going to be able to do it.
Q Thank you.
Is it your opinion that SoCalGas should have cemented the production casing at SS-25 all the way to the surface?
MR. GRUEN: Objection. Just vague as to time.
BY MR. STODDARD:
Q Is it your contention that SoCalGas should have cemented the surface casing at SS-25 all the way to surface sometime after it acquired the field?
A It would have been a prudent thing to do.
Q For existing wells that are in gas storage fields in California that are not cemented to surface, do you believe that those wells should be cemented to surface to protect against the risk of corrosion?
A You mean should they be done -- should it be done now?
Q Should it be a retrofit?
A I think it's an economic assessment that

needs to be done there to determine what the risk is of leaving it as is versus cementing it and having the protection for the rest of the life of the well. And some of those wells are pretty old; maybe it's not cost effective. Maybe you're going to be shutting them down pretty soon anyway and replacing them.

Q So cost effectiveness of the measure would be relevant to the consideration of whether it should be done?

A I think so. But also risk assessment. If there is a risk of it blowing out, that could be part of your cost-effective calculation.

Q Would you contend that a failure to cement an existing well to surface would be a violation of 451?

A Probably depends on the specifics of the well.

Q Including cost effectiveness.

A Well, for a 451 violation, I think we would look at the risk primarily of there being a failure that would create a problem at the surface.

Q As well as feasibility of the operation?

A Feasibility would certainly be part of the equation.

Q Would assessment of risk include past success with addressing well failures and leaks?
A For example? What do you mean?
Q If an operator had -- historically had success with identifying leaks and repairing them as they arose, would that be relevant to your consideration as to whether it would be a violation of 451 if they chose not to cement the casing to surface?
A So we're still talking about casing, the surface casing?
Q Sure. Uh-huh. No, I'm sorry, the cementing.
A "Cementing"?
Q Yeah.
A So if they had a good record in the past of fixing leaks in surface casing that was not cemented, would that be relevant to the decision not to cement?
Q Let me restate this.
A Okay.
Q And let's limit this to the cementing issue.
A Okay.
Q You said that --
We talked about how cost effectiveness would be one factor in considering whether or not to cement

to surface.

You said risk assessment would be another factor?

A Yes.

Q My question is whether part of that risk assessment would include past success with addressing and fixing leaks as they arose.

A I wouldn't give that a lot of weight unless in the process there had been determination of what the cause of those leaks were; so you could accurately forecast whether or not the problem was going to continue with other wells.

So if all they're doing is patching things to keep -- and well after well is failing for the same reason, but they don't know the reason that it's failing, then you would know things are going to continue to fail. And in that instance, the fact that they're successful at plugging holes in wells doesn't really help with a risk assessment, because the risk continues for other wells. They're going to continue to leak if you don't know how to stop the cause of the leaks.

Q Is that true if the consequences of those leaks are not significant?

A Well, I suppose SoCalGas might be able to

categorize some leaks as not consequential or not important and others important. But I'm not aware of how they would do that.

You know, a failed well is a failed well, and you have to fix it. And if you don't want it to happen to the next well over, then you need to find out why it failed.

Q Speaking hypothetically and abstractly, frankly not even in the context of gas storage operations, would you agree that a risk assessment should include both the likelihood of a given event and the consequences of the event?

A That's a typical statement for pipeline risk assessments.

Q Okay. Moving on to page 47 of the same exhibit. This violation -- alleged violation is related to -- stated as "SoCalGas lacked a real-time continuous pressure monitoring system for well surveillance, which prevented an immediate identification of the SS-25 leak and an accurate estimation of the gas flow rate."

Are you familiar with what other gas storage operators do with respect to real-time pressure monitoring?

Let me restate that.

Are you familiar with what other gas storage operators did as of October 23, 2015 with respect to real-time pressure monitoring?

A No. I did not look into that. This is based on the Blade report and what they determined.

Q What is your understanding of what SoCalGas would have done or could have done had they immediately identified the leak due to real-time pressure monitoring?

MR. GRUEN: I'm going to --

MR. STODDARD: I'm sorry, I'll restate that.

Q If SoCalGas had been able to immediately identify the leak because of a real-time pressure monitoring system, what do you contend SoCalGas could have done that would have helped mitigate the consequences of the incident?

MR. GRUEN: I'm going to note an objection to the extent this is calling for Ms. Felts to recommend fixes or recommend investigations.

Again, this is outside the purview of SED and it is -- so it's beyond the scope of what SED is called to do.

But Ms. Felts can answer the question.

THE WITNESS: Okay. Just a minute. Let me see what Blade said on this.

Okay. So on page 48 there is additional information about that.

BY MR. STODDARD:

Q Would you please read?

A In the third paragraph, "The lack of real-time pressure measurements prevented the immediate identification of the 7-inch casing failure."

I guess you might have to read the paragraph ahead of that to get the context.

"But constant monitoring of the tubing production casing and surface casing pressures will provide better insight into operational deviations in all wells."

So I think here the concept is that if you have real-time data, you would be able to see exactly what was going on in the well, and because they didn't have that, they were somewhat hampered in being able to detect a leak before it actually broke out to the surface and they started to smell it, which I think is the way they detected it.

So this is a plan, an idea of how SoCalGas could have been monitoring the system to see the -- see the leak in an operational data manner rather than just waiting until it leaks to the surface.

Q I understand how -- your response, I believe, describes how continuous real-time pressure monitoring would have enabled identification of the leak at an earlier time.

A Right.

Q What would that identification have enabled SoCalGas to do in response?

A Their response would probably still be to shut down the well and I'm guessing and to start a well-kill process. It's probably Blade's thought on this, and I think you would have to ask Blade, that an earlier detection might have prevented some of the damage from occurring and might have allowed the first -- the initial well kill to be successful. But here again, I think you should ask Blade that question, not me.

Q Well, it is your testimony; so I'm going to ask you.

How would shutting the well immediately have prevented further damage in your view?

A Well, this well was already leaking through the casing when they shut it down, whereas -- I mean, significantly leaking. If they had been able to detect a smaller leak first, they might have had a better outcome on their original well kill. That's

my read on it.

Q How much earlier do you think that would have needed to be? Are we talking minutes, hours, weeks?

