CSA Z741-11

Geological storage of carbon dioxide
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1 Scope

1.1
This Standard is intended to establish requirements and recommendations for the geological storage of carbon dioxide. The purpose of these requirements is to promote environmentally safe and long-term containment of carbon dioxide in a way that minimizes risks to the environment and human health. This Standard is primarily applicable to saline aquifers and depleted hydrocarbon reservoirs and does not preclude its application to storage associated with hydrocarbon recovery. This Standard includes, but is not limited to, the safe design, construction, operation, maintenance, and closure of facilities and storage sites. This Standard also provides recommendations for the development of management documents, community engagement, risk assessment, and risk communication. This Standard recognizes that site selection and management are unique for each project and that intrinsic engineering risk(s) and uncertainties will be dealt with on a site-specific basis.

1.2
This Standard applies to a carbon dioxide (CO₂) stream. Depending on the storage unit, the stream could be considered to contain impurities for which health, environmental, and safety risks require proper evaluation. This Standard does not permit waste and other matter to be added for the purpose of disposing of the added waste or other matter. However, a CO₂ stream can contain incidental associated substances from the source, capture, or injection process and/or trace substances added to assist in CO₂ migration detection.

1.3
The project life cycle covers all aspects, periods, and stages of the storage project, beginning with those necessary to initiate the project (including site screening, characterization, assessment, selection, engineering, permitting, and construction), that lead to the start of injection and proceeding through subsequent operations until cessation of injection; and culminating in the post-injection period, which can include a post-injection closure period and a post-closure period. This Standard specifies that the post-closure period occurs only if a transfer of responsibility and liability to a designated authority or other responsible entity takes place. If a transfer does not occur, the project remains in the post-injection closure period and formal site closure does not occur. This Standard does not specify post-closure period requirements. Figure 1 illustrates the confines, limits, and boundaries of this Standard.
This Standard does not apply to
(a) the post-closure period;
(b) CO₂ injection and storage in unmineable coal beds, basalt formations, shales, and salt caverns; and
(c) underground storage in materials involving the use of any form of containers.

1.4
In CSA Standards, "shall" is used to express a requirement, i.e., a provision that the user shall satisfy in order to comply with the standard; “should” is used to express a recommendation or that which is advised but not required; “may” is used to express an option or that which is permissible within the limits of the standard; and “can” is used to express possibility or capability. Notes accompanying clauses do not include requirements or alternative requirements; the purpose of a note accompanying a clause is to separate from the text explanatory or informative material. Notes to tables and figures are considered part of the table or figure and may be written as requirements. Annexes are designated normative (mandatory) or informative (non-mandatory) to define their application.

1.5
The values given in SI units are the units of record for the purposes of this Standard. The values given in parentheses are for information and comparison only.
2 Reference publications and definitions

2.1 This Standard refers to the following publications, and where such reference is made, it shall be to the edition listed below, including all amendments published thereto.

2.2 Definitions
The following definitions shall apply in this Standard:

**Area of review** - geographical area for a specific CO\textsubscript{2} capture and storage (CCS) project, on the land surface for onshore projects or on the sea surface for offshore projects, designated for assessment of the extent to which geological storage of CO\textsubscript{2} could adversely affect, through physical and chemical effects, life and human health, the environment, competitive development of other resources, and infrastructure. This is designated by the federal, provincial/territorial or state regulators, as applicable.

**Balanced cement plug** — the result of pumping cement through drill pipe, workstring, or tubing until the level of cement outside is equal to that inside the drill pipe, workstring, or tubing. The pipe is then pulled slowly from the cement slurry, leaving the plug in place. The technique is used in both open hole and cased hole applications when the wellbore fluids are in static equilibrium.

**Baseline** — a period of time during which information is collected prior to the injections of CO\textsubscript{2}.

**Biosphere** (in the context of CO\textsubscript{2} capture and storage) — the realm of living organisms in the atmosphere, on the ground, in the oceans and seas, in surface waters such as rivers and lakes, and in the subsurface at depths where water salinity is less than 10 000 mg/L. The biosphere also includes all water existing in the same realm.

**Carbon dioxide (CO\textsubscript{2}) stream** — a stream of carbon dioxide that has been captured from an emission source (e.g., a fossil fuel power plant) and meets applicable regulatory requirements for CO\textsubscript{2} storage. It may include any incidental associated substances derived from the source materials or the capture process and any substances added to the stream to enable or improve the injection process.

**Casing** — the pipe material placed inside a drilled hole to prevent the surrounding rock from collapsing into the hole.

**Casing shoe** — a reinforcing steel collar that is screwed onto the bottom joint of casing to prevent abrasion or distortion of the casing when it is forced past obstructions on the wall of the borehole.

**Cement** — material used to provide structural integrity and seal the well casing(s) to the rock formations exposed in the borehole. Cement also protects casings from corrosion and prevents movement of injectate up the borehole.

**Closure period** — the period in a project’s life cycle marked by the cessation of injection. This period can contain two sub-periods: a post-injection and closure period and a post-closure period.

**Collapse strength** — the pressure that will cause a mechanical well component to collapse.

**Containment** — prevention of leakage or migration of CO\textsubscript{2} and affected fluids from a storage complex.
Corrective actions — any actions taken to correct material irregularities or to contain breaches in order to prevent or stop the release of CO₂ from a storage complex. Corrective actions are implemented after an irregularity has occurred to help prevent or minimize damage.

Design, construction, and operation — the (a) design and construction of surface and subsurface facilities such as distribution pipeline and injection sites, injection wells, and monitoring wells and other monitoring facilities; (b) development and implementation of a monitoring measurement and verification program; and (c) operation of facilities over the active injection phase of a storage project.

Elements of concern — valued elements or objectives for which risk is evaluated and managed.

Elevated pressure zone — a zone within a storage unit where there is sufficient pressure to cause movement of formation fluids from the storage unit through a high permeable pathway into the biosphere or into an economic resource above the storage complex.

Event — a material occurrence or change in a particular set of circumstances.

Geological storage (geological sequestration) — the long-term isolation of CO₂ in subsurface geological formations. Injected CO₂ is trapped within the pore space, dissolved in formation fluids, and (over long periods) mineralized.

Geosphere — the solid earth below the ground surface and bottom of rivers and other bodies of water on land, and below the sea bottom offshore.

Hydraulic unit — a hydraulically connected geological unit (a) where pressure communication can be established on a human time-scale and measured by technical means; and (b) that is bounded by flow barriers (e.g., non-transmissive faults, salt domes, or beds and low-permeability geological formations) or by the wedging out or outcropping of the formation.

Leakage — any unintended movement (flow) of CO₂ and/or saline water (brine) across the primary seal(s) and out of a storage complex regardless of detectability or potential consequence. Depending on pathways and site characteristics, leaked CO₂ or brine can remain within intervening secondary traps in the overlying sedimentary succession, or can reach the biosphere and atmosphere.

Likelihood — a chance of something happening, expressed qualitatively or quantitatively and described using general terms or mathematically, e.g., by specifying a probability or frequency over a given period.

Long-term storage — storage of injected CO₂ streams in subsurface geological media for the minimum period necessary for CO₂ geological storage to be considered an effective and environmentally safe climate change mitigation option.

Primary carbon dioxide (CO₂) plume — the three-dimensional extent in a storage unit of the free-phase injected CO₂.

Mechanical integrity test (MIT) — a test performed on a well to confirm that it maintains internal and external mechanical integrity. MITs are a means of measuring the adequacy of the construction of an injection well and a way to detect problems within the well system.

Migration — the lateral movement of CO₂ and/or saline water (brine) within and outside a storage unit between the primary seals.

Packer — a mechanical device set immediately above the storage unit that seals the outside of the tubing to the inside of the long-string casing, isolating an annular space.

Permeable formation — a geological formation that allows or permits the movement of fluids within the formation on a human time-scale that can be observed through pumping and/or injection.
Post-closure period — the period after cessation of injection that is marked by a transfer of responsibility and liability from the operator to the designated authority. If responsibility and liability are not transferred, the project will not enter the post-closure period and will remain in the closure period until transfer occurs.

Post-injection period — the period after cessation of injection (including the closure period) that is marked by a transfer of responsibility and liability from the operator to the designated authority.

Primary seal — the low-permeability continuous geological unit (known in reservoir engineering as caprock and in hydrogeology as aquitard or aquiclude) that confines a storage unit immediately above or below it and that constitutes an effective barrier to the leakage of fluids from the storage unit.

Project life cycle — the stages of a project, beginning with those necessary to initiate the project (including site screening, assessment, engineering, and permitting) and leading up to the start of injection, followed by operations until the cessation of injection, and culminating in the closure period, which can include a post-injection closure period and a post-closure period, if a transfer of responsibility and liability occurs.

Project operator — the legal entity responsible for project organization, activities, and decision-making until a transfer of responsibility and liability to a designated authority (if such a transfer takes place).

Project stakeholder — an individual, group of individuals, company, or organization that believes its interests could be affected by a project and therefore wishes to take part in decisions about the project or to have its interests represented in discussions about such decisions. Stakeholders can include, e.g., employees, shareholders, community residents, suppliers, customers, non-governmental organizations, governments, regulators and other individuals or groups.

Protected groundwater — water that is defined as groundwater by legislation or a regulatory agency, is used for human consumption and/or agricultural and industrial purposes, and is protected against contamination through legislation or regulations.

Note: In Canada, protected groundwater is defined in each province or territory as water with a salinity less than a certain value (e.g., 4000 mg/L in Alberta). In the United States, the Environmental Protection Agency defines protected groundwater as groundwater with a salinity less than 10 000 mg/L.

Risk — the effect of uncertainty on project objectives (e.g., on performance metrics for an element of concern), expressed in terms of a combination of the severity of consequences (negative impacts) of an event and the associated likelihood of their occurrence.

Risk analysis — a process for understanding the nature and level of risk.

Risk assessment — the overall process of risk identification, risk analysis, and risk evaluation.

Risk control — measures whose purpose is to reduce risk.

Risk evaluation — the process of comparing the results of a risk analysis with risk evaluation criteria to determine whether (a) the risk, its magnitude, or both are acceptable or tolerable; or (b) treatment will be required to reduce the risk.

Risk evaluation criteria — terms of reference against which the significance of risk is evaluated.

Risk identification — the process of finding, recognizing, and describing risks.

Risk management plan — a scheme specifying the approach, management components, and resources to be applied to the management of risks.

Risk owner — a person or entity with the accountability and authority to manage risk.
Risk scenario — a combination of a threat-event scenario (a chain of circumstances through which a threat can cause an event to occur) and possible event-consequence scenarios (a chain of circumstances through which the consequences of an event can have a negative impact on elements of concern).

