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

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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, Section 5 and Section 7 apply to new facilities, and facilities undergoing significant expansion. Section 6 applies to new well construction and remediation of a new or existing well. Specific portions of Section 5 and Section 6 may be applicable to existing reservoirs and wells as risk analysis, the availability of new data, or other information or conditions over the life of the facility warrants re-assessment. 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. The term “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 documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) 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*

API Recommended Practice 1170, *Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage*

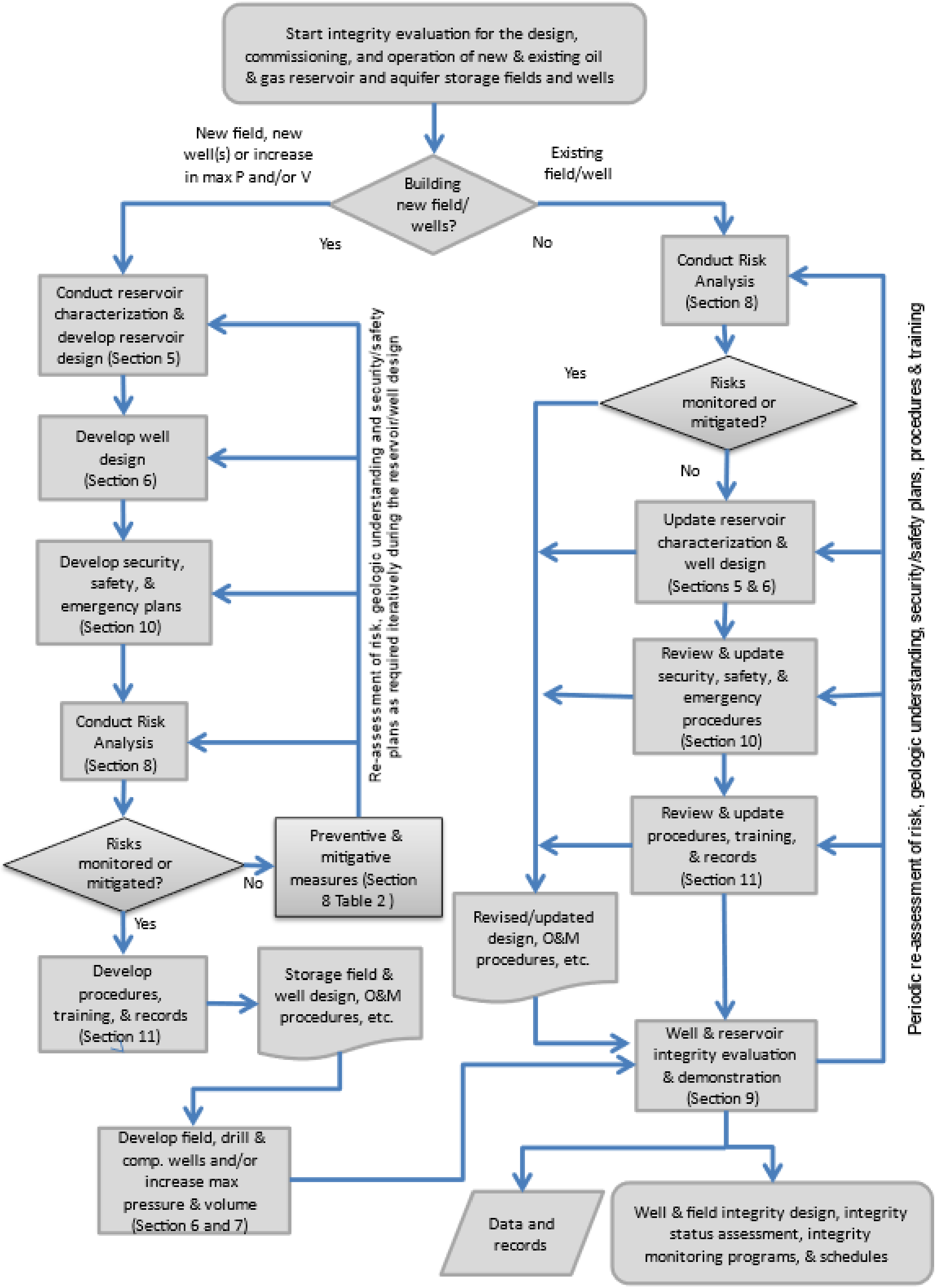

Figure 1—Flowchart of Document Sections

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and 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:

— indicate a condition exceeding design limits; or

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

— indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well 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
area of review
The underground gas storage reservoir and all wells associated with it, as well as all non-associated subsurface or surface structures, formations, or activities proximal enough that could impact or be impacted by the underground gas storage facilities and operation process.

NOTE Area of review includes the buffer zone.

3.1.5
as low as reasonably practicable
ALARP
Reducing risk to a level which is ALARP involves objectively determining the balance where the effort and cost of further reduction measures becomes disproportionate to the additional amount of risk reduction obtained.

3.1.6
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 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).

3.1.7
basal rock
Horizontal rock layer(s) that forms a seal (barrier) to fluid flow in the vertical direction at the lower boundary of a storage reservoir.

3.1.8
base gas
Volume of gas needed in a storage reservoir to maintain reservoir pressure to cycle the working storage volume and meet required deliverability rates.

NOTE Also commonly referred to as ‘cushion gas’ or “cushion gas” or “pad gas”.

3.1.9
buffer zone
Area or interval outside the defined gas storage reservoir, horizontally and vertically, 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.

3.1.10
caprock
Rock layer(s) acting as the vertical seal (barrier) preventing migration of fluids at the upper boundary of the storage reservoir.

3.1.11
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.

3.1.12
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.

3.1.13
collector formation
A formation, usually vertically above the gas storage reservoir, capable of trapping and accumulating gas.

3.1.14
communication
Fluid movement influence, which may be detected by pressure observation, fluid physical and chemical composition analysis techniques, or other means.

3.1.15
consequence
Outcome of an event affecting objectives.

3.1.16
containment
Ability of a reservoir to confine stored gas and prevent migration either laterally or vertically out of the reservoir.

3.1.17
contractor personnel
Person or entity used by the operator but not directly employed by the operator.

3.1.18
encroachment
Intrusion of a non-storage well or operations into the defined surface or subsurface storage area threatening the integrity of the storage operations.

3.1.19
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.

3.1.20
groundwater
Subsurface fresh water, potable water, or water that is or can be potentially used as a drinking water supply.

3.1.21
hazard
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.

3.1.22
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.

3.1.23
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.

3.1.24
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.

3.1.25
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.

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

3.1.27
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.

3.1.28
mechanical integrity test
Pressure test that obtains data that demonstrates if a well is mechanically fit for service and capable of storing natural gas within design limitations.

3.1.29
minimum reservoir pressure
Average stabilized shut-in reservoir pressure at minimum design capacity of gas in storage.

3.1.30
native gas
Unproduced gas indigenous to the reservoir that remains in the reservoir at the time of conversion to storage.