A I would --

I don't know because I don't know how fast the problem within the well was occurring. But my understanding is that the real failure that caused -- caused the detection outside of the well on that day was fairly sudden.

I mean, the loss of gas at that -- in that amount was a result of a fairly sudden event within the well.

On the other hand, microbial corrosion and small leaks through holes is not sudden. And so it's possible they might have picked up a problem earlier, maybe even weeks earlier, through regular monitoring.

Q So a continuous real-time pressure monitoring system would have been useful in identifying development of a leak over a period of time?

A Right. Or a major leak. I think you would be -- you would be looking at a leak, but a major leak might be preventible.

Do you understand?

Q A major leak might be preventible if you catch it early?

A Yes.

Q As it's developing?

A You would catch a smaller leak earlier, right.

Q Okay. Separately the second part of the statement in paragraph 8 on page 47, the first is the immediate identification of the leak, which we discussed. The second, an accurate estimation of the gas flow rate.

Can you explain why continuous real-time pressure monitoring is necessary for accurate estimation of the flow rate?

A If they had detected the well, the problem earlier, they would have been able to shut in the well, avoid the catastrophic failure of the pipe casing, and then they might have had a better chance of being able to estimate the gas flow rate or would have had a better measure of gas flow at the time the well was shut in.

So what they did was they let the well fail for lack of monitoring, and once it failed and was blowing out, up the side of the casing, there wasn't a way to measure the gas flow rate.

Q So you don't believe that they could get accurate -- or that --

You are aware that there are pressure gauges on the well head and on the casing?

A Yes, but that was useless once the well blew out.

Q Why is that?

A Because the gas was coming up outside of the well. It wasn't coming up through those, past those instruments anymore.

Q And prior to the blowout?

A Well, prior to the blowout they had measurements of the flow in and out of the well through the piping and the instrumentation. After the blowout, that instrumentation wasn't useful.

Q So what would a continuous real-time pressure monitoring system have provided that they couldn't have collected prior to the blowout?

A The way I connect this is that the real-time monitoring system would have probably prevented the blowout because they would have detected the leak at a lesser amount and shut in the well; so they would have had their readings at that point in time. But if they shut in the well, they wouldn't have to use the readings. They would have the flow, but it's

kind of --

Q So it's more about the ability to shut in the well and prevent further development of a smaller leak into a bigger leak --

A Right.

Q -- than it is about the flow rate?

A I think so.

Q Okay. But you're not sure?

A Well, because that seems to be tacked onto there, and I don't know why, I would have to go back and look at it again to see how that developed.

Q I don't know either. I'm sorry, I interrupted you.

I mean for purposes of this violation, you would agree that you're relying heavily on the Blade report, correct?

A Yes.

Q Entirely on the Blade report?

A This one is from the Blade report, yes.

Q And maybe you don't fully understand what Blade was saying on this issue.

A I think the -- I think the caption here was refined from the Blade report, and so it looks to me like two issues are merged together here.

But since it's all one violation, I don't

know if it makes any difference if you drop out the accurate estimation of gas flow rate, it's still the same violation.

Q So you believe you understand and have accurately stated Blade's position with respect to preventing development of a leak over time by shutting in a well?

A I think the following -- the text that follows that heading -- the heading is a little weird, but the text that follows it I think accurately represents what Blade said.

Q Do you believe, Ms. Felts, that it's important or critical when you're asserting violations that you have a good understanding of the underlying facts related to and supporting those violations?

A Sure.

Q On page 50, it says in the middle paragraph, "Industry technology has evolved for real time pressure, temperature, flow, and vibration monitoring but, surprisingly, there were no significant differences in the monitoring plan from 1989."

Do you see that sentence?

A Yes.

Q How has industry technology evolved -- let

me restate that. I'm going to break these into separate questions.

How has industry technology evolved for real-time pressure monitoring?

A Well, I think over a period of time the accuracy and reliability of any instrumentation that might be used on a well has improved.

Q How has technology evolved for temperature monitoring?

A I would say not a lot. It's still pretty much the same log. There may be more accuracy in the feedback on the log. But basic technology is the same.

Q So then the statement you don't agree with?

A I don't not agree with it. I am just not aware of whatever Blade was aware of. It's footnoted to Blade's report, and apparently they have an opinion about that that you could ask them about.

Q Turning to page 51, Section C. "Additional Violations," Number 1 is "SoCalGas Knew That SS-25 Released Both Crude Oil and Natural Gas During the Aliso Canyon Natural Gas Storage Incident, But Did Not Disclose This Fact to the Los Angeles Department of Public Health."

Do you see that section?

A Yes.
Q You weren't personally involved in any discussions with DPH related to this issue, were you?
A No.
Q What did you do to get yourself comfortable with sponsoring your testimony on this issue?
A Originally my understanding was that the Department of Public Health was going to sponsor this section and would support it, and so I didn't do anything other than read it. But I do have a background in environmental technologies, environmental issues, and so I felt like I was pretty comfortable with supporting it.
Q But you didn't have personal knowledge relating to the Department of Public Health's specific dispute here with SoCalGas, correct?
A The only thing I had were the letters that went back and forth that were provided to me. I think they're attachments.
Q If you turn to page 52, do you see the last sentence of this section which says "These dates and the precise nature of this violation may be modified pending additional testimony from intervening parties to this proceeding with expertise in public health"?
A Yes.

Q Intervening parties based on your prior statement, I understand that intervening parties to this proceeding with expertise in public health was DPH?

A That was my understanding.

Q Were there other potential parties that you were aware of?

MR. GRUEN: Objection. Calls for speculation.

BY MR. STODDARD:

Q Were you aware of any other parties that were being actually -- no, I'm going to restate it.

Were you aware of any other parties that were considering intervening in this proceeding on this issue?

A As interveners.

Q The sentence says "These dates and the precise nature of this violation may be modified pending additional testimony from intervening parties to this proceeding with expertise in public health."

I'm asking whether "parties" there refers to anyone other than DPH?

A I don't know.

Q You're not aware of anyone else that would have been?

A I was not told of anyone else.