Risk treatment — a process to modify risk through implementation of risk controls.

Secondary carbon dioxide (CO₂) plume(s) — the three-dimensional extent of free-phase injected CO₂ developed in overlying aquifers as a result of CO₂ leakage.

Secondary seals — low-permeability geological units (known in reservoir engineering as caprocks and in hydrogeology as aquitards or aquicludes) in the sedimentary succession other than the primary seal. In the context of groundwater protection, these seals are located between the saline aquifer or hydrocarbon reservoir adjacent to a primary seal and the protected groundwater.

Secondary traps — saline aquifers and/or oil and gas reservoirs that are located in the sedimentary succession between a CO₂ storage complex and the base of protected groundwater aquifers, and that will trap CO₂ in case of leakage from the storage unit.

Significant risk — a risk whose magnitude is reduced through implementation of appropriate risk treatment to maintain compliance with this Standard.

Site characterization, assessment, and selection — a detailed evaluation of one or more candidate sites for CO₂ storage identified in the screening and selection phase of a CO₂ storage project to confirm and refine containment integrity, storage capacity, and injectivity estimates, and to provide basic data for initial predictive modelling of fluid flow, geochemical reactions, geomechanical effects, and risk assessment and monitoring measurement and verification program design.

Site closure — a point within a closure period when the operating site (e.g., injection facility) has met the specified requirements of the regulatory authority such that the post-closure stewardship and monitoring responsibility and liability can be transferred to the designated authority.

Site screening — the initial evaluation of the suitability of geologically storing CO₂ at the regional or subregional scale by identifying, assessing, and possibly comparing candidate storage formations or sites on the basis of criteria for containment, capacity, and injectivity.

Spatial data — data that are associated with a geographical location such as a point, a linear feature, or an area, including all attributes and information that can be tagged to the location (e.g., sample test results, surveys, classifications, photos, and reports).

Storage complex — a subsurface system comprising a storage unit and primary seal(s), extending laterally to natural boundaries or to the defined limits of the effects of a CO₂ storage operation or operations.

Storage project — a component of a CO₂ capture and storage operation that includes site selection and characterization, baseline data collection, permitting, design and construction of site facilities (site pipelines, compressors, etc.), well drilling, delivery of CO₂ to the storage site and CO₂ injection during the active injection phase, site closure (including well and facilities abandonment), and post-closure. It also includes testing and monitoring during all project phases.

Storage site — an area on the ground surface, defined by the operator and/or regulatory agency, where CO₂ injection facilities are developed and storage activities (including monitoring) take place.

Storage unit — a geological unit into which CO₂ is injected (e.g. depleted oil or gas reservoir or deep saline formation).
Surface cap — a permanent seal placed over the top of a casing (cut off below grade) to prohibit fluid migration into the well while also restricting access to the casing from the surface. A seal can be made using steel plate, cement, or some other means, singly or in combination.

Threat — an element that alone or in combination has the potential to cause damage or produce another negative impact.

Top management — a person or group of people who control a storage project at the highest level.

Transfer of responsibility — a transfer of all rights, responsibilities, and liabilities associated with a storage project to a designated authority which can include a host government.

Transport network — a network of pipelines, including associated compressor stations, for the transport of CO₂ streams from sources to storage sites.

Water column — a vertically continuous mass of water from the surface to the bottom sediments of a water body.

Well mechanical integrity (WMI) — the satisfactory mechanical condition of a well, such that engineered components maintain their original dimensions and functions, solid geological materials are kept out of the wellbore, and fluids including CO₂ are prevented from uncontrolled flow into, out of, along, or across the wellbore, cement sheath, casing, tubing, and/or packers.

3 Management systems

3.1 Scope of activities

3.1.1 General
Defining and implementing standards for geological storage is an essential component in the development of CO₂ capture and storage (CCS). Management systems are essential for the implementation and public credibility of geological storage processes. They need to be flexible to address changes during the project and they need to be robust to ensure that they meet site-specific project and regulatory needs. Management systems for a storage project interconnect through all project activities and phases.

The intent of management systems is to ensure that existing best practices are followed and to allow and promote improvement in the CCS field. Management systems also help to ensure that quality assurance/quality control, regulatory compliance, process improvements, and efficiency improvements are integrated into regular management processes and decision-making, as well as ensuring project transparency so that project stakeholders, regulatory authorities, and the public develop confidence in the management and implementation of storage projects. Another important function of management systems is embedding a risk-management process into the culture and practices of a storage project to help ensure that the events that can affect project objectives are identified and managed. Risk management shall include consideration of both internal and external factors.

3.1.2 Project operator’s roles and responsibilities
The scope of the project operator’s roles and responsibilities shall include operations that fall within the project boundaries as defined within Clause 3.2. These operational activities shall include those over which the project operator has control or significant influence, including those that have significant environmental or social impacts.

The project operator shall be responsible for
(a) all activities related to the storage project (including design, monitoring, and verification) and for the coordination and integration of those activities, especially activities that involve the handling and fate of CO₂,
(b) formulating a written statement of the storage project’s objectives, principles, and values and communicating this statement throughout the project organization and to project stakeholders and regulatory authorities

(c) coordinating, integrating, and communicating the activities and responsibilities of persons or organizations related to the storage project to project stakeholders and regulatory authorities

(d) coordinating the activities of other organizations acting on its behalf;

(e) ensuring that all persons and organizations employed by the project operator comply with the requirements of this Standard;

(f) defining clear boundaries with the capture and transport operators and establishing the activities, and responsibilities necessary to properly address interfaces among these systems;

(g) project risk identification, risk evaluation, and risk management during the life cycle of the storage project, and for coordinating activities to minimize risk; and

Note: Requirements for risk management are specified in Clause 5.

(g) determining and ensuring the availability and effectiveness of the energy, physical, financial, and human resources required to meet the objectives and principles of the storage project. The project operator can change over the project’s life cycle prior to a potential transfer of responsibility. In such cases, the former project operator shall be responsible for ensuring that all necessary documentation, materials, and processes are transferred to the subsequent project operator. The subsequent project operator shall be responsible for the smooth transition of management systems and processes. Records shall be retained by the subsequent project operator and should be retained by the former and subsequent project operators.

3.1.3 Continuous improvement

The project operator shall continuously improve the management systems by adapting to changing operational conditions, regulatory circumstances, or best practices. Continuous improvement shall be undertaken for all activities of the storage project, including planning, design, development, operation, monitoring, and closure. The project operator shall develop a continuous improvement process that identifies deficiencies and improvements, assesses alternatives, implements corrective actions, evaluates action effectiveness, and assesses the need for further action.

3.1.4 Project stakeholders

The project operator shall identify project stakeholders early in the storage project’s life cycle and engage them during all phases of the project. The project operator shall provide educational or informational resources relating to the storage project to project stakeholders, including employees.

Note: Examples of project stakeholders are included in the definitions.

3.1.5 Project definition

The project operator shall define a phased project scope that maintains and communicates the clear alignment of project activities with the storage project’s objectives and principles.

The project operator should organize, resource, and direct the activities of a storage project in accordance with the storage project periods specified in this Clause. A project operator may employ project periods different from that specified in this Clause, but should describe and document support for the alternative periods.

During all project periods, the project operator shall be responsible for obtaining and allocating resources for the work at hand, setting specific period objectives and schedules, and setting priorities in regard to competition for resources in terms of alternative sites or alternative uses of capital. Particular responsibilities apply to the project operator during specific project periods. The following list of project periods includes some of those requirements:

(a) Site screening period: the project operator shall set conceptual, geographical, geological, and hydrogeological criteria for, and boundaries of, the potential storage sites in consultation with stakeholders and in accordance with applicable laws and regulations (see Clause 4 and Clause 3.2 for details).

(b) Site selection and characterization period: the project operator shall:
(i) set performance assessment criteria by which the development of the storage project can be evaluated, and determine the relative importance of the attributes by which candidate storage site(s) may be compared;
(ii) ensure that the candidate site(s) have sufficient capacity to accept the anticipated final volume of CO₂, sufficient injectivity to accept the CO₂ stream at the desired supply rates, and containment characteristics that will ensure effective retention of the injected CO₂; and
(iii) establish the context and expectations for risk assessment and risk management, to ensure that the selected site(s) does not pose unacceptable risks to other resources, the environment, and human health, or to project developers, owners, and operators.

c) Design, development, and operation period: the project operator shall
   (i) develop and disseminate procedures for a QHSE (quality, health, safety, environment) protection program;
   (ii) develop and disseminate protocols that promote the effective integrated functioning of project operator and subcontractor organizations;
   (iii) select appropriate materials and methods for site development;
   (iv) apply best practices for site design, development, and operations, including wellsite design, drilling operation procedures, facility construction, monitoring hardware installation, and site security and emergency procedures; and
   (v) develop operations and maintenance procedures for monitoring and improving the performance of the complete integrated storage system over the project's lifecycle.

d) Post-injection period: the project operator shall
   (i) specify criteria for well abandonment and inspection; and
   (ii) specify criteria for continued monitoring that meets regulatory requirements and continues the progressive reduction of uncertainties regarding plume fate.

e) Closure period: the project operator shall
   (i) demonstrate that the storage complex has appropriate monitoring systems in place;
   (ii) establish archives and attendant systems to ensure the future public availability of project data and knowledge;
   (iii) prepare a plan for post-closure stewardship;
   (iv) decommission (or schedule for decommissioning) all surface equipment associated with the storage project that is not needed for the post-closure period;
   (v) plug and abandon wells within the storage site that are not considered necessary for future monitoring purposes; and
   (vi) ensure proper documentation of, and adherence to, transfer of responsibility requirements, where applicable.

f) Post-closure period: this Standard does not cover the post-closure period. See Figure 1.
3.2 Project boundaries

3.2.1 Responsibility
The project operator of a storage project bears responsibilities that can differ among the multiple overlapping dimensions potentially affected by the project. Within each dimension, the project boundaries can be defined in terms of legal descriptions (land surveys), contracts, permit conditions, surface and/or subsurface operational activities, or the physical effects (current or anticipated) of the project.

3.2.2 Organizational boundaries
The organization or person acting as the project operator for the storage project shall be identified and specific responsibilities and reporting relationships shall be defined between the project operator and every other person and organization involved with the project. If control of the project is shared among organizations, the project’s internal boundaries among organizations and areas of responsibility shall be defined.

3.2.3 Operational boundaries
The operational boundary of a storage project encompasses the activities that are directly controlled by the storage project. Activities within the project operational boundary include well drilling, storage project construction, site characterization, monitoring, personnel transportation, and the interfaces between CO₂ storage and transportation. For the purposes of planning and risk management, the project operational boundary shall be considered to include the communities within the area anticipated to be affected by the storage project and any monitoring facilities.