3.1.31
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.

3.1.32
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.

3.1.33
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.

3.1.34
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.

3.1.35
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.

3.1.36
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.

3.1.37
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 workflow activity and quality standards for a wide range of procedures.

3.1.38
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.

3.1.39
risk
The consequence's severity of a realized threat multiplied by the likelihood of its occurrence.

3.1.40
risk analysis
Process to comprehend the nature of risk and to determine the level of risk.

3.1.41
risk assessment
Overall process of risk identification, risk analysis and risk evaluation.

3.1.42
risk evaluation
Process of comparing the results of risk analysis with risk criteria to determine whether the risk and its magnitude is acceptable or tolerable.

3.1.43
risk identification
Process of finding, recognizing, and describing risks.

3.1.44
risk management program
Coordinated activities to direct and control an organization with regard to risk.

3.1.45
safe work practices
Written methods outlining how to perform a task with minimum risk to people, equipment, materials, environment, and processes.

3.1.46
spill point
Point or area in a hydrocarbon trap at which the trap can be breached.

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

3.1.47
threat
created by an encounter with or an activation of a hazard during the storage operation.

3.1.48
wellhead
Assemblage of surface equipment used to maintain control of the well and to permit access into the wellbore.

3.1.49
working gas
Volume of gas in the reservoir above the designed level of base gas.

NOTE Also commonly referred to as "top gas" or "current gas".

3.1.50
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.

ALARP	as low as reasonably practicable
API	American Petroleum Institute
BPV	back pressure valve
CFR	Code of Federal Regulations
ERP	emergency response plan
H_2S	hydrogen sulfide
ID	inner diameter
MOC	management of change
MWD	measurement-while-drilling
O&M	operations and maintenance
pH	hydrogen ion potential
P&M	preventive and mitigative
PSL	product standard level
SSSV	subsurface safety valve
Tcf	trillion cubic feet
TD	total depth
VR	valve removal
WCP	well control plan

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.

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 were 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 to 1946. As of 2015, there were 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 Recommended Practice 1170 [1] 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 several 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 several means to evaluate reservoir integrity, well integrity, and fluid chemistry.

In practice, 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.

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 natural gas storage capacity development in hydrocarbon production reservoirs and aquifer reservoirs and increased maximum pressure or total capacity in existing natural gas storage reservoirs. The assessment steps are arranged generally in order of increasing effort and resources, beginning with use 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 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 shall encompass the intended reservoir 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.

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.

NOTE The preventative and mitigative measures presented in 8.5 can help to address anomalous geologic features.

5.3 Reservoir Engineering 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 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 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 used and the placement of the plugs, effectively prevent fluid migration. Six provides guidance regarding 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. Initial and current reservoir pressure shall be identified. For existing storage fields being considered for expansion, prior gas storage operational records should be analyzed 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.

NOTE The preventive and mitigative measures presented in 8.5 can help to address potential mechanical integrity issues.

5.4 Containment Assurance of Storage Design

5.4.1 General

Data shall be acquired to and interpreted to develop a facility design and operating plan that eliminates or manages 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 1 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 cause the design pressure limits of the reservoir, wells, wellheads, piping, or associated facilities to be exceeded.

NOTE 2 Certain activities, such as storage injection operations or wellbore stimulations, can require a pressure at a level higher than the maximum reservoir pressure.

The minimum reservoir pressure should not be designed less than historic minimum operated pressure unless reservoir geo-mechanical competency can be demonstrated. The impacts of intended minimum reservoir pressure should be accounted for in a regional review of the geologic horizon as it relates to geo-mechanical stress, reservoir liquid influx, surface facility gas cleaning and liquid handling, and liquid disposal, all of which affect the maximum cycling capacity of the storage field and can impact mechanical integrity of the facilities. The minimum reservoir pressure determination can include supplemental well drilling, coring, and laboratory analyses to provide data for the evaluation.

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 or well logging 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 shall be evaluated. 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 observation shall be performed 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 may be obtained and used for this characterization.

5.4.6 Other Design Factors

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

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

— 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 10.

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 Recommended Practice 51R [2] and API Recommended Practice 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 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 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.

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.

NOTE Operators may find it beneficial to retain geological, well drilling, completion, and abandonment records beyond abandonment of storage operations.

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 Specification 6A [4], API Specification 6D [37],or an equivalent standard.

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 determine if limited or less-than-full-bore 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 1 The pipeline isolation valve, as defined by the operator, can be a pipeline jurisdictional or regulated valve.

NOTE 2 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.

NOTE 3 New and replacement wellhead and tree components may be equipped with back pressure valves (BPV) and valve removal (VR) plug profiles to assist with component replacement.

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, testing, 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 or temperature monitoring of tubular and annular spaces.

6.2.4 Existing Equipment

Existing wellhead and well 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 valves, in new facilities which may include reviewing and documenting 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 Specification 14A [6] and API Recommended Practice 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.

6.3 Well Casing and Tubing

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/tubing shall be designed in accordance with API Technical Report 5C3 to safely contain the internal casing/tubing pressures and withstand the external casing/tubing pressures through the setting depth. The operator should determine its own guidelines for establishing safety factors for use with API Technical Report 5C3 calculations, recognizing minimum design safety factors that may be dictated by applicable regulations. New tubulars shall meet API Specification 5CT specifications.

6.3.2 Conductor Casing

Where used, the conductor casing shall 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 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 Recommended Practice 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 Production Tubing

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

6.3.7 Handling

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

6.3.8 Connections

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

For wells where enhanced load capacity and sealability is required, the use of premium connections with a dedicated metal-to-metal seal should be considered.

Casing or tubing connections shall be made up according to manufacturer specifications or in accordance with API Recommended Practice 5C1.

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

NOTE API Recommended Practice 5C5 [34] and API Technical Report 5C3 provide additional guidance in tubular connections which may be helpful when selecting connections for service.

Annex A presents a summary of various types of connections commonly used for downhole tubulars.

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 and cement materials should meet quality standards in API Specification 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.

Surface Casing—The cement slurry design should provide for a volume greater than 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.

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 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, to isolate 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 greater than 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 should 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, dry, and additive samples should be obtained from each cement blend pumped and kept through completion of workover, drilling, or until such time cement integrity is verified.

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 structural integrity and isolates 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 Standard 65-2 [11] provides guidance on conditioning the fluid in the wellbore.

The operator should use spacers 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.

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 Recommended Practice 10D-2 [12] and API Technical Report 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 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 (e.g. 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 considered 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 of strings deeper than the surface casing shall be evaluated with a cement bond log or other means. 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 Technical Report 10TR4 [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.

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 6.10) of each casing string, excluding conductor casing, shall be completed prior to drilling out or perforating.