Q Okay. Did you draft this sentence?
A No.
Q And it's your understanding that there was an arrangement by which DPH would come and provide the supporting factual basis for this violation?
A Yes.
Q You indicated that you reviewed letters related to this violation; is that correct?
A There is at least one letter from DPH to SoCalGas and one from SoCalGas to DPH that I believe were attachments to this testimony that I read.
MR. STODDARD: I'm going to introduce Exhibit 1-31.
(Deposition Exhibit 1-31 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q You reviewed this letter?
A Yes.
Q And you considered SoCalGas's arguments outlined in the five paragraphs on pages 1, 2 and 3?
A Yes.
Q Did you discuss with Darryl whether or not

to include this violation based on SoCalGas's response?

A I looked at this letter, and then I looked at actually --

I was going to say that I looked at the analysis that SoCalGas did, but that was after the testimony came out. So I had this letter. I think that the main thing that I discussed with Darryl was that it was the statement on page 2, it says the --

See on page 2, the second full paragraph says, "Consistent with those statements air samples taken by DPH and other agencies during and immediately after the incident were analyzed for compounds that are typically found in crude oil, including benzene, toluene, ethylbenzene and xylene," which is typically referred to as BTEX.

That statement concerned me because naturally those four things are typically found in crude oil, but they would not necessarily tell you what heavy components of oil might be dropping out of the air emissions from the well.

So I felt like this is only a partial -- a partial answer, that it seemed like DPH had asked for a more extensive analysis of the air emissions, the gas emissions and didn't get it.

Q As framed the violation relates to a failure to disclose, correct?
A I understand that, and I agree with you, yes.
Q Okay. Thank you.
Turn to page 52, please.
A Okay.
Q See paragraph 2, "In Multiple Instances, SoCalGas Did Not Cooperate with SED During Its Pre-Formal Investigation Following the Incident on Aliso Well SS-25 that Began on October 23, 2015."
Do you see that paragraph?
A Yes.
Q You were not personally involved in SED's preliminary investigation, correct?
A No.
Didn't we discuss this earlier? Seems like we've already been through this one.
Q Not what we're about to discuss.
A Okay.
Q Did you --
And again, to confirm though, you didn't talk to anyone related to these violations other than Mr. Gruen, correct?
A That's correct.

Q Okay. With respect to SoCalGas's failure to produce Boots & Coots witnesses for an examination under oath, what did you review?

MR. GRUEN: I'm sorry, is there a particular area of testimony that you're asking about?

THE WITNESS: I think it must be back --

BY MR. STODDARD:

Q See page 55 if you need to.

A There are letters referenced in the footnotes 390 and 391.

Q So a letter from SED Director Malashenko and again another letter from SED Director Malashenko.

A Yes. Let's see if there's more.

On page 56 there is additional footnotes. And I did not see subpoenas, I did see correspondence.

Q You didn't see the subpoenas because they weren't included, or you didn't review them?

A I didn't review them.

Q In your practice as an attorney, have you ever propounded subpoenas on witnesses?

MR. GRUEN: I'm going to object to relevance here.

THE WITNESS: Not related to utilities.

BY MR. STODDARD:

Q In any context?
A A couple of times.
Q Have you ever provided a subpoena on another party to compel appearance of a third party?
A No.
MR. GRUEN: Same objection.
MR. STODDARD: I'm going to introduce Exhibit 1-32.
(Deposition Exhibit 1-32 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A I think I've seen it before.
Q If you turn to page 56 of your testimony, you'll see this letter excerpted starting at the bottom of 56.
A Yes.
Q And continuing all through page 57 and 58.
A Yes. Right.
Q We would note that despite the liberal quotation, it excludes most of the discussion -- actually the entire discussion of law from the letter.
If you will reference page 3 of the letter

itself, Exhibit 132.

A Okay.

Q Do you see what --

Do you see that there the discussion of law starting with reference to Snyder v. Southern California Edison?

A Yes.

Q And you agree that that is not included in this testimony?

A Yes.

Q Do you recall reading this?

A I -- I read it. I didn't spend a lot of time on the law part.

Q But you considered it?

A Yes.

Q And do you agree that SoCalGas cannot legally compel appearance of a third party --

MR. GRUEN: Objection.

BY MR. STODDARD:

Q -- without legal process?

MR. GRUEN: Objection. Calls for legal conclusion.

You can answer if you're able.

THE WITNESS: My participation in this testimony is technical, not legal.

BY MR. STODDARD:

Q So you can't testify to the facts in this violation?

A To.

MR. GRUEN: Objection. Mischaracterization of testimony.

BY MR. STODDARD:

Q Are you able to testify to support this alleged violation?

A The violation is just as I read it, that you refused to produce a witness over a period of time when you were requested. That's factual. The argument underlying that is legal, and I did not develop that or spend any time reviewing it; so my part of the testimony is only on the facts.

Q But you have yourself prepared and served subpoenas, correct, for appearance of witnesses?

A Yes. I don't know how that is relevant in this particular contract that I have with the PUC.

Q Well, you're aware how subpoenas work?

A Yes.

Q Okay. And you've never, between --

To restate what you said earlier, you've never served a subpoena on a third party -- on a party for production of another party?

MR. GRUEN: Objection. Asked and answered.
THE WITNESS: No.
BY MR. STODDARD:
Q Do you believe it should be a violation of law if SoCalGas is compelled to do something that is not within its legal power to do?
MR. GRUEN: Objection. Calls for legal conclusion.
THE WITNESS: Yeah.
MR. GRUEN: I've got to say, this is -- it's --
We've been here cooperating, now it's going on the -- I think the eleventh hour, and now we're continuing to discuss calling for legal conclusion.
We agreed to come down here and do this deposition.
MR. STODDARD: You asked to come down here and do this deposition, it was your request.
MR. GRUEN: We agreed to do the deposition.
Let's not mince words. We agreed to do the deposition, but we're going on and on.
And we did not agree to come down here and provide Ms. Felts to answer questions that are calling for a legal conclusion. That's beyond the scope of what we've agreed to do here.
If we're going to keep going down this

road --

I think this line of questioning about legal conclusions and what her views are on the law should wrap up maybe in a question or two.

MR. STODDARD: Are you instructing the witness not to answer the question?

MR. GRUEN: No, she can answer. But the line of questioning is wasting our time.