3.2.4 Physical boundaries
The project operator shall define the surface and subsurface physical boundaries of the storage project for approval by regulatory authorities.

   The surface physical boundary or boundaries shall include all project sites (injection sites, associated industrial facilities, and fixed, permanent monitoring facilities) that pertain directly to the storage project. The project operator shall be responsible for all of its activities within the permanent surface boundaries over the project’s life cycle prior to a potential transfer of responsibility, and should establish the legal right to limit access within the permanent surface boundaries.

   The subsurface physical boundary includes the storage complex and its overlying surface area wherein CO₂ injection could impose adverse environmental impact. Examples of important physical effects can include pore fluid displacement and impacts upon known subsurface resources or the exploitation thereof (e.g., impacts from fluid-pressure increase). The project operator shall estimate the nature and boundaries of subsurface effects and update and improve such estimates throughout the project’s life cycle prior to a potential transfer of responsibility as new data become available.

3.3 Management commitment to principles

3.3.1 General
Persons in top management and other management roles throughout the project operator’s organization shall demonstrate their commitment to best practices for the long-term safe geological storage of CO₂ by incorporating the principles specified in Clauses 3.3.2 to 3.3.4 into their actions and decisions.

3.3.2 Internal principles
The project operator shall
(a) operate on the basis of sound science and engineering;
(b) meet all legal and regulatory obligations and exceed them when appropriate;
(c) seek cost-effective means but allow a prudent margin for safety and environmental considerations;
(d) ensure safe CO₂ stream handling;
(e) implement an appropriate risk management system; and
(f) establish systems with the intent of ensuring that the site is monitored during the project’s life cycle prior to a potential transfer of responsibility so that unplanned occurrences can be addressed promptly (see Clause 7).

3.3.3 External principles
The project operator shall
(a) operate in an open and transparent fashion with project stakeholders and regulatory authorities to build public understanding, trust, and credibility;
(b) establish a local stakeholder advisory strategy and regularly engage with and seek input from local stakeholders;
(c) provide reports to the public when major milestones are reached or significant unplanned events occur; and
(d) seek independent assessments of significant project activities to ensure compliance with applicable standards and best practices.

3.3.4 Health, safety, and environmental principles
The project operator shall
(a) ensure that health, safety, and environmental protection for employees and local communities are the project’s highest priorities;
(b) ensure the integrity of all facilities which includes preventing leakage;
(c) develop and put in place an emergency response plan and team;
(d) prior to long-term (post-closure) stewardship ensure that environmental and human health impacts of the storage site and storage unit are acceptable;
(e) provide the appropriate resources to continually improve health, safety, and environmental protection.

3.4 Planning and decision making

3.4.1 General
The project operator shall establish, document, implement, and maintain a management system and shall continually improve its effectiveness.

Note: Examples of recognized management systems include ISO 9001 on quality management, ISO 14001 on environmental management, and ISO 31000 on risk management.

3.4.2 Intellectual property
Geological storage is an industry in which single projects are likely to involve multiple public and private organizations. While there is potential for both public and private benefit from the development of new technology, there is also potential for conflict and project failure because of disagreements over ownership of intellectual property (IP). Accordingly, the project operator should negotiate and establish early in the storage project’s life cycle inter-organizational agreements that address the ownership of present and potential IP.

3.5 Resources

3.5.1 General
The project operator shall evaluate and document at regular intervals the resource requirements under its responsibility.
3.5.2 Competence of personnel
The project operator shall determine the necessary competence of persons doing work under its control that affect health, safety, and the environment, and ensure that these persons are competent on the basis of appropriate education, training, skills, or experience. When appropriate, the project operator shall provide training or take other actions to achieve the necessary competence.

The project operator shall retain suitable documented information as evidence of competence.
All employees shall be trained on safe operating procedures relating to their job responsibilities and empowered with stop work authority related to safety issues.
At regular intervals, the project operator shall review required competencies to ensure that persons under its control remain up-to-date on changing regulations, knowledge, and best practices. The project operator shall ensure that subcontractors have equivalent programs and can demonstrate the competence of their personnel.

3.5.3 Equipment management
The project operator shall retain, manage, and direct sufficient equipment and infrastructure to facilitate all project phases. The project operator should document infrastructure and equipment allocations for the storage project. The project operator shall further consider establishing emergency provisions to prepare for loss of equipment or infrastructure failure to a point that adversely affects site development, operations, or closure activities.

3.6 Communications

3.6.1 General
The project operator shall develop a engagement plan early in the project, which shall include a trained designated liaison for media relations.
The project operator shall ensure that communication processes are clearly defined in plain language and that they are effective in advancing the storage project’s objectives.

3.6.2 Public communications
The project operator shall develop an open community outreach and engagement strategy. Input from the local community on the process and details of the strategy should be obtained. Local outreach and engagement should include public meetings, public notices, public updates, and site visits. A local newsletter and social media may be used.

The project operator should publicly communicate information on project activities, including: regulatory matters, standards performance, and safety and environmental issues early in the project’s life cycle, at regular intervals and when specific events occur.
Public communications shall be clear, transparent, and accurate, and include scientific, technical, and economic information concerning the storage project, and be expressed in language that the general public can understand. There should be a designated individual with a published telephone number and email address to answer questions.
Public communications dissemination shall include local community organizations and the local media. Employees can also be public stakeholders.
The primary focus for local communication should be issues related to the storage project and to matters of local benefit and concern with respect to environmental, economic, and social outcomes.
Public communications shall be respectful of all parties and respond to critics in a diplomatic and factual manner. The operator should engage the public in decision-making around aspects of the project, where possible so that it addresses their concerns and meets local needs.

3.6.3 Internal communications
Employees shall be fully informed of the nature and circumstances of the storage project, its goals and targets, and its progress in achieving those goals. All internal communications shall be clear, direct, and accurate.
Employees should be briefed on the regulatory expectations and requirements of government agencies and any guidance or operating procedures referenced by government regulations.

Employees should be informed of all stakeholder groups and their project concerns to lessen any public confrontations.

Internal communications shall be conveyed to project contractors and consultants where appropriate.

3.7 Documentation

3.7.1 General
Documentation systems shall be designed so as to meet the needs of the project operator and the regulatory authorities, from both an internal and external data collection and reporting perspective.

Institutional knowledge should be recorded to allow for the transfer of pertinent project information to either a subsequent project operator or to meet regulatory reporting requirements, as needed.

3.7.2 Information management
The storage project documentation shall include
(a) documented statements of policy and objectives;
(b) documented plans, procedures, and records required by this Standard, including the risk management plan, the monitoring plan, the engagement plan, and the post-injection and closure plan; and
(c) storage project artifacts and information products, including documents, records, and other data determined by the project operator to be necessary for the effective planning, operation, and control of its processes.

3.7.3 Knowledge and information management systems
The project operator shall implement and maintain over the project’s life cycle prior to a potential transfer of responsibility a centralized project information management system to organize, control, and archive project management artifacts, which may include, e.g., decision documentation, contracts, regulatory applications and approvals, financial records, engineering designs, meeting minutes, schedules, progress reports, communications, work plans and other artifacts.

The project operator shall implement and maintain over the storage project’s life cycle a centralized data management system to organize, control, and archive the diverse knowledge generated and acquired by the project, including scientific and spatial data sets, model results, maps, and other information products. The implementation of a geospatial system for knowledge and management should be considered.

4 Site screening, selection, and characterization

4.1 General

4.1.1
The purpose of site screening and selection is to identify prospective CO₂ storage sites, gather necessary information on the prospective sites, and use this information to select the most promising candidates for further characterization. Subsequent characterization and assessment of a site should demonstrate that the candidate site is likely to have sufficient capacity to accept the anticipated final volume of CO₂, sufficient injectivity to accept the CO₂ stream at the projected supply rates, and containment characteristics that will ensure effective retention of the injected CO₂ over the time-scales established by the regulatory authorities in the applicable jurisdiction. In addition, the characterization and assessment process shall demonstrate that storage of the CO₂ stream at the candidate site(s) does not pose unacceptable risks to other resources, to the environment and human health, and to project developers, owners, and operators.
The site screening, selection, and characterization process is inherently an iterative process, i.e., as more information is gained about the sites under study, sites that might have been thought to be suitable candidates will be eliminated from consideration and further study will need to be conducted on other prospective sites. Also, as a site is developed and operated, new data and information will be acquired or become available that will enhance the characterization and understanding of the site. Thus, while this Standard presents the screening, selection, and characterization process in a linear fashion, users of this Standard should anticipate applying its guidance iteratively.

4.1.2
The main mechanisms for CO₂ trapping in geological media are:
(a) structural and stratigraphic trapping, in which the upward and lateral movement of continuous free-phase mobile CO₂ (liquid, gas, or supercritical) in response to buoyancy and/or pressure forces within the storage unit (reservoir or aquifer) is prevented by low-permeability primary and secondary seals;
(b) residual-saturation trapping, in which discontinuous free-phase CO₂ is immobilized in individual pores by capillary forces;
(c) dissolution trapping, in which mobile and/or immobile CO₂ dissolves in aquifer formation water or reservoir oil; and
(d) mineral trapping, in which CO₂ dissolved in formation water reacts with the dissolved substances in the native pore fluid and with the minerals making up the rock matrix of the storage complex, with the result that CO₂ is incorporated into the reaction products as solid carbonate minerals.

Hydrodynamic trapping, or migration-assisted storage, is not a trapping mechanism by itself, but a combination of trapping mechanisms in laterally open deep saline aquifers where a combination of mechanisms contribute to CO₂ trapping.