6.5 Well Barriers

6.5.1 General

Well barriers are critical in containing reservoir fluids during gas storage service. Well barriers consist of barrier elements and barrier envelopes. A well barrier envelope comprises several barrier elements which form a barrier system to prevent uncontrollable fluid flow. Well barrier elements are the individual parts of the well's construction that make-up the barrier envelope. The objective of well barriers is to contain reservoir fluids within the wellbore.

NOTE ISO 16530-1 [35] provides guidance on primary and secondary barrier identification and performance verification.

6.5.2 Primary Barrier Envelope

The primary barrier envelope in a storage well are all the well barrier elements routinely exposed to reservoir fluids that maintain well integrity. Examples of some of the barrier elements that make up the primary barrier envelope are as follows:

— production casing;

— production tubing;

— production liner;

— wellhead;

— surface wellhead valves/safety valves;

— down-hole packer/safety valves; and

— cement.

6.5.3 Secondary Barrier Envelope

The secondary barrier envelope is designed to maintain well integrity independent of the primary barrier but is not routinely exposed to wellbore conditions. Not all existing wells have a secondary barrier envelope.

Operators should evaluate all newly constructed wells for a secondary barrier envelope. While these barrier elements are not routinely exposed to reservoir fluids, they should be rated to withstand them.

Examples of some of the secondary barrier elements that make up the secondary well barrier envelope are as follows:

— production casing, if well has tubing and packer as primary barrier;

— production casing, if well was designed with a cemented full liner as primary barrier;

— surface casing;

— intermediate casing;

— surface wellhead valves/safety valves; and

— cement.

6.5.4 Barrier Evaluation

Secondary barrier envelope evaluation should be site-specific and risk based. A risk-based determination for new wells may include reviewing and documenting the following:

— quality of barriers using but not limited to corrosion logs, pipe integrity logs, cement bond logs, leak detection logs, pressure tests, and other similar barrier examination tools and techniques;

— wellbore configuration's ability to contain fluids throughout storage cycles without any leaks in containment;

— deliverability/reliability impairments due to installation of secondary well barriers and the risks associated with restoring that deliverability elsewhere (i.e. new drills, sophisticated stimulation techniques);

— added risks created by installation and servicing requirements of added tubulars;

— consequences of well containment failure (see Section 8, Table 1 Category—Wells); and

— proximity to neighborhoods, schools, and other populated areas.

6.6 Completion and Stimulation

6.6.1 General

The operator shall design and conduct well completion and stimulation in a manner that avoids 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.

6.6.2 Baseline Logging

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

6.6.3 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.

NOTE For additional guidance, see API Guidance Document HF1 [15], API Guidance Document HF2 [16], API Guidance Document HF3 [17], and API Recommended Practice 100-1 [36].

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 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 and other logging techniques in the fracture-treated well and nearby wells after the job to determine fracture location indications; and

— post-treatment gas detection logs of the fracture-treated well and nearby wells to investigate gas saturations behind casing and detect apparent change in saturation, if any.

6.7 Well Remediation

6.7.1 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. Below are potential responses to a well identified as having compromised mechanical integrity.

— shut-in or temporary abandonment of the well;

— remediation to restore well integrity;

— reconfiguration to different service;

— permanent abandonment with adequate provisions to prevent flow following the abandonment.

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

6.7.2 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.

Existing single or multiple barrier wells, in some circumstances, can be improved prior to returning the well to operating condition. Existing wellbore integrity should be evaluated prior to initiating the remediation to ensure that the intervention procedure itself does not result in a failure of the existing barrier envelope. If the risk of failure during the intervention is too great to meet the operator’s risk tolerance, the remediation should not be attempted. Below are some potential remediation methods:

— perforate and block squeeze to place a permanent material, such as cement or resin, into the annulus behind casing

— circulating squeeze to place permanent material, such as cement or resin, behind the casing

— casing patch across section of weakened casing

— solid expandable liner

— running and cementing a new casing string inside of the existing casing

— installing a packer completion

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.

6.8 Well Closure (Plugging and Abandonment)

6.8.1 General

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

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

6.8.2 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 Specification 10A [9] and ASTM C150/C150M [10] 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.

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 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 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.

6.8.3 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.

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.

6.9 Environmental, Safety, and Health

6.9.1 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 Recommended Practice 49 [20], API Recommended Practice 51 [2], API Recommended Practice 54 [21], and API Recommended Practice 76 [3] 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 to protect the environment and the safety and health of workers and the public.

6.9.2 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 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 10.4 prior to beginning operations or well work activities.

6.10 Testing and Commissioning

6.10.1 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.

— for new well construction, the production casing shall be tested prior to drilling out the shoe, considering the cement design factors so that this test does not compromise the cement integrity.

— 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.

— 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.

6.10.2 Casing Inspection Logging

The operator should perform baseline casing inspection logging on new production casing.

6.10.3 Well Conversion to Storage Service

When converting to storage service, the condition of accessible tubulars and cement shall be evaluated to determine capabilities of containing formation pressures and providing zonal isolation of the storage reservoir. Wellhead assembly equipment shall be rated to or above the maximum anticipated surface pressure. If a well is abandoned, see 6.8 for guidance.

6.11 Monitoring of Construction Activities

6.11.1 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.

6.11.2 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 6.12.

6.11.3 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 11.11.

6.11.4 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 or/and engineering characterizations as outlined in 5.2 and 5.3.

6.12 Recordkeeping

6.12.1 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.
  - 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.
  - Detailed laboratory reports
  - Simulation reports
- 6.6 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.
- 6.7 Well Remediation
  - Cementing reports (as detailed in 6.4).
  - Type of equipment used and location in well.
  - Well logs.
  - Workover and recompletion reports.
- 6.8 Well Closure
  - Equipment removed from well.
  - Cementing reports (as detailed in 6.4).
  - Plugging records.
- 6.10 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.
- 6.11 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, MWD logs, and mud logs.

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

6.12.2 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.

6.12.3 Well Schematics

Creating and maintaining well schematics allows for quick access to critical well information during storage operations. The operator should maintain a wellbore schematic. As applicable and available, the wellbore schematic may include, but not limited to:

— well name;

— operator;

— API number;

— location;

— casing details;

— cement tops;

— ID restrictions;

— open perforations;

— squeezed perforations;

— key formations;

— total depth; and

— plugback depth.

As applicable and available, the operator should maintain a completion schematic. This may include, but not limited to:

— packers (size, make, model, type, location, dimensions);

— nipples (size, make, model, type, location, dimensions);

— blast joints; and

— SSSV (size, make, model, type, location, dimensions).

As applicable and available, the operator should create and maintain a wellhead schematic. This may include, but not limited to:

— well name;

— operator;

— API number;

— location;

— details on each component (PSL level, make, model, trim, flange details);

— named annuli; and

— penetrations for control line.

As applicable and available, the operator should create and maintain an abandoned wellbore schematic. This may include, but not limited to:

— well name;

— operator;

— API number;

— location;

— casing in well;

— casing cut off depth;

— cement plugs;

— cement records;

— open perforations;

— squeezed perforations;

— mechanical plugs or retainers; and

— TD.