MR. STODDARD: Darryl, we were happy to come to San Francisco, you guys wanted to do it down here.

We have a right to our deposition.

MR. GRUEN: That's --

MR. STODDARD: And she has asserted violations that -- a lot of them are based, frankly, on law. And the truth is, if she can't testify to those facts, we would ask for a witness.

MR. GRUEN: That is completely mischaracterizing what I'm saying.

I'm going to read for the record in light of this -- if you'll indulge me, we're going to have to go here, I hoped we wouldn't. But bear with me a second.

Can we go off the record for a second?

MR. STODDARD: Actually, in the interest of time, because I know we want to keep moving, can I

try restating the question and see if your objections continue?

MR. GRUEN: Of course.

MR. STODDARD: All right.

Q Are you aware of any authority that would permit SoCalGas to compel production of a third-party entity?

MR. GRUEN: I'm going to restate the objection and I'm going to note here that --

I'm going to read a quote from the pre-hearing conference statement, the transcript, at pages 43 and 44, that we -- that captures the understanding that we've had.

Unfortunately -- so this starts to quote ALJ Kenny.

"The next question concerns the deadline for SED to submit alleged violations and the factual and legal justifications for each alleged violation. My question is whether it would be reasonable to set a deadline of opening testimony for SED to submit alleged violations and the factual justifications for each alleged violation and set a deadline for

opening briefs for SED to submit the legal justifications for its alleged violation.

"Would any apparent like to respond to my question? SoCalGas."

Quoting Mr. Stoddard:

"SoCalGas's position on this is that SED should identify the alleged violations with specificity in its opening testimony sooner, if possible; but in its opening testimony would be acceptable to SoCalGas as we had proposed in our prehearing conference statement."

My co-counsel, Mr. Sher:

"Your Honor, SED would not necessarily be opposed to such if SoCalGas agreed that now that it would not waste time cross-examining SED's witness as to their legal basis for tying violations to code sections, et cetera."

"ALJ KELLEY: Does SoCalGas have a response at this time?

"MR. STODDARD: SoCalGas is not

going to waive any rights to cross-examination. Although I would ask for clarification what exactly is meant by 'legal basis' here.

"MR. SHER: The way your Honor set this out is that the violations would be set forth in the opening. And then the legal issues" --

I might highlight the legal issues there, continuing the quote --

-- "would be discussed in the briefing. To the degree it is likely" -- "highly unlikely that SED's witness would be a lawyer, so we don't want SoCalGas, if we are going to do this all in our opening testimony, to cross-examine the witness as to their legal basis for concluding that this is a violation, for example 451.

"MR. STODDARD: SoCalGas does not object to that."

Thank you.

It was SED's understanding that preparing the violations at SoCalGas's request would not lead to a set of questions of the witness as to the legal

analysis that would be required to support them underlying the testimony. These are briefable issues. That's why I'm recommending that we move on, we cut this line short.

If you want to continue with this line of questioning, we're here, but we maintain that this is a waste of time to do it here.

MR. STODDARD: An important part of that that you read was Nicholas's statement that your witness was not likely to be a lawyer, and it was -- part of it, what he said there was predicated upon that representation. First.

Second of all, this isn't cross-examination, this is discovery.

Third --

Can I see this?

-- this issue has been addressed before in front of the Commission. This is a transcript in which Ms. Felts was a witness in the PG&E San Bruno proceeding.

Are you familiar with this?

MR. GRUEN: I haven't seen the transcript that you're referring to. I don't know if I'm familiar or not. I'm sorry.

MR. STODDARD: Counsel for PG&E, Joe Malkin, was

representing -- was representing PG&E, and Bob Cagen was opening ORA. Bob Cagen stated an objection to a line of questioning related to Rule 1, said "Excuse me, Your Honor, I think I'm going to object to this. This really is calling for a legal conclusion rather than anything else that is valuable in the way of fact finding."

Joe Malkin said "Well, Your Honor, this witness has told us that she is advocating that the Commission find PG&E guilty of this Rule 1 violation. I am probing her thought process and what underlies her advocacy to the Commission. And to the extent that Mr. Cagen is concerned that we're sliding over into legal opinions, as you heard yesterday, Ms. Felts is, in fact, a lawyer; so the objection of a legal issue being addressed today by a non-lawyer, which was raised by Ms. Halogan yesterday, doesn't apply."

And the judge said "Okay. I'm going to allow it. Go ahead."

And the judge in this case was your co-counsel, Amy Yip-Kikugawa. And --

MR. GRUEN: Can I have an opportunity to respond to that?

MR. STODDARD: -- the discussion we had at the

pre-hearing conference was not reflected anywhere in the judge's scoping ruling.

Ms. Felts is asserting violations of law throughout her testimony. You had the ability to scope your testimony however you saw fit and you chose to do it that way. And you included law, but you also included conduct. And the question that we're asking relates to the connection of the conduct and the law.

MR. GRUEN: If I may.

I appreciate you raising the issues.

I will note that SoCalGas, in its response to our request to provide a person most knowledgeable related to the -- the SoCalGas's alleged assertions regarding Mr. Bruno. In response to our request for a deponent, we had understood that SoCalGas had only attorneys and argued that it couldn't provide someone on that basis was our understanding.

And when the ALJ ruled that, in fact, SoCalGas was to provide a non-attorney, SoCalGas continued to provide someone who is, in fact, an attorney. I understand he is not in that role as a represented counsel. However, Mr. Jason Egan, according to my last checking on the State Bar of California website yesterday, is indeed a licensed

attorney, and yet he is being provided to provide testimony in that deposition; so it's the same thing, yet our understanding, per the ruling, is he was provided as indeed a non-attorney in compliance with the ruling, similar to what we're doing here.

I understand there are a number of attorneys practicing for SoCalGas who I've had the ability to come in to work with who indeed are attorneys but don't appear or practice as designated counsel for SoCalGas. That's one.

Two, it remains our position that questions about discovery for purposes of this exercise are no different, are no different than cross-examination; so this line --

It is for the purpose -- to the extent this is for the purpose of determining cross-examination, we maintain there is no distinction. That's a distinction without a meaning.