4.2 Site screening
During the site screening process, sites that possess one or more of the following characteristics should not be considered for CO₂ storage:
(a) Technical:
   (i) lacking the necessary capacity and injectivity to match the rate of the CO₂ stream and the volume(s) to be stored;
   (ii) lacking, based on existing information, containment for the required period of time (as might be determined by the designated regulatory authority in the respective jurisdiction), including at least one regionally continuous primary seal sufficient to cover the storage unit;
   (iii) located in areas where containment is likely to be affected by seismicity and tectonic activity, although the presence of seismicity per se should not preclude a site from being considered;
   (iv) located in areas of extensive and high-density faulting and fracturing subject to reactivation;
   (v) located in over-pressured systems, i.e., systems where the natural pressure is significantly higher than hydrostatic, such that CO₂ injection would lead to quickly approaching fracturing pressure (vi) located in local-scale (short) hydrodynamic systems, i.e., systems with relatively short travel distances from recharge to discharge areas, such as systems in intramontane basins and thrust and fold belts;
   (vii) lacking adequate monitoring potential in regard to the evolution, fate, and effects of the injected CO₂ stream; and
   (viii) the mechanical integrity of legacy wells penetrating the storage complex cannot be confirmed or, if known, cannot be adequately remediated.
(b) Legal and regulatory:
   (i) located within the horizons of protected groundwater as defined in the respective jurisdiction;
   (ii) located at depths and locations where hydraulic communication with, and negative impacts on, protected groundwater can be demonstrated;
   (iii) located at depths and locations where hydraulic communication with, and negative impacts on, other natural resources (energy, geothermal, and mineral) can be demonstrated;
located in protected areas, e.g., national parks, and in environmentally sensitive areas as defined by regulatory authorities, that are likely to be negatively affected by operations; and

(v) located in areas where surface and/or pore space rights or operating permits cannot be obtained, e.g., military bases and native reservations, unless approved by the proper authorities.

Evaluation for site screening involves a certain level of site characterization, but this characterization could be based on readily available data and information, and may not require acquisition of new data and a significant evaluation effort. In some cases, sites deemed unsuitable on the basis of these criteria could be found suitable if additional data and information become available or alternative field development injection schemes are applied (e.g., horizontal wells or production of aquifer water), or legal and regulatory changes allow development.

4.3 Site selection
Site selection builds on the geological evaluation and land use considerations, building on the activities within Clause 4.2 during the initial site screening process. Data, information and knowledge acquired during the screening process should be incorporated into the site selection process. In areas where sufficient data (direct and/or analog) are available, models may be developed during site selection. These models can be useful for identifying data gaps and for quantifying uncertainty with respect to initial estimates. During the selection, the following should be assessed for sites that passed the screening stage:

(a) subsurface criteria:

(i) capacity — further refinement of site storage capacity as more information is gathered and the injection potential is better understood. This can be accomplished by evaluating existing well logs and cores to determine reservoir thickness, lateral variation, continuity, porosity, heterogeneity, and water saturation;

(ii) injectivity — influences the number of wells, well design (horizontal versus vertical), and injection pressure. Injectivity can be estimated from the well’s production history, core analyses, or hydraulic testing;

(iii) storage security, including the potential for leakage through;

(1) weak seals along faults and fractures, assessment of which may include
   (a) interpretation and reprocessing of legacy 2-D and 3-D seismic;
   (b) review of aeromagnetic surveys, logs (structure mapping), pressure mapping, and geochemical analyses of water;
   (c) identification of primary and secondary seals;
   (d) ensuring that the primary seal extends over the area of investigation/review; and
   (e) assessment of seismicity and tectonic activity;

(2) legacy wells, whose investigation should include the
   (a) number of wells penetrating the storage complex within the area of review;
   (b) age and construction of the wells;
   (c) well status (producing, suspended, or abandoned); and
   (d) history of well incidents and interventions in the area (i.e., surface casing vent flow (SCVF), sustained casing pressure (SCP), gas migration (GM), and well remedial operations);

(iv) pore space ownership rights (identifying pore space owners in the area of review);

(v) proximity to and potential effects on other subsurface activities, e.g., other CCS projects, disposal operations, enhanced oil recovery operations, mining, natural gas storage, and fracturing in or near primary or secondary seals (e.g., for shale oil or gas extractions);

(vi) proximity to and potential effects on valuable natural, energy, and mineral resources, e.g., producing hydrocarbon reservoirs, potable groundwater, geothermal energy, shale oil or gas, dissolved minerals (e.g., lithium), and sedimentary-basin minerals (e.g., Mississippi-type Pb-Zn deposits); and

(vii) handling and disposal of any brine produced by storage operations (if brine production is part of the CO\textsubscript{2} storage strategy for pressure control); and

(b) surface criteria:
(i) existence of and proximity to rights-of-way between (potential) CO$_2$ source(s) and the storage site;
(ii) existence of infrastructure, e.g., pipelines and rights-of-way, access roads, and power lines;
(iii) population distribution in the area overlying the storage site and along the projected path of the CO$_2$ plume;
(iv) land ownership in the area of review defined by the regulatory authority;
(v) proximity to other industrial facilities and to agricultural activities;
(vi) proximity and exposure to vehicular traffic, roads, railways, aircraft, or shipping traffic;
(vii) proximity to protected wildlife habitats (including endangered species) and environmentally sensitive areas (wildlife management areas, community watersheds, conservancy areas, ecological reserves, and protected areas);
(viii) proximity to rivers and other bodies of fresh water;
(ix) proximity to national parks and other reserved areas (e.g., military bases and native reservations);
(x) present and predicted development of adjacent properties;
(xi) site topography and variability in weather conditions;
(xii) cultural and historical resources; and
(xiii) socio-economic conditions.

Some site selection criteria are not necessarily related to storage capacity, injectivity, and security per se, but, nevertheless, should be considered because they affect siting. Proximity for safety and security of storage should be evaluated and defined in accordance with the regulations in the respective jurisdiction. Proximity for economic reasons does not form part of the considerations specified in this Clause, although proximity to (potential) source(s) of CO$_2$ to be stored and existence of adequate transportation networks — or planned transportation, if such networks are absent — is an important consideration.

By evaluating available surface- and subsurface-related information, site selection should result in a ranked list of selected potential sites for further characterization.

4.4 Site characterization and assessment

4.4.1 General
The characterization of a storage unit and of the primary seal shall consider all forms of CO$_2$ movement and trapping for free-phase (supercritical, liquid, and gaseous) and dissolved CO$_2$. Geological, hydrogeological, geochemical, geophysical, and geomechanical studies, and identification and characterization of legacy wells, shall be conducted. This may be achieved through the collection, interpretation, and, where needed and applicable, reinterpretation of all available data, including (a) seismic data; (b) well test data; (c) geophysical wireline data (cased and open hole); (d) wellhead injection pressure data; (e) aquifer or reservoir pressure data; (f) data from core samples; (g) analyses of sampled fluids (formation water, oil, and/or gas); and (h) oil and gas production and fluid injection data (water, steam, gas, and solvents).

Supplemental data may be obtained through 3-D seismic.

4.4.2 Geological and hydrogeological characterization of the storage unit
A geological and hydrogeological characterization of the storage unit to provide a reasonable estimate of capacity, injectivity, and containment shall be completed before injection for storage of any CO$_2$ stream. The characterization should include:
(a) assessment of the lateral and vertical stratigraphic relations and lithological properties of the storage unit to determine the extent of the storage unit and establish its boundaries. Available data from wellbores, geophysical data, facies analysis, and regional geological studies should be used for this purpose;
(b) identification and characterization of fault zones and structural features that could affect containment. 2-D and 3-D seismic and geophysics techniques should be used to identify any faults and structural anomalies. The locations of such features should be identified using wireline log analyses, core
analyses, and hydrogeological analyses described in Clause 4.4.2 (h) (e.g., comparison of flow regimes and formation water chemistries of the storage unit with porous and permeable units overlying the primary seal or underlying the storage unit), to ensure that these analyses provide insights on the transmissivity of these features;
(c) determination of the three-dimensional orientation (dip angle and direction) of the storage unit and its distance to subcrop or outcrop, if such is the case;
(d) mapping of the depth, top, and thickness of the storage unit using appropriate mapping tools and assessment of the degree of heterogeneity and compartmentalization that could limit capacity and injectivity;
(e) assessment of porosity distribution in the storage unit using wireline logs and core analysis data;
(f) evaluation of the initial pressure distribution in the storage unit (prior to human activities, if any) and of the current pressure distribution if the initial pressure is affected by production or injection of fluids (e.g., oil, gas, or disposal water);
(g) evaluation of injectivity, which is a measure of the rate at which \( \text{CO}_2 \) will be injected into the formation. This parameter could be determined by performing an in situ injectivity test with an appropriate fluid, conducting core flood tests using core samples from the storage unit, and/or by performing numerical simulations based on verified, locally relevant, data;
(h) evaluation of the background flow regime in the storage unit. Reservoir and hydrogeological studies should be conducted in order to effectively characterize water composition and the velocity and direction of the flow of formation water;
(i) evaluation of the potential total volume effectively available for \( \text{CO}_2 \) storage (using viable injection scenarios) on the basis of the porosity and thickness of the storage unit and of residual (irreducible) water saturation. This volume can then be converted into mass (tonnes) of stored \( \text{CO}_2 \) based on the relationship between in situ temperature, ultimate pressure distribution in the storage unit, and \( \text{CO}_2 \) density;
(j) development of a three-dimensional geological model of the storage complex, and all other relevant units in the sedimentary succession, using geological, well, and geophysical data;
(k) identification of the presence and size of known local traps, i.e., closures and pinch outs (which is a key parameter influencing the migration of injected \( \text{CO}_2 \));
(l) assessment of large-scale vertical and horizontal reservoir stratigraphic heterogeneity (well and seismic data should be used to image reservoir heterogeneity where appropriate, since this strongly influences \( \text{CO}_2 \) storage capacity and spread of the \( \text{CO}_2 \) plume);
(m) evaluation of permeability distribution in the storage unit, to be determined from core analyses, drillstem tests, and pressure build-up and fall-off tests;
(n) evaluation of the temperature distribution in the storage unit prior to injection of the \( \text{CO}_2 \) stream. The temperature of the storage unit shall be determined from wireline logs or direct measurement of the bottom-hole temperature using suitable instruments;
(o) estimation using preserved core samples of wettability, relative permeability and capillary pressure, as functions of saturation, for the water/\( \text{CO}_2 \) or water/oil/\( \text{CO}_2 \) system in the storage unit, including residual (irreducible) water and \( \text{CO}_2 \) saturations;
(p) evaluation of the flow regime and pressure distribution in the porous and permeable unit immediately overlying the primary seal above the storage unit; and

4.4.3 Characterization of confining strata

4.4.3.1 Primary seal
The sealing capacity of the primary seal shall be evaluated and qualified prior to injection of the \( \text{CO}_2 \) stream to provide adequate confidence in containment of the stored \( \text{CO}_2 \) stream. A detailed characterization of the primary seal shall be performed and should include;
(a) a determination of the stratigraphy, lithology, thickness, and lateral continuity of the primary seal. This should be based on data obtained from wireline logs, coring of the primary seal, or other suitable means;

(b) evaluation of primary seal integrity. The integrity of the primary seal should be assessed by evaluating the thermo-hydro-mechanical primary seal properties. The presence and extent of micro-fractures in the primary seal should also be considered in analyzing the integrity of the seal. Primary seal integrity may be tested where possible by conducting injection tests in the storage unit and measuring the pressure response in the aquifer immediately overlying the primary seal. The geochemical integrity of the primary seal should also be evaluated (see Clause 5.3.4);

(c) identification of fractures, faults, wells, and other potential leakage pathways through the primary seal that can require further monitoring during the operational stages of the project; and

(d) estimation of the capillary entry (displacement) pressure for CO\textsubscript{2} in the case of the primary seal being water saturated. This is the pressure at which CO\textsubscript{2} will overcome capillary forces in the primary seal and displace the water saturating it, thus opening a flow pathway. The displacement pressure should be measured in a laboratory on preserved core samples from the primary seal or by other suitable means.