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 or total capacity.

NOTE Section 8 assists the operator in characterizing risk related to reservoir and well development and commissioning. 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 to allow identification of anomalous conditions during commissioning and operation.

7.2.2 Integrity Assurance

Mechanical integrity tests and/or mechanical condition evaluation shall be performed prior to project commissioning to verify that each well can meet the designed operating conditions. Requirements related to well mechanical integrity testing are covered in 6.10.

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 6.8.

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 changes incorporated to the preventive and mitigative measures being used. Potential commissioning risks related to reservoir integrity, as identified by the risk assessment in Section 8, shall be monitored along with the effectiveness of the associated preventative and mitigative measures in maintaining storage functional integrity.

7.3.2 Monitoring and Analysis Methods

Average reservoir pressure versus inventory shall be monitored and compared with expected conditions 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 considered when using observation wells. Inventory assessments, as presented in 9.5, shall be conducted to confirm inventory.

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.

7.4 Mechanical Integrity Monitoring

7.4.1 General

The potential commissioning risks to mechanical integrity identified by the risk assessment in Section 8 shall be monitored along with the effectiveness of the associated preventive and mitigative measures in maintaining storage functional integrity.

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, calipers, 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:

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

— well testing records and records of well actions taken during commissioning; and

— 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 that includes the underground gas storage reservoir, all wells associated with the reservoir, the areas of review and buffer zones, but excludes pipelines and compressor stations. Figure 2 has been incorporated to provide an operator with an overview of a Risk Management Program and process as contained in this section.

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

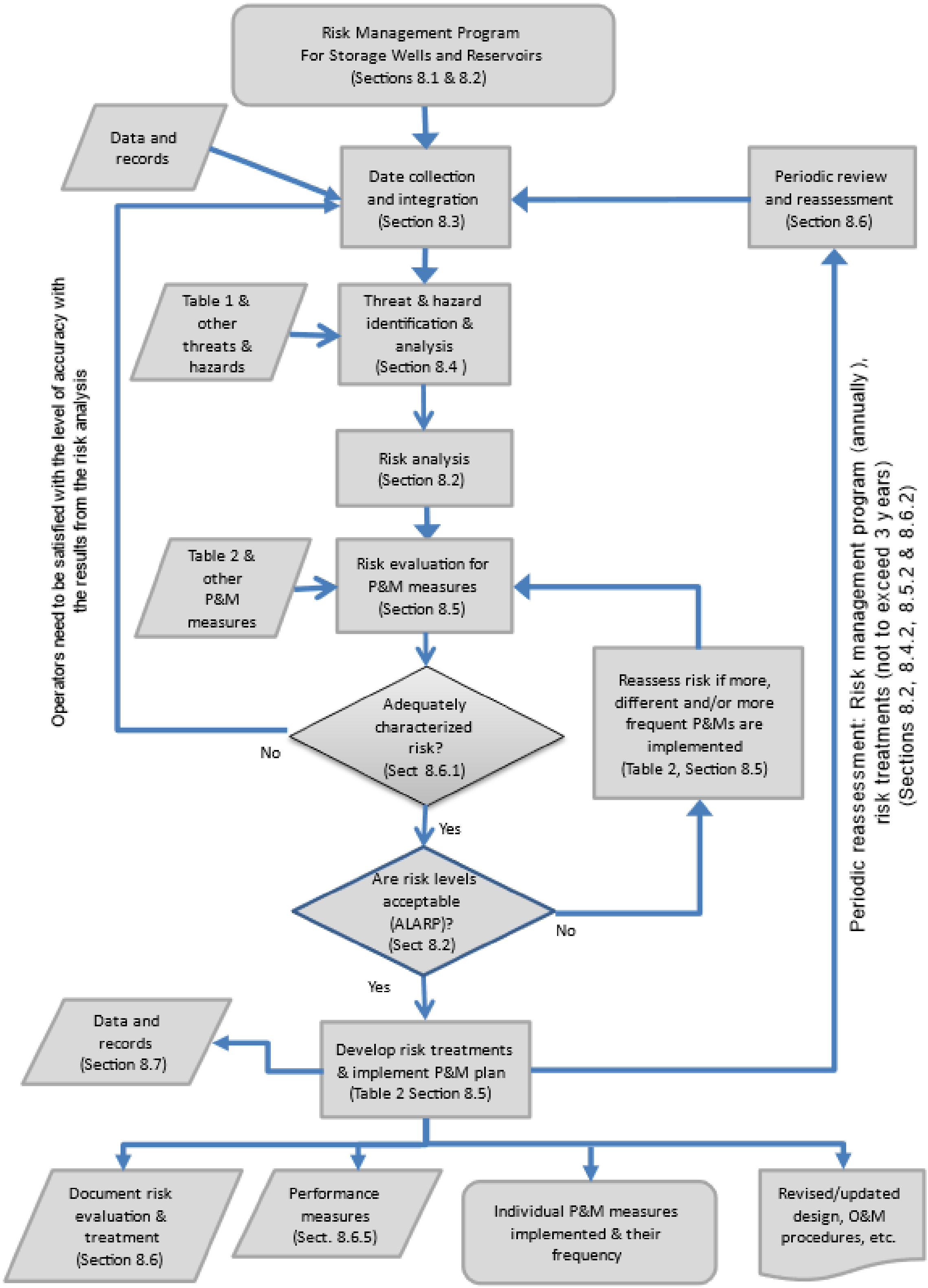

Figure 2—Risk Management Program Flowchart

8.2 Risk Management Program

The operator shall develop, implement, and document a program to manage risk that includes:

— data collection;

— potential threats and hazards;

— risk assessment;

— preventive and mitigative measures;

— periodic review; and

— record keeping.

Operator shall conduct an annual review of the risk management program.

The operator should follow the process of ALARP (as low as reasonably practicable) or equivalent risk reduction protocol, as a technique of risk management in the areas of facility design, construction, operation, and decommissioning.

8.2.1 General

Risk assessment is the overall process of risk identification, risk analysis and risk evaluation that ultimately leads to managing risk. It uses a variety of tools and techniques that evaluate and prioritize risks to direct risk management activities toward promoting functional integrity of the storage operation, recognizing that the storage facility and operation can impact, or be impacted, by its own operation or non-associated third-party activities within the areas of review or buffer zones.

The operator shall assess risk related to the storage operation and third-party activities within the areas of review, and buffer zones using a consistent process.

The operator shall define the roles and responsibilities of those involved in the managing of the risks.

8.2.2 Risk Assessment Process

A risk assessment method shall minimally include the following steps:

— identification and collection of information relevant to the storage field as part of risk assessment (data collection)

— identification of potential threats and hazards (Table 1) to the storage facility from within the areas of review and buffer zone (risk identification);

— evaluation of the likelihood of events and consequences related to the events (risk analysis);

— determination of risk ranking to develop P&M measures (Table 2) to monitor and/or reduce risk (risk evaluation);

— documentation of risk evaluation and decision basis for P&M measures (record keeping);

— periodic evaluation of risk assessment and determination of need to escalate the implementation or modification of P&M measures;

— evaluation of risk management program using performance measures.