We think that this --

We distinguish from San Bruno, this is its own set of facts and circumstances. We came to an agreement and understanding in reliance that SoCalGas on the record at the pre-hearing conference wanted SED to produce violations right away, and that we would have the ability to brief the violations. We

didn't have to do that, SED didn't have to produce violations.

There is no telling had we not come to this resolution what the ALJ would have instructed. But we've done so, and we are concerned that SoCalGas frankly is not in good faith in asking these questions at this time and asking for the basis for legal conclusion.

So with that, that's our response. That remains our position. It's not appropriate to be asking Ms. Felts these types of questions here.

But with that, you can continue with your line of questioning.

MR. STODDARD: I'd like to make a couple of other remarks for the record.

Frankly, I don't understand your point about Jason Egan, but we can move on from that.

Secondly, I don't know that it would be necessary to be asking Ms. Felts these questions if SED responded to our written discovery along the same lines, where we've asked you to explain legal basis and positions which SED should be capable of doing if it doesn't want to subject its witness to those questions.

One of the reasons for asking questions

related to legal basis or contentions or anything else is to help narrow the parties -- the scope of issues in dispute and bring the parties together for purposes of determining the issues that actually should be litigated in an evidentiary hearing.

Everything in here that has been alleged related to the Boots & Coots violation, is simply related to SED's misunderstanding of the law. And we are trying to ask questions about that so we can better understand what your position is.

MR. GRUEN: I'm going to object to that characterization as mischaracterizing SED's testimony. That's just simply an inappropriate mischaracterization.

I'm sorry if you don't understand our point about Mr. Egan, we can go back on the record and understand it. I don't know how to articulate it any better, Jack. I'm sorry that it has to come to this.

But we're here. If you want to continue to ask questions, we --

Again, we don't think this is appropriate to continue down the road of asking about legal conclusion, but if you're going to do it for purposes of the deposition, then continue with your line.

MR. STODDARD: I hadn't finished what I was

saying, but I will continue my line of questioning in a moment.

The next --

The only other thing I wanted to mention, just in case it was unclear, was we aren't conceding anything with respect to cross-examination. I was simply noting that this is not a cross-examination.

Again, our reading of what occurred -- you know, our reading of ALJ Amy Yip-Kikugawa's ruling at the San Bruno case we think is applicable here. We don't think that the judge relied on that discussion for purposes of the scoping ruling. And if we have to go to the judge over this, we can.

MR. GRUEN: We're agreeing to answer questions.

I would say it's also a mischaracterization to call Amy Yip-Kikugawa my co-counsel. She is an Assistant General Counsel at -- and she is my direct supervisor. She is not an assigned counsel to this proceeding.

Just to make it clear, that's Nicholas and myself. We're the designated counsel of record, just to clarify.

And the ruling there has, to my -- and you can enlighten me, there has been no ruling saying that Ms. Felts has to answer questions regarding

legal conclusions, that call for legal conclusion. But if you want to take that to the judge, we understand, and we can handle the issue that way.

Like I said, she is available to answer questions at this point.

MR. STODDARD: Okay.

Q Turning to page 54, Ms. Felts.

A Okay. I'll get it later.

MR. GRUEN: Okay.

BY MR. STODDARD:

Q This alleges four violations related to alleged data dumps of documents on Blade.

A Yes.

Q Did you review the contents of these data dumps?

A I have reviewed some of it, but I have not reviewed the actual files that Blade received. I believe I have reviewed some of the documents that were in possession of the PUC that were similar.

Q And you didn't interview Blade regarding the context of the data dumps, did you?

A No.

Q Did you review any correspondence between SoCalGas and SED on this issue, including data responses?

A On this issue?
Q Yes.
A What data response would it be, could you tell me?
Q We can follow up with that.
But do you recall as you sit here, reviewing a response to a data dump?
A I think I did review some things, but I can't tell you what data response it was in or what the extent of the documentation was.
Q Okay. For purposes of the record, it looks like I didn't actually get an answer to my question prior to the exchange with Mr. Gruen; so I'm going to ask it again, and we can just get it on the record.
Are you aware of any authority that would permit SoCalGas to compel production of a third-party entity?
MR. GRUEN: And re-note the objection as calling for legal conclusion.
THE WITNESS: No.
MR. STODDARD: Thank you.
Q With respect to the Blade data dump we were just discussing, you indicated you may have reviewed some of the documents?
A Yes.

Q Did you assess materiality of the documents to Blade's RCR report?

A I don't know what that means.

Q Did you consider whether or not the documents had bearing on any of the issues that Blade reached conclusions on in their Blade -- in the Blade report?

A I think I answered that question when I discussed the apparent lack of temperature surveys or their -- the fact that they appeared not to have them until review for Well SS-25. Other than that --

And they said they didn't have permeability of the reservoir, which wasn't in the Well 25 -- SS-25 file anyway. I would say that most of their conclusions were based on their own work with the well and their own investigation into the well casings, their groundwater monitoring wells.

So they developed most of their own -- their own information. It's possible that had they had the time to look at all of the data that SoCalGas provided them, they might have had additional information to inform them on more details of the case. I just don't know.

Q Thank you.

When did you review the data doc -- data

dump documents that you reviewed?

A I didn't -- I didn't review anything other than that one well file prior to filing the testimony.

Is that what you mean? I mean, you're talking about SoCalGas records?

Q Yes.

A Yes.

Q Ms. Felts, circling back to the privilege violations, and if we don't -- if we have to reference the testimony, we can. But we can speak without a document if we're able to.

You're aware that each alleged privilege violation is framed as both a violation of 451 and 1.1, correct?

A Yes.

Q Can you explain why in your view each privilege violation is -- constitutes a violation of Public Utilities Code 451?

MR. GRUEN: Objection. Calls for legal conclusion.

Can we go off the record for a second?

MR. STODDARD: You've stated your objections, Darryl.

MR. GRUEN: I know.