### 4.4.3.2 Secondary barriers to CO\textsubscript{2} leakage

The presence of secondary barriers to CO\textsubscript{2} leakage shall be evaluated and include:

(a) identification of overlying saline aquifers and secondary seals that are present between the primary seal that confines the storage unit and the protected groundwater that can serve as a source of drinking water. The thickness and general properties of the overlying secondary seals should be determined based on data obtained from wireline logs and, if available, from cores taken from formations overlying the storage unit; and

(b) characterization of the aquifers within the storage complex and possibly in the overlying sedimentary succession in terms of the flow and chemistry of formation waters.

### 4.4.4 Baseline geochemical characterization

The chemical composition of the CO\textsubscript{2} stream proposed for injection and of the fluids in the storage unit shall be characterized, as well as the composition of the fluids and the mineralogy of the rocks in the storage unit and in the primary seal. The characterization shall include:

(a) CO\textsubscript{2} stream composition. Impurities can have an impact on geochemical trapping in the storage unit and on the integrity of the primary seal. Therefore, a compositional analysis of the CO\textsubscript{2} stream proposed to be injected shall be conducted. Gas chromatography is typically used to determine the composition of the CO\textsubscript{2} stream, whereas $\delta^{13}$C\textsubscript{CO\textsubscript{2}} determination can be useful in distinguishing injected versus native CO\textsubscript{2} during operations monitoring;

(b) the major and trace mineralogical components of the rocks in the storage unit and the primary seal. Analytical tools, including whole-rock analysis, optical microscopy, scanning electron microscopy (SEM), X-ray diffraction (XRD), electron microprobe analysis, particle size analysis, and BET (specific surface measurements) should be used on core and cutting samples;

(c) evaluation of the composition of and variability in the chemistry of the formation water and/or reservoir fluids, including dissolved gases, in the storage unit. The following considerations apply:

(i) fluids may be collected either down-hole or at the surface;

(ii) appropriate down-hole and surface fluid sampling and preservation techniques shall be used;

(iii) flow rates, oil–water and/or gas–water ratios, and non-conservative parameters (e.g., temperature, conductivity, pH, Eh, and alkalinity) shall be measured on site, whereas samples for other determinations (major ions, isotopes, etc.) should be preserved on site prior to being sent for laboratory analysis;

(iv) calculations shall be performed to assess fluid chemistry, as well as the relative masses of water, oil, and gas when they coexist, at formation P-T conditions; and

(v) the composition of samples of oil, gas, and/or brine shall be analyzed; and
(d) the chemistry of formation water (including their variability) and rock mineralogy in the first porous and permeable unit overlying the primary seal. This could be required for monitoring of CO₂ leakage through changes in water chemistry, as opposed to pressure.

(e) In certain cases, the operator may consider additional baseline sampling of the geosphere and biosphere based on the risk assessment conducted according to Clause 5.6.2.2(e).

4.4.5 Baseline geomechanical characterization

Geomechanical characterization of the storage unit and the primary seal shall be conducted based on well logs, in situ testing, or laboratory testing on preserved core material (where possible, other overlying units should be characterized). Geomechanical characterization shall include the following:

(a) evaluation of the natural seismicity and tectonic activity of the region where the prospective storage unit is to be located. In some cases, natural seismicity and tectonic activity can cause fracturing or fault reactivation, processes that can create or enhance permeable leakage flow paths. Accordingly, the available information related to seismicity and tectonic activities shall be collected and analyzed;

(b) characterization of the in situ stress regime (magnitude and orientation of principal stresses). Wireline logs (especially density, sonic, and oriented caliper and borehole imager logs), and small-scale hydraulic fracture tests (i.e., micro-fracture or mini-fracture tests) can provide this information and should be performed prior to injection of the CO₂ stream. In the case of mature oil fields, the reservoir pressure at the time these measurements are made should also be recorded, given that pressure change generally induces changes in stress magnitudes. Knowledge of the in situ stress regime in combination with the geomechanical modelling procedures described in Clause 4.5.5 should be used to assess the maximum CO₂ injection pressure limits rather than relying solely on estimates of the minimum in situ stress in the storage unit;

(c) determination of rock mechanical properties, which include (i) strength and deformation properties (e.g., Poisson’s ratio and Young’s modulus); (ii) thermal properties (e.g., thermal expansion coefficient, specific heat capacity, and thermal conductivity); and (iii) the attributes (e.g., orientation, spacing, roughness, aperture, infilling, and mineralization) of weak planes and discontinuities (e.g., bedding and natural fractures); and

(d) development of a mechanical earth model that includes an adequately detailed representation of the storage unit, primary seal and storage complex, and a simplified representation of the overlying sedimentary strata. The geometry of the mechanical earth model shall be based on the spatial distribution of strata as represented in the project’s geological model. Its constituent strata (referred to as mechanical stratigraphic units) shall be populated with the mechanical properties and in situ stresses obtained as explained above within Clause 4.4.5.

4.4.6 Well characterization

Wells have been identified as a potential pathway for upwards leakage. Therefore, a characterization of the existing wells that could be affected by the storage operation within the area of review shall be performed and include

(a) identification of the wells that penetrate the storage unit within the area of review;

(b) a determination of the status (producing, injecting, suspended, or abandoned) and ownership of the wells within the area of review;

(c) characterization of the population of existing wells by vintage, construction type, and type and extent of mechanical defects. For storage projects with numerous existing wells, this may be done on a statistical basis (i.e., a statistical analysis of all of the wells based on existing records to identify the more problematic wells, rather than statistical sampling of a limited number of wells);

(d) an evaluation, based on various criteria, of the potential of the wells to leak, and an identification of the wells that need observation and/or remediation, including those with well stimulation through fracturing and/or acidization.

Note: Evaluation criteria can include, e.g., the time and methods of drilling, completion, and abandonment; well direction; cement job records of any adverse conditions such as lost returns; records of top of cement measurements; cement evaluation log results; temperature and noise logging records; mechanical integrity tests (MITs); micro-
seismic or micro-deformation measurements; tubular metallurgy; and well abandonment records of cement plug depths.

(e) identification of wells within the area of review that penetrate higher horizons than the storage unit or adjacent structures, and their status and characteristics, for observation and possible remediation in cases where leaked CO₂ or displaced brine can reach them (e.g., aerial magnetometer surveys to locate old, unrecorded wellbores); and

(f) determination of the chemical composition of well materials that will come in contact with a CO₂-charged fluid.

Wells that have known significant mechanical defects (e.g., cement cracks and fractures, cement debonding, surface casing vent flow, aka sustained casing pressure, gas migration, casing failure, etc.) and are likely to be affected by the CO₂ plume or associated pressure in the near-mid-operational term shall be remediated in accordance with the regulations in the respective jurisdiction (see Clause 6.3.7). Remediation in other wells may be deferred until conditions warrant.

4.5 Modelling for characterization

4.5.1 General
The geological storage of CO₂ is a complex process that depends on in situ geological, hydrodynamic, geochemical, geothermal, and geomechanical conditions. Numerical modelling is a means of using these conditions to understand, predict, and communicate the fate and potential impacts of the injected CO₂ and associated pressure increase. Modelling is heavily influenced by the quantity and quality of the defining attributes of the system, including the associated data. The more limited the data set, the greater the uncertainty in predicted outcomes from the model. The level of uncertainty in model predictions is reduced by history matching of either laboratory experiments or field pilots. In addition, the flow, geochemical, and geomechanical models for CO₂ storage have not been tested as rigorously as conventional reservoir flow models applied in the oil industry or to groundwater, and therefore, more care shall be taken in interpreting the predictions of these models, particularly in light of the long containment period required for CO₂ storage. During the characterization phase of a storage project, when the data are of relative limited quantity, and of potentially variable quality, modelling of the storage site will be most effective in providing a sufficient technical basis and sensitivity analysis for risk management of the system (see Clause 5). Upon project approval, development, and subsequent commercial operation, these models can be further refined with new data to provide greater accuracy and confidence in the predicted outcomes.

4.5.2 Geological static model

4.5.2.1 General
A prerequisite for flow, geochemical, and geomechanical modelling is the creation of a geological static model that depicts the storage unit, primary seal, the storage complex and all other relevant units in the sedimentary succession, and their flow, mineralogical, chemical, and mechanical characteristics (see Clause 4.4). The conceptual model of the CO₂ storage complex shall be built to provide a framework that will be used to evaluate the potential behaviour of the storage complex. The conceptual model shall define the boundaries of the storage complex and contain sufficient detail to enable prediction and description of the performance of the system over time. The conceptual model will be refined as new data are acquired during Site Characterization (see Clause 4.4.1) to become a geological model suitable for numerical modeling.

4.5.2.2 Key modelling parameters
The geological static model shall describe the key geological, hydrogeological, geothermal, and geomechanical features of the storage complex, including
(a) areal extent;
(b) stratigraphy, lithology, and facies distribution;
(c) structure tops and isopachs;
(d) geological features (including, e.g., faults and fractures, subcrops, karst, and dip angle and direction);
(e) porosity distribution;
(f) permeability distribution;
(g) the composition of fluids and rocks in the storage unit and primary seal;
(h) the initial pressure regime and distribution;
(i) the initial temperature distribution and geothermal regime;
(j) the initial stress regime; and
(k) rock mechanical properties.

4.5.2.3 Modelling outcomes
The results of the geological static model should provide key parameters for
(a) flow unit definition for the flow model;
(b) geological definition for the geochemical model; and
(c) geological definition (mechanical earth model) for geomechanical modelling.