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 integrity monitoring and field history to determine susceptibility to threat and hazard-related events and to assess threat and hazard interaction.

The operator should identify data sources to be used in the risk analysis. Examples of data may include:

— reservoir studies;

— drilling and workover records;

— material records;

— well and reservoir performance data;

— well logs;

— published industry; and

— research information

The operator should validate identified data used in the risk analysis to ensure data accuracy.

The operator should establish the process for retaining data until the next risk analysis is performed.

There can be additional risk introduced into the risk assessment when there is a lack of records regarding well and reservoir integrity on one or more well or reservoir attributes. Operators should account for this in their risk assessments.

8.4 Threat and Hazard Identification and Analysis

8.4.1 General

The section discusses the common threats and hazards associated with gas storage operations. Operators shall identify those threats and hazards which may impact the functional integrity of the operations. Those identified threats and hazards shall be included in the operator's risk assessment process.

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 from the risk assessment. A lack of data or information should not be used as justification to exclude a specific threat.

8.4.2 Analysis of Threats and Hazards

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 use data and records to ensure that all known threats and hazards have been considered for inclusion in the analysis.

The operator should incorporate the operating history of the wells and reservoirs in the risk analysis to ensure that all known threats and hazards have been considered for inclusion in the analysis.

The operator should estimate the risk to wells and reservoirs based on threats and consequences of failure annually and consider changes to risk, including changes in threats, likelihood of failure, and consequences of failure.

The risk assessment should address not only individual threats, but also potential threat interactions, such as casing damage during service work that could exacerbate internal corrosion threat.

Table 1—Potential Threats or Hazards 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 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, lack of records on existing or plugged wells, etc.	— Release of gas to the atmosphere and environmental hazards — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources or wells — Loss of stored gas inventory — Decrease or loss of field performance
	Wells, operation, and maintenance activities	— Inadequate procedures — Failure to follow procedures — Inadequate training — Inexperienced personnel or supervision — Use of incorrect data to perform a field operation	— 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 or wells — Decrease or loss of field performance — Getting tool stuck in hole — Exceeding pressure limitations
	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 — Loss of well control as a result of not having full bore valve during well intervention — Loss of well control during well intervention/workover/snubbing operations — Decrease or loss of field performance — Loss of well

Table 1—Potential Threats or Hazards and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Wells	Third-party damage (intentional/ unintentional damage)	Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage facilities	— Loss of ancillary facilities — Well on/off status change — Impact to service reliability — Damage to wellsite facilities and equipment — Safety hazard to company personnel and the public — Loss of stored gas inventory
	Outside force— natural causes	Weather related and ground movement	— Weather conditions, earth movements, groundwater table changes, subsidence, etc. that could result in: — Damage to facilities/impact to service reliability — Loss of stored gas inventory
Reservoir	Third-party damage (third- party well operations, subsurface encroachment)	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 is not as high as storage pressure — Inability to meet design performance requirements — Damage to third-party/public property and personnel
	Pressure and Volume Limits	Effective geological containment becoming ineffective at pressures higher than the original discovery pressure	— Lateral or vertical loss of stored gas inventory — Safety and environmental hazard to company personnel and the public — Inability to meet design performance requirements
		Exceeding maximum/minimum pressure or volume limits, faulty operating practices	— Loss of stored gas inventory — Safety and environmental hazard to facilities, company personnel and the public

Table 1—Potential Threats or Hazards and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Reservoir	Geologic Uncertainty	Uncertainty of lateral 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
		Subsidence	— Loss of stored gas inventory — Damage to casing, surface piping equipment and third party/public property
		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 vertical containment of storage gas (caprock or bounding faults)	— 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 or pipeline repairs/failures

Table 1—Potential Threats or Hazards and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Surface	Third-party damage (surface encroachment)	Surface encroachments restricting operations or facility integrity	— 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
	Intentional/ unintentional damage	Damage to surface equipment by accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism, etc.	— 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	— Hazardous weather conditions, earth movements, groundwater table changes, subsidence, etc. that could result in: — Damage to facilities/impact to service reliability
	Flammables on wellsite	A source of fuel for combustion that may either damage a well or be an additional fuel source for an ongoing well incident	— Safety and environmental hazard to personnel and public — Damage to company facilities — Risk of a minor integrity incident escalating into a major event

8.5 Preventive and Mitigative Measures

8.5.1 General

Preventive and Mitigative (P&M) measures are actions conducted by the operator to monitor and/or 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 can include programs, methods, tools, or routine condition monitoring activities to monitor and manage risk. Examples of P&M measures for storage activities are listed in Table 2.

8.5.2 Development and Use of Preventive and Mitigative Measures

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.

8.5.3 Training

The operator should train their personnel on the procedures related to the P&M measures (see 11.11). The operator can apply these P&M measures to individual wells, individual reservoirs, or fields, or groups of wells or fields.

Table 2—Preventive and Mitigative Measures

Category of Review	Threat or Hazard	Preventive/Mitigative (P&M) Measures 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; 6.10
		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; 6.8; 7.4, 9.3, 9.4
		Monitor annular pressures, rates, gas composition or temperatures	6.6; 7.2; 9.3; 9.4; 9.6
		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	6.2; 9.3
	Design	Collect and evaluate plugged and abandoned well records and rework or plug	5.3; 7.2; 6.8; 9.3
		Develop design standards for new wells	6 (all except 6.7 and 6.8)
		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
		Establishment and implementation of Procedures	11.2
	Operations and maintenance activities	Establishment and implementation of procedures.	6.11; 11.2
		Training of personnel and contractors	11.11; 6.11
		Implement site specific training and safety plan programs for company and contractor personnel	11.11; 10.4 (for emergency response training)
	Well intervention	Develop detailed drilling and well servicing procedures	6.7; 11.4
		Install protection equipment (e.g. fences, alarms, etc.) for site security and safety	6.2; 10.2
	Third-party damage (intentional/unintentional)	Include storage facilities into the corporate security plans	10.2; 10.4;11.2
		Develop storage well control plan	10.4
		Monitor third-party drilling permits and well operations	9.4
	Outside force—natural causes	Develop site-specific operating plans for known problems such as areas prone to flooding, earth movements, river/stream bed movement, and other natural causes	5.5; 9.2; 10.3
		Monitor areas prone to flooding, earth movements, river/stream bed movement, and other natural causes for impacts on nearby well sites	6.9; 10.3; 10.4
		Plug and abandon impacted wells and drill replacement in more stable location	6.8; 6.11

Table 2—Preventive and Mitigative Measures (Continued)