MR. STODDARD: Are you going to let us ask her a question?
MR. GRUEN: Absolutely.
We have --
MR. STODDARD: We can go off the record.
MR. MOSHFEGH: There is a question pending.
THE VIDEOGRAPHER: Just a moment.
MR. GRUEN: Okay. We can wait until the question is done.
THE VIDEOGRAPHER: Go ahead.
THE WITNESS: Okay. 451 is related to safety, so a duty to operate safely. Is that --
Do you want more?
BY MR. STODDARD:
Q So did you determine that the documents here that were withheld jeopardized safety?
A The concept was that you -- the delay in getting the documents created an unsafe situation because there was no way to respond to the documents without -- or to use the documents unless they were provided.
Q Would it be relevant to your opinion on these violations if --
I asked earlier several if several of the documents were duplicates, as you'll recall.

Would it be relevant to your opinion on these violations if many of these documents were already in SED's possession?

A I -- I have to wonder why we don't have them, what the purpose of not disclosing them is. If we already have them, why couldn't you just tell us we already have them.

Q For example, attachments to emails that would have been otherwise privileged, attachments to privileged documents are privileged, but they're included for purposes of the calculation of penalties.

A Is that how they ended up being pages?

Q Is that relevant in your view to the assessment of a violation in this instance?

A I think it's probably relevant. You have to have all of the information in order to count.

MR. GRUEN: If you finished that line, can we go off the record now for a moment?

BY MR. STODDARD:

Q Do you know what, if anything, SED would have done differently had it received these documents earlier?

A You might not have that violation.

Q Do you know what, if anything, SED would

have done differently with respect to their investigation?

A Not without knowing what the -- what the records are.

Q The records that were produced to you, which are in your possession, these are the documents that the privilege violations are based upon.

A Oh, and that have now been produced?

Q Yes.

A Without looking at each one of the documents, I can't tell you what --

I was never asked to look at them in that manner.

Q Are you aware if any of the documents are relied upon in your testimony in any citation or exhibit for purposes of supporting other alleged violations?

A I don't know. But I don't think so.

MR. STODDARD: Okay. Thank you. We can go off the record.

THE VIDEOGRAPHER: We are off the record at 7:42 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 8:06 p.m.

MR. STODDARD: All right, Ms. Felts, I'm going to promise to keep this short hopefully. But we'll be jumping around a bit just because this is kind of the scraps at the end, so bear with me.

Q To begin with, I'm going to ask, do you consider yourself, Ms. Felts, an expert on attorney-client privilege?

A No.

Q Are you aware of any hard drive of Blade data that was produced to SED?

A Yes.

Q And have you accessed that?

A No.

Q So you haven't reviewed any of the records that are on that drive?

A Not yet.

MR. STODDARD: Okay. I'm going to introduce Exhibit 1-33.

(Deposition Exhibit 1-33 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yeah, it looks like something I wrote.

Q This is an email from you --

Well, to be clear this includes two emails: The top one is from you to Karen Shea and Darryl Gruen, and it includes an attachment "Draft Data Request"; is that correct?

A Yes. Well, that's what it looks like.

Q And the bottom email is also from you to Karen Shea, and it appears to be related to the draft data request as well?

A Yes.

Q Turning the page, in referencing the attached data request, and again, this is just for purposes of the record, Exhibit 1-33, the email dated November 8, 2019, and the draft data request, the first data request is for -- it asks to provide a summary of all data requests that SoCalGas has received related to I1906016, including those received from the CPUC before and after the initiation of investigation from DOGGR Blade and third parties; is that correct?

A Yes.

Q Did you prepare that request?

A Yes.

Q Why did you prepare that request?

A At the time I understood that the data that was available at the PUC was incomplete, an

incomplete set, and it was also not readily accessible to me. And so there was some discussion back and forth about how to get a full set of data.

Q And was it not --

Was it incomplete and not accessible in part because of the corrupted files you referenced earlier?

A That's part of the issue. Things wouldn't open. Other issues were there was some thought that some of the data that had been provided by SoCalGas in thumb drives may not have been uploaded. I don't think that was the case.

But at the time -- at the time when I couldn't find it on the Diamond database, that was mentioned that they thought maybe, maybe they weren't uploaded.

Later I found out that it was just organized a different way, and I was able to find some of it. Did not solve the corrupted files problem.

Q Was any of the data lost, to your knowledge?

A What do you mean by "lost"? Like did they lose a thumb drive?

Q Or was it, you know, simply not in SED's possession despite the fact that it appeared it had been transmitted to SED?

A I can't really tell you that. I don't have a good feel for what came in, what should have been uploaded and what should not have. I just don't have a good solid sense of what all SoCalGas provided. And I wanted to get it directly from SoCalGas again, but apparently you said no; so then we took steps to try to get a set of data from -- directly from Blade, and that was difficult too.

Q In the course of preparing this request, I imagine you had conversations with Ms. Shea and Mr. Gruen about the need to ask it?

A Yes.

Q Including discussions about how you could access the data, correct?

A Yes.

Q And where it was?

A Yes.

Q In the course of those discussions, did anyone indicate that the data had been lost?

A There was a thought that -- not that it had been lost but that maybe it was not uploaded. There was also a comment that the thumb drives had been uploaded and then discarded. Because we thought maybe if we could get the thumb drives, I could look at it directly from those. But I have not been

provided any thumb drives.

Q Why couldn't you --

If it had been uploaded from the thumb drives, why couldn't you look at the data that was uploaded?

A Well, because the files weren't opening. And a lot of the larger files were opening with the message that said the file was corrupted; so there wasn't any way for me to recover it.

Q Do you recall from those discussions any reference to FTP transfers?

A We talked about this earlier. I had --

I got capability to do FTP out, but there was no discussion about --

Q I'm sorry, I'm asking a different question.

A Okay.

Q We did talk about it earlier, correct?

A Yes.

Q I'm asking whether --

You mentioned that SED had received files from SoCalGas via thumb drive?

A Yes.

Q Are you aware whether SED also received files from SoCalGas via FTP?

A No.

Q Okay. So you don't recall any discussion about expired FTP transmittals?

A I think somebody --

Actually, I think I received a link maybe from Karen or Darryl that had expired. I tried the link.

Q Thank you.

Ms. Felts, we were discussing casing inspection logs earlier.

Do you have any personal experience with the Vertilog tool?

A Other than just reading logs? No.

You mean like running a wire line test or -- and generating one?

No.

Q How about interpreting logs --

A Yes.