4.5.3 Flow modelling

4.5.3.1 General
CO$_2$ flow modelling shall be performed prior to commencement of injection of the CO$_2$ stream for the purpose of storage to predict the subsurface movement of stored CO$_2$ and assess storage capacity, injectivity, and risks arising from CO$_2$ injection activities. This modelling is intended to
(a) provide insight into quantitative predictions of the fate of CO$_2$ within the storage unit;
(b) evaluate the pressure buildup as a result of the storage operation;
(c) evaluate the upward movement and lateral spread (areal extent) of CO$_2$ (essential for designing effective monitoring programs) and of any impurity of interest (e.g., H$_2$S; SO$_x$; NO$_x$, etc.);
(d) evaluate the fate of the displaced formation water if the storage unit is a deep saline aquifer;
(e) evaluate whether preferential placement of injection or pressure-relief wells is effective in controlling pressure buildup and spread of the CO$_2$ plume; and
(f) examine potential leakage scenarios out of the storage unit and possibly out of the storage complex involving CO$_2$, contained impurities, and/or displaced formation water (brine) along fractures, faults, and/or wells (for risk assessment).

4.5.3.2 Key modelling parameters
Key modelling parameters should include the following:
(a) Within the storage unit: (i) initial pressure and temperature (ii) brine salinity (iii) equations of state for the fluids; (iv) porosity; (v) permeability; (vi) heterogeneity and anisotropy; (vii) formation geometry (thickness, and dip); (viii) relative permeability curves; (ix) capillary pressure curves; (x) fluid and rock compressibilities; (xi) the thermal properties of fluids and rocks (in the case of non-isothermal modelling); (xii) geomechanical properties (in the case of geomechanical modelling); and (xiii) mineralogy and reactivity data (in the case of geochemical modelling).
(b) Primary seal: permeability, capillary entry pressure, and other properties (e.g., as specified in Item (a)), depending on the level of modelling in the primary seal.
(c) Fluids: CO$_2$ stream composition and concentrations, physical properties, and phase behaviour.

4.5.3.3 Modelling outcomes
The results of modelling should provide information related to
(a) injectivity and injection scenarios (e.g., number and type of wells and well spacing);
(b) development of the CO$_2$ plume;
(c) movement and distribution of \( \text{CO}_2 \) in the storage unit;
(d) pressure buildup and areal extent;
(e) temperature distribution through the storage unit;
(f) movement of displaced fluids (liquids and gas), particularly formation water (brine) in deep saline aquifers;
(g) partitioning of \( \text{CO}_2 \) among supercritical, liquid, gaseous, and dissolved phases;
(h) dynamic storage capacity, i.e., the amount of \( \text{CO}_2 \) that can be stored under given scenarios of injectivity, regulatory constraints, and the number and type of wells (vertical and horizontal). The site-specific storage efficiency factor is an outcome of flow modelling and
(i) sensitivity analysis (indicating which parameters have the greatest influence on uncertainty);
(j) potential leakage paths out of the storage unit.

4.5.4 Geochemical modelling

4.5.4.1 General
An assessment of possible geochemical reactions among the injected \( \text{CO}_2 \) stream and the rocks and fluids of the storage unit and primary seal shall be performed to predict changes in baseline conditions and to predict their potential effect on injectivity, storage capacity, and storage integrity (security), and to inform the monitoring plan. This modelling is intended to
(a) assess the response of the storage unit to geochemical reactions, regarding trapping of \( \text{CO}_2 \) and porosity and permeability alteration;
(b) assess the response of the natural primary seal to geochemical reactions, including permeability alterations which may lead to potential flow of \( \text{CO}_2 \) or \( \text{CO}_2 \)-saturated brine through the primary seal;
(c) assess the response of the well to geochemical reactions, including cement and/or casing degradation, which may lead to potential flow of \( \text{CO}_2 \) or \( \text{CO}_2 \)-saturated brine; and
(d) assess (because pH conditions are key to selecting material for new wells) the predicted pH of the fluids in contact with the cement sheath for the life of the project in order to select suitable cements and tubular metallurgy for new wells to resist chemical degradation. The same assessment is needed to select remedial materials for existing wells (see Clause 6.3.7).
(e) In some cases, the operator may consider additional geochemical modeling of geochemical changes in the geosphere and/or biosphere overlying the storage complex based on the risk assessment conducted according to Clause 5.6.6.2(h).

These determinations can also have implications for rock alterations that might affect the geomechanical stability of the reservoir, seal, and wells.

4.5.4.2 Key modelling parameters

4.5.4.2.1
Key modelling parameters should include the following:
(a) storage unit: (i) porosity; and (ii) permeability.
(b) primary seal: (i) porosity; and (ii) permeability.
(c) solids: (i) mineralogy and relative amounts of each mineralogical-lithological unit; (ii) grain size; (iii) thermodynamic database; (iv) reaction rates, and (v) experimental data.
(d) fluids: (i) relative amounts of water, gas, and oil present; (ii) water composition; (iii) gas composition; (iv) oil composition; (v) pressures; (vi) temperatures; and (vii) thermodynamic database.

4.5.4.2.2
With regard to experimental data, the following data may be collected to populate geochemical models used to determine the effects of \( \text{CO}_2 \) reaction with minerals in the short term:
(a) data from laboratory investigation of short-term CO₂–water–mineral reactions in the storage unit and the primary seal;
(b) data from experiments on CO₂ flow/diffusion through a sample of the primary seal or the storage unit, which can be analyzed for mineralogical and permeability changes; and
(c) data from experiments on the chemical reactivity (including corrosion) of the well materials for CO₂ and formation fluids likely to be encountered.

4.5.4.3 Modelling outcomes

4.5.4.3.1 Modelling outcomes I: Chemical reactivity of the storage unit
Flow is assumed to be the dominant transport process in the storage unit. The results of the modelling should provide information related to
(a) the initial geochemical characteristics of the storage unit at in situ pressure and temperature;
(b) dehydration, dissolution, and precipitation reactions and fluid migration through rocks, particularly in the near-wellbore zone;
(c) the effect of long-term geochemical interactions with the CO₂ stream (preferably derived from 2-D and 3-D reactive-transport models); and
(d) changes in formation fluid composition and phase behaviour (e.g., interaction with dissolved and residual hydrocarbon species and release of toxic organics and heavy metals).

4.5.4.3.2 Modelling outcomes II: Chemical reactivity of the primary seal
Diffusion and flow are assumed to be the dominant transport processes in the primary seal, where diffusion dominates in the matrix and flow dominates along discontinuities (fractures) in the primary seal (either pre-existing or created by geomechanical failure during the injection of CO₂). To assess the extent of geochemical reactions between the injected CO₂ stream or a CO₂-charged formation fluid and the primary seal in the storage complex, the results of the modelling should demonstrate changes to original mineralogy of the primary seal and fluid and flow properties (i.e., porosity and permeability alteration as it affects the rock matrix and fractures/faults) over short- and long-term timeframes through exposure to free CO₂ (e.g., clay dehydration reactions) and dissolved CO₂ (e.g., mineral dissolution/precipitation) under diffusive and flow regimes.

4.5.4.3.3 Modelling outcomes III: Chemical reactivity of materials in existing wells
CO₂-saturated brine or water-saturated CO₂ will likely react with well materials (i.e., casings, cements, and bridge plugs), particularly if mechanical compromise allows fluids to migrate along the wellbore. For wells with minor mechanical defects, the following analyses and modelling should be performed to develop a life cycle monitoring and remediation plan:
(a) development of well defect models and application of reactive transport modelling (RTM) to predict well barrier performance;
(b) comparison of modelling results to similar conditions (e.g., CO₂-induced pH values) used in laboratory tests of material resistance (e.g., tubular metallurgy, cement composition, and elastomer type) to validate the predictions of the models; and
(c) individual characterization and modelling of wells found to be prone to minor defects (or which experience or modelling indicates that can develop significant defects) to determine the need for priority monitoring and remediation.

4.5.5 Geomechanical modelling

4.5.5.1 General
Geomechanical modelling of the storage unit, storage complex and of the entire overlying sedimentary succession (with emphasis on the primary seal) shall be performed in a risk assessment context to predict the potential effect of stress changes and deformations resulting from the planned CO₂ injection. This is intended to
(a) assess the integrity of the primary seal in the presence of pressure-induced stress changes. In the case of mature oil reservoirs undergoing conversion to storage, the modelling shall address changes experienced during the operational history of the reservoir (e.g., pressure depletion) as well as changes predicted for CO₂ injection;
(b) evaluate the potential for fault and/or fracture reactivation;
(c) assess the potential for induced seismicity;
(e) evaluate ground surface deformation (e.g., heave) as a result of injection;
(f) assess mechanical aspects of well integrity; and
(g) assess the integrity of the primary seal in the presence of temperature-induced stress changes (given that the injected CO₂ stream will most likely be at a lower temperature than the initial temperature of the storage unit).

The geomechanical modelling approach shall be a one-way coupled analysis in which the fluid pressure and temperature predicted from the flow modelling (see Clause 4.5.3) constitute the input into a geomechanical model at a suitable number of time steps to understand the evolution of stress and deformation within the model. The geomechanical modelling should be performed using 2-D and 3-D modelling tools. Although it is expected that one-way coupling will generally be adequate, it is possible that several iterations between the flow modelling and the geomechanical modelling will be necessary to ensure that the planned injection program will not affect injectivity or containment.

4.5.5.2 Key modelling parameters
Many parameters required for geomechanical modelling are obtained in the development of the mechanical earth model (see Clause 4.4.5) and the flow model (see Clause 4.5.3). The key geomechanical modelling parameters should include the following:
(a) geological model, which serves as the basis for establishing the mechanical stratigraphic units within the model and establishes the presence and orientation of existing faults and/or fractures;
(b) initial in situ stress regimes (directions and magnitudes) within the storage unit, primary seal, and overlying sedimentary succession;
(c) initial fluid pressure regime and distribution, which establishes the initial effective stress distribution required for geomechanical modelling;
(d) constitutive properties of the mechanical stratigraphic units in the model, which include rock strength and deformation properties and will establish how the rock behaves under CO₂ injection conditions; and
(e) depending on the outcome of the modelling specified in Clause 4.5.4.3.1, which models the chemical reactivity of the storage unit with the injected CO₂ stream, additional key geomechanical modelling parameters, which will include parameters that control how the strength and pore structure of the storage unit is changed geochemically.

4.5.5.3 Modelling outcomes
The results of modelling should provide information related to
(a) estimates of the maximum CO₂ injection pressure that will ensure no loss of integrity of the primary seal (e.g., CO₂ injection will not induce new tensile or shear fractures or reopen or reactivate existing discontinuities);
(b) evaluation of the potential for fault reactivation;
(c) evaluation of the effect of geomechanical processes on injectivity;
(d) evaluation of wellbore stability during drilling, which can affect well integrity and the near-well permeability of the primary seal;
(e) evaluation of deformation of the storage unit, primary seal and overlying sedimentary succession, including any effects deformations can have on surface facilities or the feasibility of pressure build-up monitoring based on ground deformation;
(f) evaluation of potential well integrity issues arising from geomechanical processes during injection and operation; and
(g) sensitivity analysis (indicating which geomechanical parameters have the greatest influence on uncertainty).
5 Risk management

5.1 General
A structured and systematic risk management process shall be implemented for each storage project. The risk management process should be an integral part of management, embedded in the culture and practices of and incorporated into the business processes of the project operator’s organization.