Category of Review	Threat or Hazard	Preventive/Mitigative (P&M) Measures or Monitoring Programs	Reference Location(s) of Program in API 1171
Reservoir	Third-party damage (third-party well operations)	Verify compliance with 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
		Attempt to establish 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	11.9
		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
	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 area of review and buffer zone, (vertical and horizontal) and update as necessary	5.2; 5.3; 9.4.
		Conduct semiannual tests for inventory verification	9.5
		Establish observation wells based on evaluation of need	5.4; 9.4
		Review records of plugged and abandoned wells	9.3
	Pressure and volume limits	Collect and review existing regional geological studies and data	5.2.2
		Monitor field behavior at pressures higher than discovery pressure for deviation from projection	7.3.2; 9.5.5; 9.7
		Monitor daily injection/withdrawal volumes, and inventory	9.5; 9.6

Table 2—Preventive and Mitigative Measures (Continued)

Category of Review	Threat or Hazard	Preventive/Mitigative (P&M) Measures or Monitoring Programs	Reference Location(s) of Program in API 1171
Reservoir	Reservoir fluid compatibility issues	Conduct fluid compatibility studies on samples of the reservoir rock 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
	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; 10.4
Surface	Third-party damage (surface encroachment) Third-party damage (intentional/unintentional damage)	Work with landowners, local officials, and others on the surface operating requirements around storage wells	11.9
		Use of existing public awareness activities required for pipelines	11.9
		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) Outside force—natural causes	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	10.4; 11.2
		Develop storage well control plan	10.4
		Liaison with local, state, and federal law enforcement agencies	10.4
		811 Call-Before-You-Dig programs (damage prevention program)	11.9
	Outside force—natural causes	Perform routine patrols and surveillance, and event- specific surveillance activities	10.3
		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	10.3; 10.4
		Develop site-specific operating plans for known problems such as areas prone to flooding, earth movements, river/stream bed movement, and other natural causes	5.2; 9.2; 10.3
		Monitor areas prone to flooding, earth movements, river/stream bed movement, and other natural causes for impacts on nearby well sites	10.3; 10.4
		Plug and abandon a well and drill replacement in more stable location	6.8; 6.11
		Remote control capabilities	6.2
	Flammables on well site	Review needed for flammables on site	10.2.7
		Develop site-specific plan for ignition sources and flammables during well work and operations	10.2.7

8.6 Periodic Review and Reassessment

8.6.1 General

The operator shall assess the performance of the risk management program against goals and objectives as defined by operator.

The operator shall review the results of the risk assessment process to determine whether the risk assessment, resulting prioritization or ranking represents its facilities and adequately characterizes the risks.

The operator shall review the results of P&M measures to determine the success of managing risk based on site-specific conditions.

8.6.2 Frequency

The operator shall define the interval of review and identify any new threats or hazards.

The interval should be of sufficient length that the quantity of new data and information that is brought into the analysis is meaningful and that any developing trends have sufficient data to be identifiable.

The operator shall define a review frequency for the P&M measures, not to exceed three years.

8.6.3 New Threats and Hazards

If new threats or hazards are identified, or the impact of existing 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.

8.6.4 Evaluation Team

The operator should use a multi-disciplinary team for the review of the risk management program and performance of the risk assessment process and P&M measures. Members of the team should be trained and familiar with the risk management program and its operation.

8.6.5 Performance Measures

The operator shall use performance measures to assess the risk management program.

Performance metrics tailored to the specific needs of the facility and operator should analyze such factors as integrity performance, the number and types of issues that are occurring, threat and hazard impact, P&M measures and monitoring program selection and success, established threshold exceedances, as well as other conditions, which may be used to determine if elements of the risk management program need update or revision based on risk trends. Examples of leading and lagging performance measures may include:

— Leading:

  — established P&M measures are up to date;

  — well and risk documentation is maintained and current;

  — P&M measures completed to operator defined plan frequency.

— Lagging:

  — number and trend of P&M measures changes;

  — number and trend of threshold or condition exceedances;

— number and trend of escalations needed based on P&M measure inspection results.

8.7 Recordkeeping and Documentation

The operator shall develop a risk management records retention plan.

Risk management documentation can include data used during the risk assessment, P&M measures employed, and the 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

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.

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

9.2.1 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, 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 well, including each third-party well, where possible, that penetrates the storage reservoir and buffer zone, or areas influenced by storage operations. The evaluation depends upon a variety of factors, including but not limited to, available data, well type, ownership, and status.

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.

Data for evaluation of active third-party wells shall be requested from third-party operator and should be requested from public sources. Public sources can include state and historical preservation office databases. Evaluation of third-party wells follows the frequency as determined using the risk assessment.

The operator should identify the recorded location of plugged wells that penetrate the storage reservoir, within the buffer zone, or area of review using third-party or public records.

Active well mechanical integrity evaluations shall include initial and subsequent evaluations at a frequency 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 gas in all accessible annuli at a frequency determined by the risk assessment or at a minimum annually. If an annulus is not accessible, the operator shall determine an enhanced monitoring plan or remediation plan and the timeline to implement either or both.

The operator shall evaluate each annular gas occurrence that exceeds operator or regulatory-defined threshold levels determined from industry standards, well integrity evaluations or the risk assessments.

NOTE For additional detail see API Recommended Practice 90-2 [38].

The operator shall inspect the wellhead and well site for leaks and condition at least annually. Visual inspections may include, but are not limited to:

— identifying mechanical or corrosion damage,

— gas leaks from wellhead assembly and surrounding wellsite,

— missing equipment (valve handles, control line piping, gates, or signage), and

— encroachment activities.

The operator shall annually conduct the following:

— function test the operation of the master valve and pipeline isolation valve(s) by fully opening and closing the valves; and

— confirm the ability of the master valve and all isolation valve(s) to isolate the well from pipeline. The confirmation may be accomplished with noise or temperature surveys, pressure differential or other methods that do not require gas to be vented to the atmosphere.

All valves shall be maintained, repaired, or replaced in accordance with the operator's valve maintenance program.

Surface and subsurface safety valve systems, where installed, shall be function-tested on an annual, not to exceed 15 months frequency, or in accordance with manufacturer's recommendations and the operator's procedures.

NOTE API Standard 6AV2 [39] addresses testing and acceptable leak rate of valves.

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 shall verify the integrity of the production casing by pressure testing or corrosion logging at a frequency determined by the risk analysis. When the latter is used, then the operator shall evaluate areas of apparent metal loss and the impact on the allowable operating pressure.

Corrosion potential can be assessed by evaluating the impact of the following as applicable and available:

— wellbore produced fluids and solids;

— annular and packer fluids; and

— current flows associated with cathodic protection systems.

Where a baseline gas detection log has not been run the operator should obtain a gas detection log on each well for use in detecting changes in gas indications behind casing throughout the wellbore over the life of the well.

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 and Engineering 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). The operator should review, and update reservoir engineering characterizations as new data become available (see 5.3 for additional information on engineering 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 trends, 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.