Q -- Vertilogs specifically?

A I have read those, yes.

Q And in what context?

A Well, beginning in school I had a whole course on that, and then over a period of time I have had occasion in private consulting cases to look at well logs.

Q Again, we're talking specifically about

Vertilog logs here.

A Well, I think a Vertilog is one of many different kinds of logs; so I'm sure I've looked at them. I just can't tell you exactly which case, what date.

Q And what is your understanding regarding the reliability of Vertilogs -- the Vertilog tool?

A There were probably some issues with them over time. They've probably gotten a lot better recently.

Q Okay.

MR. STODDARD: Introduce Exhibit 1-34.

(Deposition Exhibit 1-34 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q In connection with Exhibits 1-17 and 1-18. Ms. Felts, do you recognize this?

A No.

Q This is the metadata file for an email for the document attached to the Tuesday, November 19th, email from Darryl to you, if you reference Exhibit 1-17 and Exhibit 1-18.

A 1-17 and 1-18?

Q Correct.

Do you have 1-18 there?

A I have 1-18.

Is that good enough?

Q That's good enough.

A Okay.

Q This is the metadata file for document 1-18, which is the draft testimony that was transmitted to you by Darryl Gruen, and this is SED's portion of the testimony.

A Okay.

Q And you'll see there that identifies the manager author as Randy Holter.

A Uh-huh.

Q And you don't know and haven't spoken to Randy Holter, correct?

A No.

Q And the secondary author it identifies, last modified -- the document was last modified by Darryl Gruen.

Do you see that?

A Yes.

Q And it doesn't identify any other authors?

A Okay.

Q Do you see that?

A Uh-huh.

Q Ms. Felts, seeing this and having gone through the preparation of your testimony in the period of time between the engagement and the service of your testimony, do you think it would make more sense for Mr. Holter to be the testifying witness on some of these issues than you?

A I have no idea. I don't know what his expertise is. And I don't know that he actually wrote the testimony. He could have just opened the file on 10-19 or 11-19 or whenever it was created. I guess it was created sometime around 9-23 maybe.

Q And --

A Hard to tell.

Q And if he just opened the document, then that would mean Mr. Gruen drafted the testimony based on this metadata; is that correct?

A No, not --

I mean, metadata, this only goes to this electronic file; so the file could be saved as another document, as a new document. You could start over.

I don't -- I don't know that you can really glean a whole lot by this particular metadata.

Q Ms. Felts, with respect to your portion of the testimony, which is related to the recordkeeping

violations --

MR. GRUEN: Objection. That's a mischaracterization of testimony.

She has identified that she is sponsoring the whole -- the entirety of the testimony, not just recordkeeping.

MR. STODDARD: I'm sorry, let me correct that.

Q With respect to the portion of the testimony that you wrote, which relates to the recordkeeping violations, Ms. Felts, what is your experience with recordkeeping practices at gas storage fields?

A Only that I reviewed records for the Playa del Rey and the Montebello cases.

Q So you haven't looked at recordkeeping practices at other gas storage fields?

A No. I only looked at the recordkeeping entries in the PG&E records retention documents. I think I provide those to you in response to a data request.

Q And aside from that, nothing else?

A No.

MR. STODDARD: Okay. I think that's it.

THE WITNESS: Do you want to redirect?

MR. GRUEN: I just want to be sure.

MR. STODDARD: Apologies.

One more document.

MR. GRUEN: Okay.

(Deposition Exhibit 1-35 was marked for identification and is attached hereto.)

MR. STODDARD: Mark this as Exhibit 1-35.

Q Ms. Felts, do you recognize this document?

A I don't think I've seen this document.

Q You did indicate that you accessed the Commission's Aliso Canyon Web page, correct, but you had trouble downloading a Blade report from there, I think?

A Yes.

Q Do you see down about three-quarters of the way down the page --

A Okay.

Q -- where it says "Both the Division," I guess at the bottom, both "The Division and the PUC have directed the Gas Company to hire an independent third party to perform a technical root cause analysis of the well failure"?

A Yes.

Q Is it your understanding from your review that Blade's investigation has been fully independent?

A Yes.
Q Turning to Appendix B, do you see on page 1 the "Findings and Timeline"?
A Yes.
Q Do you see there in the first sentence of last paragraph where it states "SED will release its official investigation report upon completion of all aspects of its investigation"?
A Yes.
Q And to confirm, you're not aware of any such official investigation report; is that correct?
A Wasn't -- doesn't --
Isn't that related to the Blade report?
Q This is SED's report.
A Okay. I guess I misread that.
Q Are you aware of an SED official investigation report?
A No.
Q Okay.
MR. GRUEN: I just note a foundation objection for the record.
She has noted that she hasn't seen this document before, she doesn't recognize it.
But the questions are noted.
MR. STODDARD: All right. That's it.

MR. GRUEN: Okay.
MR. STODDARD: Go off the record?
MR. GRUEN: Yeah.
MR. STODDARD: Do you have any other comments?
MR. GRUEN: Yeah. I'll wait until we're off.
THE VIDEOGRAPHER: We are off the record at 8:27 p.m.
(Off the record.)
THE VIDEOGRAPHER: We are back on the record at 8:31 p.m.
MR. GRUEN: While we were off the record, SoCalGas and SED agreed that Ms. Felts can offer a clarification statement for her earlier testimony today. And if so SoCalGas wants to ask follow-up questions on that statement, SED has no objection.
Go ahead.
THE WITNESS: Okay. Do you want me to just say what it is?
MR. GRUEN: Yeah.
THE WITNESS: That one?
MR. GRUEN: Yeah.
THE WITNESS: Well, so you asked me about my contractor license earlier, and I looked it up, and it is called -- in California it's called an a general engineering contractor license.

So when I said general engineering license, I think maybe I misspoke and didn't add the "contractor" on. But somehow it was misunderstood. I just wanted to clarify that.

I have put that on inactive, and apparently in the last couple of years privacy must have gotten to the contractor -- the state license board because you can no longer look it up under my name if it's inactive; So some old -- an old license number when I was incorporated comes up under Invictus as not -- not inactive, but it's actually a dead license.