The responsibility for risk management shall reside with the project operator, but defined tasks may be delegated to and managed by other elements.

5.2 Objectives
The purpose of risk management is to ensure that the opportunities and risks involved in an activity are effectively managed and documented in an accurate, balanced, transparent, and traceable way. Effective risk management should
(a) help demonstrate achievement of objectives and improve performance relative to elements of concern;
(b) support strategic planning and development of robust project and change management processes;
(c) help decision makers make informed choices, prioritize actions, and distinguish among alternative courses of action;
(d) account for uncertainty, the nature of that uncertainty, and how it can be addressed; and
(e) recognize the capability, perceptions, and intentions of external and internal stakeholders that can hinder achievement of objectives.

Note: These objectives are consistent with the objectives described in ISO 31000.
5.3 Process

Figure 2
Schematic of risk management process for CO₂ geological storage projects

This Standard provides guidance on the steps of the generic risk management process shown in Figure 2 except the actual implementation of risk treatment, i.e., only risk treatment planning, follow-up, and review are addressed. The risk management process should be implemented during the initial site screening, selection and characterization period, and be iteratively repeated in a consistent, transparent, and traceable manner throughout the project life cycle.

Note: The risk management process described in this Standard is consistent with the risk management process described in ISO 31000.

5.4 Context

5.4.1 General
The project operator shall articulate the objectives of the project, define a conceptual model of the CO₂ storage system, and define the scope, conditions, and criteria for the risk management process. This shall include specifying the elements of concern and the risk evaluation criteria.

5.4.2 Elements of concern
Appropriate elements of concern shall be identified by the project operator for each project and include human health and safety, the environment, and system performance (e.g., injectivity, capacity, containment, and service reliability). The elements of concern should include cost, schedule, and reputation and may include industry stewardship, project financing, monitoring capacity, licensing and regulatory approval, research objectives, and public support.

5.4.3 System model
A conceptual geological static model of the CO₂ storage system shall be created to provide a framework that will be used to evaluate the potential behaviour of the storage system (see Clause 4.5.2). The system model shall define the boundaries of the storage system and contain enough detail to enable prediction and description of the performance of the system over time in a manner that provides a sufficient technical basis for risk management of the system. Prediction of model system performance shall be conducted in accordance with Clauses 4.5.3, 4.5.4 and 4.5.5.)
5.4.4 Identification of context

When the project objectives, conceptual model, elements of concern, and scope, conditions, and criteria for the risk management process are defined, the following elements should be considered:

(a) Natural environment:
   (i) atmosphere and meteorology;
   (ii) surface and marine environment (ecology, wildlife, plants, parks and reserves, etc.); and
   (iii) biosphere and geosphere (including geology, hydrogeology, geochemistry, tectonics, and seismicity).

(b) Regional natural resources:
   (i) groundwater;
   (ii) hydrocarbon resources;
   (iii) mineral resources;
   (iv) coal seams; and
   (v) geothermal energy extraction potential.

(c) Infrastructure and facilities:
   (i) surface:
      (1) buildings;
      (2) transportation corridors (roads, railroads, pipelines, etc.);
      (3) power distribution lines
      (4) oil and gas production and processing facilities; and
      (5) water reservoirs; and
   (ii) subsurface:
      (1) wells;
      (2) mines;
      (3) waste repositories;
      (4) gas storage sites; and
      (5) acid gas disposal sites.

(d) Human culture:
   (i) social context local to the project, including people and culture (demographic and historical factors that can influence how the project will affect, be viewed by, and be participated in by the local population);
   (ii) political (positioning and framing of the project by its proponents, stakeholders, and opponents with respect to current political elements and trends);
   (iii) economic (positioning and dependency of the project within the context of geographical and temporal economic factors, and the possible effects of the project on the local economy); and
   (iv) knowledge sharing and competence building (the progressive development, application, and propagation of knowledge and competence should be identified as a project objective in the early application phase of CCS processes and systems).

(e) Legal and regulatory environment and industry best practices:
   (i) relevant legislation, regulations, and directives and any plans by the regulatory authority to supplement or modify existing legislation, regulations, and directives;
   (ii) codes, standards, protocols, and guidelines that can guide risk management and facilitate demonstration of compliance with legislation, regulations, and directives; and
   (iii) manuals that document current industry practices and can guide cost-effective implementation of CO$_2$ storage technology in accordance with industry best practices.
(f) Project operator and subcontractors:
   (i) economic ownership of, contributions to, and liabilities for each component in the CCS system;
   (ii) specification of the project operator’s responsibility and the limits on its authority, including its risk management policies and guidelines;
   (iii) the experience of the organizations involved in the project with regard to managing risk through the development and implementation of a comprehensive risk management plan;
   (iv) delegation of responsibilities, functions, and relationships among organizations and individuals to ensure diligent and timely execution of project tasks; and
   (v) available resources, capacities, and capabilities for performing isolated project functions and for integration across all project components in the CCS system.

5.5 Risk management plan

Project operators shall develop and implement a risk management plan suited to their operation. The risk management plan should include a description of the following:

(a) organizational procedures and practices to be applied to risk management, including selection and availability of resources and assignment of responsibilities;
(b) a schedule for performing iterative risk assessments and activities supporting the risk assessments;
(c) principles and guidelines that will be applied to enhance the thoroughness, accuracy, transparency, and traceability of risk assessments;
(d) elements of concern;
(e) risk evaluation criteria for each element of concern tailored to the scope and objectives of the project (this can entail the use of qualitative or quantitative likelihood and consequence classes);
(f) thresholds for the tolerability and acceptance of risk related to each element of concern. Thresholds can be based on a combination of internal or external requirements or expectations, explicit policy statements, and regulatory requirements. Thresholds for tolerable risk can be determined by considering the practicality and cost-effectiveness of further risk treatment. If cost-effectiveness or impracticality of risk treatment is used as a basis for determining risk tolerability, project operators should identify and document the rationale applied to support the use of this basis, i.e., that risk can be deemed tolerable because further risk reduction is impractical (in terms of time, effort, likelihood of success, and secondary risk scenarios potentially entailed by the risk treatment) or not cost effective. The risk tolerance and acceptability thresholds shall be discussed with regulatory authorities and may be discussed with stakeholders;
(g) how the site-specific monitoring plan is designed to support iterative risk management activities (see Clause 7);
(h) how the site-specific modelling and simulation program incorporates new monitoring results and is designed to evaluate the effects of uncertainties and support the iterative risk analysis;
(i) how the risk assessment methodology considers and accounts for uncertainty that can influence the performance of the storage system;
(j) a project risk register that for each identified significant risk contains the following information:
   (i) a description of the risk scenario;
   (ii) a description of the planned or implemented risk treatment to mitigate the risk scenario;
   (iii) a description of the assessed effectiveness of each risk control in the risk treatment;
   (iv) the designated risk owner and the persons responsible for actions associated with execution of the risk controls in the risk treatment, and a schedule for timely execution of the controls; and
   (v) the estimated residual risk for each relevant element of concern following implementation of risk treatment and a description of the basis or rationale for the risk evaluation;
(k) a plan for iterative review of the risk register based on updated modelling and monitoring results;
(l) a schedule and process for monitoring and review of the overall risk management program to detect changes in the premises of the risk management plan, for tracking the effectiveness of implemented risk treatment, and for incorporating lessons learned to seek continuous improvement;

Note: Examples of changes in the premises of the risk management plan can include changes in regulations or in the financial, technological, economic, natural, and competitive environment. Circumstances or events that have occurred in other CCS projects can also alter the basis for risk evaluation criteria.

(m) a schedule and process for mapping and recording the risk management process; and
(n) a schedule and process for external communication and consultation with regard to risk management.

5.6 Risk assessment

5.6.1 General
Risk assessments shall include a comprehensive risk identification process, technically defensible risk analysis, and a transparent, traceable, and consistent risk evaluation process that aims to avoid bias. The results of the risk assessments shall set performance requirements for risk treatment and be used to inform the design of the monitoring and verification program (see Clause 7).

The level of rigour applied to risk assessment depends on the available information and the degree of knowledge about risk scenarios required to enable decisions for the relevant stage of the project. In general, the detail in the risk assessment will gradually be enhanced by each pass of the risk management process in Figure 2 until the identified risk scenarios are thoroughly assessed.

5.6.2 Risk identification

5.6.2.1 Principles
The project operator shall perform a comprehensive risk identification process that
(a) considers all features, events, and processes (FEPs) relevant to the identification of scenarios that can carry significant risk; and
(b) documents in a traceable and consistent manner which FEPs have been considered.

Note: FEP is not considered to be a standalone risk identification methodology, i.e., FEP databases should not be considered to provide a stand-alone check-list that a project operator can follow for risk identification. The intent of this Standard is to promote a thorough risk identification process for which FEP databases can be consulted as part of a quality control effort to ensure that the risk identification process has been comprehensive.

5.6.2.2 Process
The risk identification process shall include identifying threats to each of the following project criteria:
(a) the capacity to accept required CO₂ injection volumes;
(b) the injectivity to allow CO₂ injection at required rates;
(c) containment, i.e., prevention of migration of CO₂ or formation fluids out of the storage complex at rates or in a total mass sufficient to cause an adverse impact;
(d) geomechanical stability to ensure that CO₂ injection operations do not lead to seismicity, fracturing, or earth deformation sufficient to cause an adverse impact;
(e) adequate knowledge of the baseline (the current and future state of the natural surface and subsurface environment without influences from the storage project) to enable differentiation of geomechanical or geochemical changes attributable to the CO₂ injection operation from changes attributable to pre-injection background variation or to natural or other anthropogenic sources;
(f) technical and economic feasibility for effective modelling and monitoring to
   (i) allow timely implementation of appropriate risk treatment and provide confidence that the storage site is suitable for continued CO₂ injection operations; and
   (ii) ensure that metrics for site closure will be met;
(g) operational safety and environmental protection, i.e., avoidance of HSE impacts stemming from construction and operation of wells and the project surface infrastructure, and from project interactions with non-project human activities local to the project site and surrounding area;(i) identification and description of risk scenarios for each threat (which may include comparison of risk scenarios against an acknowledged database of FEPs);
(h) a description of the biosphere and economic resources in the geosphere that could be negatively affected by loss of containment or geomechanical effects of CO₂ injection operations; and
(i) identification of interdependencies among different risk scenarios, including the potential for cascading effects that could increase the likelihood or severity of consequences.
Tailored threat identification should be carried out for novel elements of the project, i.e., elements that are unique to the site under consideration, new to the organization, or have previously not been encountered in previous operations by the project operator.