9.4.4 Observation Wells

The operator should use observation wells around, above, or below the reservoir to monitor pathways of potential communication 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 and 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 shall perform material balance studies using representative average reservoir pressure and inventory data. The data should be collected during semiannual low- and high-pressure surveys (generally in the spring and fall, per Section 8, Table 1). The trends developed from the material balance should be evaluated for indication of gas migration.

The operator can also monitor pressure inventory hysteresis trends for indication of gas migration.

9.5.4 Aquifer Reservoir Methodology

For an aquifer storage reservoir or converted depleted hydrocarbon reservoir with a strong water drive, the operator shall use inventory assessment methods based on reservoir operating characteristics. Methods can include but are 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;

— performing gas pore volume calculations;

— reservoir simulation; or

— logging.

NOTE Aquifer storage reservoirs operate at pressures above and below aquifer pressure, resulting in water efflux and influx, and changing gas reservoir size. Semiannual surveys are often not effective in inventory assessment for aquifer storage reservoirs. 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 shall account for measured and unmeasured storage gas inventory changes such as injections, withdrawals, fuel, operations, losses, or other uses.

The operator shall calibrate pressure gauges used for inventory management 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 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, 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, Pressure, and Inventory Monitoring

9.6.1 General

The operator shall monitor total reservoir injection and withdrawal flow rates as well as flowing pressures, shut-it pressures and inventories. The operator should evaluate this data for indications of reservoir integrity or loss thereof.

The operator can monitor well injection and withdrawal flow rates as well as flowing pressures and shut-in pressures. The operator should evaluate this data for indications of well integrity or loss thereof, where available.

9.6.2 Deviations

Deviations from expectations that might indicate potential wellbore or reservoir integrity issues should be documented for further investigation and remediation as appropriate.

9.6.3 Flow Erosion

The operator should assess the potential for flow erosion due to velocity and sand content of the gas stream. Options may include but are not limited to reviewing well completion techniques and operational problems, core sample analysis of grain cementation, sand flow indicators at wellheads, coupons in well flowlines, and inspections of well site meters, separators, flow control valves for signs and sand or erosion. The operator should monitor casing and wellhead component wall thickness at facilities where the conditions are suitable for erosion to occur at a frequency determined by the risk assessment.

9.7 Integrity Nonconformance and Response

The operator should address and document nonconformance regarding design criteria for well and reservoir integrity. Abnormal operating conditions encountered, or anomalies discovered, and actions taken to address each occurrence should be documented.

If a well is determined to have compromise integrity, see 6.7.

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 integrity demonstration, verification, and monitoring records for the life of the facility.

10 Site Security and Safety Programs

10.1 General

This section provides guidance that will assist operating personnel in recognizing and responding to abnormal conditions so that life and property can be protected. The elements in this section are site specific and therefore will vary based upon such conditions as population proximity and density, natural forces, well(s) flow potential, vandalism, terrain, adjacent land use, and the environment that could be possibly impacted by the facility operation and emergencies related to the facility.

NOTE For reference, API Recommended Practice 1173 [42] provides relevant information to site security and safety processes and procedures.

10.2 Site Security Processes and Procedures

Site security and safety processes and procedures shall be developed to mitigate operational safety hazards and risks (as identified in risk identification process, see Section 8). Safety programs should include facility safety, staff safety, contractor safety, and public safety. These security and safety processes and programs should be coordinated with associated pipeline programs, as applicable.

10.2.1 Access Control

Access control is commensurate to the risk and consequences of the well(s). This can include automatic gate, keypads, call buttons, badge readers, and cameras. These devices allow the remote monitoring and control of access points throughout the facility.

The use of guard stations or controlled access points should be evaluated if any part of the facility has an unusual amount of personnel or equipment, such as during out of ordinary construction or maintenance operations. Personnel entering or leaving should be logged so that a record of those on-site is maintained for both security and safety reasons and in case an emergency arises.

Other considerations to control access are facility lighting, wellhead enclosures, and wellhead valve security.

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

10.2.2 Emergency Assembly Area

A designated assembly area shall be identified for employees, contractors, and visitors to proceed to in the event of an emergency during well work activities. The location of this emergency assembly area shall be identified to all employees, contractors, and visitors on site prior to the performance of any work. Sign in sheets or similar can be used to account for contractors and visitors in case an emergency arises.

The use of windsocks dependent upon terrain, prevailing weather and gas composition may be used to determine appropriate location.

10.2.3 Communications

Operators should have a means of communication or an alert system for operations personnel. This can include a phone system, radios, or cell phones.

10.2.4 Safe Work Practices

The operator shall maintain procedures that address safe work practices to ensure the safe conduct of operating, maintenance, and emergency response activities that impact underground gas facility safety.

10.2.5 Well Identification

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

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

— operator name; and

— operator's 24-hour emergency contact number.

NOTE Signage requirements vary depending upon the jurisdiction.

The operator can add other information or signage to enhance facility or site security and safety such as additional information regarding the location or warnings for areas containing potentially hazardous, flammable, or noxious vapors.

10.2.6 Well Site Barriers

Well site barrier (e.g. jersey barriers, bollards, fencing) use, as determined by risk assessment, should be installed around wellheads and other critical facilities to prevent accidental or intentional damage by vehicles and equipment. These barriers should be removable to provide space for maintenance or workover equipment.

10.2.7 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 Site Inspections

10.3.1 General

Site inspections for review of safety and security assurance shall be performed to verify that requirements Section 10 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.

10.3.2 Procedures

The operator shall develop and implement site safety and security inspection procedures. Procedures should include:

— purpose of the inspection;

— 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;

— risk identification of hazards and potential threats; and,

— documentation, reporting, and recordkeeping requirements.

10.4 Emergency Preparedness/Emergency Response

10.4.1 General

Operators shall develop emergency response plans (ERP) to provide for the safe operation, control, and management of the storage facility in the event there is an emergency condition. These should be coordinated with associated storage or pipeline facilities, as applicable. The safety of life, property and the environment should be the primary goal of these plans. Operators shall integrate underground gas storage emergency procedures with required regulatory procedures where possible and applicable. The plans shall include processes and procedures that address accidental releases, equipment failures, natural disasters, and third-party emergencies.

10.4.2 Emergency Response and Emergency Response Planning

The ERP shall contain, at a minimum, the following elements:

— determination and planning for potential types of emergencies;

— communication plan: internal and external protocols;

— identification of response resources and interfaces, including local emergency responders;

— recognition and use of Unified Command/Incident Command Structure or similar protocol with roles, responsibilities, and administrative details;

— incident management: safety, health, and environmental protection processes; and

— training, exercises, and drills to include frequency (external agencies and organizations can be included):

  — These exercises shall be evaluated against ERP goals and objectives and documented, including lessons learned.

The plan shall be reviewed at least annually, not to exceed 15 months.