The current one that is inactive, I would have to provide you the license number, and I don't have it with me. But I could do that if you want it. And then I think it will come up maybe.

MR. STODDARD: Okay.

THE WITNESS: But I think I could get those records if you needed them.

MR. STODDARD: Yes, we would appreciate that.

Well, actually let me ask one quick question.

Q What is the purpose of the general engineering contractor's license?

A It's basically the top tier of general contractors license. It basically gives me license

in California to do any kind of construction on contracts.

Q And to subcontract?

A And subcontract. So a general --

Like if you go hire a general contractor to build a building, that would be me. Then I subcontract all of the work out and handle all of the permits and oversight; so it is a major category. It's the category if you want to be into construction.

I acquired it early on to be able to drill wells for groundwater monitoring and to be able to do hazardous waste cleanup. I did have to take an additional exam for the hazardous part of it; so mine says "A General Engineering Contractor-HAZ," which means I'm allowed to manage site cleanups where there is hazardous waste.

Q Okay. Yes, I think we would like to see copies of that --

A Okay.

Q -- license.

And just to reiterate, because I was confused about this earlier, but -- and I want to make sure I have it clear, and I apologize if I already asked this question.

Do you have any other engineering-related licenses or certifications or credentials?

MR. GRUEN: That she hasn't already identified in the course of the deposition today?

MR. STODDARD: Well, I just want to be clear that we're not --

I might be confused.

For sake of the record, we now have established and I understand the general engineering contractor's license.

Q Are there any others?

A No.

MR. STODDARD: Okay.

MR. MOSHFEGH: Confirm for one --

MR. STODDARD: Sure.

I don't think we necessarily need to. I --

Housekeeping item for purposes of the record.

We've noted that you've objected today to questions related to Ms. Felts' work since the service of opening testimony?

MR. GRUEN: Right.

MR. STODDARD: We don't -- we don't have those documents. Sounds like there might be additional work product being generated at this time; we don't

have access to that.

We are going to see her live testimony at some point in time, which presumably will be based on that work product and given that that's basis of the objection, so, procedurally, we would like to keep the deposition open, and the request for work papers in particular open so that after the next round of testimony is served, you would then produce to us any additional work papers.

MR. GRUEN: I think it's appropriate for a second -- if you want to produce --

If you want a deposition that is based on, then it's appropriate to do a new round.

This was understood to be a notice of deposition related to opening testimony. You know, you're entitled to propound discovery.

MR. STODDARD: We can notice a new deposition with the understanding that this is -- you know, it would be based on that objection, essentially.

MR. GRUEN: Yeah. And, you know, we'll bear it in mind.

But I will say, Jack, we're -- the timelines grow tighter. We're noting that the reply testimony is due February 21st, rebuttal is the 27th of March. The ability for us, with our limited bandwidth, to

juggle that additional deposition time with the ability to prepare testimony and do discovery is getting harder; so we just ask that you bear that in mind.

But we understand the request and if you want to request the -- we anticipate that you may want to request the work papers associated with future testimony as well. And we'll bear that in mind and work to cooperate on that discovery along those lines.

MR. STODDARD: Yeah.

Just to be clear, we wouldn't be requesting a deposition prior to your service of testimony --

MR. GRUEN: Understood. We appreciate that. Yeah. Okay.

MR. STODDARD: -- unless we get new information related to her testimony that wasn't produced today that you produce at a later date that is relevant to -- right, with that one caveat in mind.

But assuming when we're talking about the work papers for purposes of the reply testimony, our reservation for an additional deposition would be after the service of the reply testimony.

MR. GRUEN: And we have the same concern with rebuttal, of course, that immediately before rebuttal

testimony, we'll be busy in preparing that as well, the March 27th testimony.

MR. STODDARD: Right.

MR. GRUEN: Okay. Sounds like we can work that out okay.

MR. STODDARD: Anything further?

MR. GRUEN: Nothing further from SED.

Thank you.

THE VIDEOGRAPHER: This is the end of our deposition, the end of disk number five, Volume number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are off the record at 8:39 p.m.

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REPORTER'S DEPOSITION TIME LOG:

REPORTER - LINDA SILVER RYAN

DATE - Wednesday, February 5, 2020, 2019

WITNESS - MARGARET FELTS

ATTORNEY	ON RECORD	OFF RECORD	TOTAL
STODDARD	9:23 A.M.	10:55 A.M.	1:32
	11:13 A.M.	12:15 P.M.	1:02
	1:24 P.M.	2:30 P.M.	1:06
	2:47 P.M.	3:39 P.M.	0:52
	3:44 P.M.	3:52 P.M.	0:08
	4:25 P.M.	5:59 P.M.	1:34
	6:22 P.M.	7:42 P.M.	6:03
	8:06 P.M.	8:27 P.M.	0:21
	8:31 P.M.	8:39 P.M.	0:08
		TOTAL USED:	9:04

CHANGES AND SIGNATURE

WITNESS: MARGARET FELTS

DATE OF DEPOSITION: Wednesday, February 5, 2020

PAGE	LINE	CHANGE	REASON

STATE OF _____)
) Ss.
COUNTY OF _____)

I, the undersigned, say that I have read the foregoing deposition, and I declare, under penalty of perjury under the laws of the State of _____, that the foregoing is a true and correct transcript of my testimony contained therein, incorporating any and all changes and/or corrections as heretofore noted by me, and the reasons for same.

EXECUTED this _____ day of _____, 2020, at _____.

_____

MARGARET FELTS

I, the undersigned, a Certified Shorthand Reporter of the State of California, do hereby certify:

That the foregoing proceedings were taken before me at the time and place herein set forth;

That any witnesses in the foregoing proceedings, prior to testifying, were placed under oath;

That a verbatim record of the proceedings was made by me using machine shorthand which was thereafter transcribed under my direction;

That the foregoing deposition is a full, true and correct transcript of my shorthand notes so taken and transcribed;

That any dismantling of this transcript will void my certification as a Certified Shorthand Reporter;

I further certify that I am neither financially interested in the action nor a relative or employee of any attorney of any of the parties.

IN WITNESS WHEREOF, I have this date subscribed my name.

Dated: _____

_____

LINDA SILVER RYAN

CSR No. 9915

SoCalGas-5.0578

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