NOTE 1 Potential types of emergencies may include spills, releases, natural disasters, security threats, fires, explosions, utility loss, pandemics, medical emergencies, or civil disturbances.

NOTE 2 Training, exercises and drills may include tabletop exercises, workshops, testing, specific functional drills or full-scale exercises

10.4.3 Well Control Plan

The operator shall have a Well Control Plan (WCP) whether it is contained within the ERP or as a standalone document. The uncontrolled release of gas and management thereof from an underground gas storage well shall be addressed. The primary goal of a WCP is to protect life, property, and the environment.

WCP’s are operator specific and proper risk assessments should indicate any needs for well specific issues to be addressed. WCP’s should include, at a minimum, the following elements.

— Well drilling, intervention, or workover planning considerations such as an anticipated pressures, well control, access to current wellbore schematics, and other site or formation specific drilling or workover hazards;

— Communications, event organizational structure, roles/responsibilities;

— Event site safety, security, and procedures;

— Required materials and services;

— Event response drills and exercises; and

— Training that ensures adequate knowledge and demonstrates competency.

10.5 Cyber Security

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

NOTE API Standard 1164 [40] can be referenced for further guidance.

11 Procedures and Training

11.1 General

This section addresses requirements for the development, implementation, and maintenance of programs, plans, and procedures intended to guide the operator safely and effectively 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 natural 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.

11.2 Management of Procedures

11.2.1 Construction, Operation, and Maintenance Procedures

The operator shall develop and follow procedures for the 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 personnel 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. 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.

NOTE The operator likely already have in place procedures for operation and maintenance, emergency response, integrity management, control room communications, public awareness and damage prevention, qualification of personnel, management of change (MOC), and other procedures covering pipeline facilities.

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 frequency determined by the operator. 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 specified in 11.10.

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 natural gas storage wells and reservoirs facilities 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 8.5), recognition of abnormal operating conditions, and the associated schedules and recordkeeping requirements. The procedures should address indications and 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.

11.4 Well Work

11.4.1 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.

11.4.2 Scope of Procedures

The operator's established procedures should define minimum safety requirements for surface equipment, pressure control equipment, downhole operations, MOC processes, and other requirements as specified by 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 Standard 53 [28] and API Recommended Practice 54 [21] 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 11.11).

The operator should require a person who is trained 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 Other Well Entry and Well Operation Procedures

11.5.1 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.

11.5.2 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 Recommended Practice 54 [21] 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:

— well configuration and completion details;

— characterization of the stored hydrocarbons and the presence of H_2S or other hazardous or corrosive agents;

— anticipated wellbore and storage zone pressures and temperatures;

— anticipated presence of water, fluids, deposits, or scale and restrictions in the wellbore;

— safety requirements as outlined in 11.8; and,

— reporting requirements.

11.6 Interaction with Control Room

11.6.1 General

Storage personnel shall be responsible for preparing and communicating guidelines for maintaining reservoir and well functional integrity.

11.6.2 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 to maintain reservoir and well integrity during normal, abnormal, and emergency conditions.

11.7 Integrity and Risk Management

11.7.1 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.

11.7.2 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 Safety and Environmental Programs

11.8.1 General

The operator shall maintain programs that incorporate safeguards to the environment, site security, and safety and health prior to beginning storage design, construction, operations, and decommissioning that are founded upon industry recommended practices and nuances of their facilities and operations.

11.8.2 Scope of Programs

The programs can include elements, such as:

— Operational controls—safe work practices, system integrity, MOC, contractors, and incident investigation;

— Safety assurance—audit, goals and objectives, evaluation of safety culture;

— Management review and continuous improvement;

— Competence, awareness, and training;

— Documentation and record keeping; and

— Other elements 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.

11.9 Public Awareness and Damage Prevention

For further information on public awareness programs, see API Recommended Practice 1162 [41].

11.10 Management of Change

11.10.1 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.

11.10.2 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.

11.11 Training

11.11.1 Training Requirements

The operator shall provide training for personnel responsible for operating, maintaining, and monitoring natural gas storage wells and reservoirs facilities 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.

The operator should review training programs periodically, such as when changes occur in technology, processes, procedures, or facilities.

11.11.2 O&M Personnel

The operator should confirm by training and testing those persons assigned to operate and maintain natural gas storage wells and reservoirs possess the knowledge and skills necessary to carry out their duties and responsibilities including those required for start-up, operation, and shutdown of natural gas storage wells and reservoirs. Training may consist of, but not limited to:

— site-specific procedures necessary for operation;

— recognition of abnormal operating conditions;

— reporting, 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 natural gas storage wells and reservoirs.

The operator should provide refresher training on a periodic basis for personnel on current operating procedures.

11.11.3 Supervisory Personnel

Specific job requirements may require the company person or persons (supervisors) directly responsible for the work being performed to be located on site while the work is being conducted (see 6.11.3). Personnel acting in supervisory roles should be trained to provide competent and effective supervision of the operations being carried out. Supervisor responsibilities should include, but not limited to, the following:

— confirm that personnel on site can recognize abnormal operating conditions and applicable hazards and know their role in safety and emergency procedures;

— confirm that operating and contractor personnel conducting gas storage well operations possess or are working under the supervision of someone who possesses, the knowledge and skills to safely perform the work;

— confirm that operating and contractor personnel understand and adhere to reporting requirements in the operator's procedures.

11.11.4 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 undertake the following, but not limited to:

— provide and specify the scope of work to be performed by contractors;

— 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;

— confirm that contractor personnel conducting gas storage well work possess or are working under the supervision of someone who possesses, the knowledge and skills to safely perform the work;

— 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;

— provide training to contracted personnel that includes applicable site-specific safety procedures, rules pertaining to the facility, reporting requirements, and the applicable provisions of emergency action plans.

11.12 Records

11.12.1 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.

11.12.2 Training Records

The operator shall maintain records that demonstrate compliance with this subsection. Company personnel training records should include:

— identification of the trained individual;

— identification of the training and methodology of training provided; and

— date(s) training was completed by the individual.

The operator should retain documentation of the contractor training review (see 11.11.4).

11.12.3 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 but not less than five years.

Annex A
(informative)

Tubular Connection Types and Features

Table A.1 provides operators a cross reference of features for connections commonly used in downhole tubulars.

Table A.1—Tubular Connection Types and Features

	API	Semi-premium (Proprietary)	Premium (Proprietary with Metal-to Metal seal)
Thread Form	LTC, STC, Buttress	Proprietary (mostly modified buttress)	Proprietary (mostly modified buttress)
Seal Mechanism	Thread contact stress and thread dope	Thread contact stress and thread dope	Metal-to-metal seal(s)
Sealability	LTC, STC: Moderate Buttress: Low	Low – High	Highest
Tensile Strength	LTC, STC: Low Buttress: High	High (for modified buttress threads)	High (for modified buttress threads)
Make-up Torque	Refer to API Recommended Practice 5C1	Manufacturer Specification	Manufacturer Specification

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