5.6.3 Risk analysis

5.6.3.1 Principles
The risk analysis shall provide the technical basis for risk evaluation. The risk analysis shall be based on best available knowledge and scientific reasoning, and aim to determine the likelihood and severity of potential consequences for each risk scenario.

If significant uncertainty related to the likelihood and/or severity of potential consequences for a risk scenario exists, the degree of uncertainty should be modelled through sensitivity studies or scenario analyses and be used to provide reasonable uncertainty bands.

5.6.3.2 Process
The project operator shall document in a transparent, traceable, and consistent manner how each of the following elements has been considered in the risk analysis process:
(a) description of the risk scenarios;
(b) assessment of the likelihood of each risk scenario;
(c) assessment of the severity of potential consequences relative to the elements of concern for each risk scenario;
(d) identification and description of sources of uncertainty in the likelihood and severity of potential consequences for each risk scenario;
(e) identification of measures to reduce or manage uncertainties that can influence the risk evaluation and/or selection of risk treatment;
(f) identification of risk controls to prevent or mitigate identified risk scenarios;
(g) description of monitoring targets and detection thresholds required for timely implementation of appropriate risk treatment (identification and selection of appropriate tools that are sufficiently sensitive to detect indicators is part of the design and layout of the monitoring plan);
(h) data requirements and modelling and simulation studies to be performed to support the risk analysis (including data requirements and modelling and simulation studies to predict the effectiveness of risk treatment as well as the uncertainty associated with the effectiveness of risk controls);
(i) the aggregate likelihood that the respective events could be triggered by one of the identified threats; and
(j) the aggregate likelihood that a significant negative impact on each element of concern could follow from one of the respective events.

5.6.4 Risk evaluation

5.6.4.1 Principles
Risk evaluation is the process of evaluating the level of risk and the tolerability and acceptability of risk. For each significant risk, the result of the risk evaluation before mitigation sets the performance requirements for the corresponding risk treatment strategy. The selected risk treatment strategy should ensure that risk is reduced to and maintained at a tolerable or acceptable level.

The project operator shall identify and minimize sources of bias in the risk evaluation. When sufficient and demonstrably relevant data can be obtained, quantification of likelihood and consequences shall be based on appropriate scientific reasoning or auditable statistics and/or calculations. Otherwise, quantification shall be based on the documented judgment of experts who are qualified in terms of applicable professional expertise and project knowledge.

5.6.4.2 Process
The project operator shall document in a transparent, traceable, and consistent manner how each of the following elements has been considered in the risk evaluation process:
(a) level of risk before mitigation, i.e., without assuming any risk treatment;
(b) evaluation of the effect of risk treatment (this includes evaluating whether the risk treatment options for potentially tolerable risk are reasonably practicable, i.e., justifiable with reference to the principle that the risk should not outweigh the potential benefits of the activity);
(c) predicted level of risk after mitigation, i.e., contingent upon implementation of risk treatment; and
(d) degree of uncertainty attached to the level of risk, both before and after mitigation.

5.7 Planning and review of risk treatment
The project operator shall develop an appropriate risk treatment plan for each significant risk. The plan should describe the following:
(a) the target level of risk to be achieved through implementation of risk treatment;
(b) prioritization of preferred risk treatment options, including the priority order in which individual risk controls should be implemented. When the degree of uncertainty attached to the level of risk has an influence on the selection of a preferred risk treatment strategy, the project operator should explain how uncertainty is taken into account and defend why the selected strategy is robust with respect to the degree of uncertainty in likelihood and/or severity of consequences;
(c) further analysis to be performed or data to be acquired to seek continuous risk reduction and ensure that the risk remains acceptable or tolerable throughout the life cycle of the storage project;
(d) the effect of implemented risk treatment, which shall be considered as a cyclical process of assessing
   (i) the effect of the implemented risk treatment; and
   (ii) whether the residual level of risk is tolerable and, if it is not, generating or applying a new risk treatment and assessing its effectiveness; and
(e) a contingency risk treatment plan for managing conceivable but unexpected circumstances or incidents that carry significant risk.

5.8 Review and documentation

5.8.1 Review
The risk management plan and risk assessment results shall be reviewed and modified as necessary to ensure that risk is properly managed throughout the project’s life cycle.
To ensure that a fit-for-purpose risk management plan is implemented and adjusted as needed, the follow-up and review of the risk management process should comply with the following criteria:
(a) responsibilities for follow-up and review within the organization are clearly defined.
(b) the review of the risk management process ensure that;
   (i) the elements of concern are appropriate;
   (ii) risk controls are effective, efficient, and implemented as needed in a timely manner;
   (iii) information is gathered as needed to improve risk assessment and management;
   (iv) lessons learned are documented and analyzed;
   (v) changes in the context are detected, including changes to risk evaluation criteria and the risk itself (which can require revision of risk treatments and priorities); and
   (vi) emerging risk scenarios are identified in a timely manner.
(c) progress in implementing risk treatment plans is measured against defined performance targets.
(d) the results of the follow-up and review of the risk management process is recorded and externally and internally reported as appropriate, and is used as an input to the review of the risk management plan.

5.8.2 Documentation

5.8.2.1 Principles
The documentation of the risk assessment process shall be transparent and traceable.
5.8.2.2 Transparency
The risk evaluation criteria for each element of concern shall be documented. For all elements of concern other than those that strictly involve the project operator’s interests, the documentation shall specify the criteria by which risk is deemed acceptable or tolerable. For elements of concern that strictly involve the project operator’s interests, the documentation should specify such criteria.

Documentation shall include monitoring and modelling outputs, if these are used to form a basis for the risk assessments; shall cite the assumptions of and references supporting the modelling studies; and should describe the implications of monitoring thresholds and sensitivities for the risk assessment results.

5.8.2.3 Traceability
The results of risk assessments shall be recorded in a consistent manner so that risk assessments are comparable over time. The risk owners shall be documented. Changes in the assumptions and design of modelling and monitoring programs shall be documented and justified. If different risk assessment methodologies have been applied, how the results of updated assessments compare with the most recent assessment shall be demonstrated. If the results of an updated risk assessment deviate significantly from the prior assessment, the reasons for the differences shall be documented.

5.9 Risk communication and consultation

5.9.1 General
Communication and consultation regarding project opportunities and risk shall take place with both internal and external stakeholders.

5.9.2 Objectives
Risk communication and consultation shall be tailored to the knowledge level of CO₂ geological storage of those involved and should aim to accomplish the following objectives:
(a) to facilitate understanding of the nature of risk associated with CO₂ storage, the possible causes of risk, the potential consequences, and the measures being taken to manage risk;
(b) to provide to interested parties accurate and objective information about CCS in general and about the project in particular, including a balanced picture of opportunities and risk;
(c) to identify and record stakeholders’ perceptions of risk and their values, needs, assumptions, concepts, and concerns that could affect decisions based on risk considerations;
(d) to provide internal and external stakeholders with a common understanding of the basis on which decisions about risk tolerability and acceptability are made, and the reasons why particular actions are required to adequately manage opportunities and risk; and
(e) to address the thoroughness, accuracy, transparency, traceability, and consistency of the risk assessments, and the nature and degree of understanding of known or perceived risk scenarios.

5.9.3 Performance metrics
The communication and consultation program should aim to meet the following performance metrics:
(a) the context for risk management is appropriately established;
(b) the interests of stakeholders are understood and considered, and their needs met to the extent practicable within the scope and resources of the project;
(c) risk scenarios and risk perceptions are thoroughly identified and analyzed;
(d) stakeholder views are appropriately considered when defining the elements of concern, the risk evaluation criteria and in evaluating risk;
(e) regulatory authorities and relevant internal stakeholders agree that the risk management plan, including plans for change management, is sufficiently robust; and
(f) the internal and external communication and consultation plan is appropriate.
5.9.4 Scope of risk communication and consultation activities
The scope of risk communication and consultation activities will vary depending on the recipients and the underlying objectives. A communication and consultation program shall be developed to support the following three objectives:
(a) to facilitate open and effective dialogue with regulatory authorities during permit application and review. This should include consideration of
   (i) the process and rationale for site characterization and selection;
   (ii) the base of knowledge and understanding to support site and concept selection;
   (iii) the iterative risk assessment process;
   (iv) the monitoring and verification program;
   (v) the site and risk management performance;
   (vi) the plan for site closure and preparation for post-closure stewardship; and
   (vii) coordination of risk communication and consultation roles among operator and regulatory authorities;
(b) to facilitate open and effective communication and consultation with stakeholders and the public. This should include consideration of
   (i) the rationale for site selection (location of the storage site);
   (ii) plans for proactive and environmentally responsible risk management; and
   (iii) concerns and questions raised by stakeholders directly affected by the project; and
(c) to facilitate open and effective communication of responses to site performance that represents a deviation from expected or predicted site behaviour. This should include consideration of
   (i) plans to notify the authorities, stakeholders, and the public;
   (ii) plans to assess the scale and origin of the deviation;
   (iii) plans to identify and implement appropriate risk treatment;
   (iv) lessons learned and, if relevant, how the deviation could have been predicted and possibly avoided;
   (v) the deviation’s impact on the environment and/or economic resources, if any; and
   (vi) modifications to site-specific risk management plans, if required.

6 Well infrastructure development

6.1 Materials

6.1.1 General
Materials and equipment that will become a part of an underground storage system for geological storage of CO₂ shall be selected, constructed, and used in accordance with this Standard and shall be suitable for the conditions to which they will be subjected.

6.1.2 Material qualification categories
The following material qualification categories shall apply (see Clause 6.1.3):
(a) Complying materials: materials that comply with appropriate standards or specifications referenced in this Standard, including used materials serviced as necessary to meet the requirements of this standard.
(b) Unlisted materials: materials for which no standard or specification is referenced in this Standard.
(c) Used materials: materials previously employed in storage or similar facilities.
(d) Non-complying materials: materials that do not comply with appropriate standards or specifications referenced in this Standard.
6.1.3 Use of materials
Complying materials may be used without further qualification. Unlisted materials may be used if they are qualified for use by a demonstration they are safe for the conditions to which they will be subjected. Used materials may be reused if they are serviced to meet the requirements of this Standard. Non-complying materials shall not be used.

6.1.4 Material stress levels
Materials shall be designed to accommodate expected internal and external stresses during the life of the project. Internal stresses due to injection pressures shall be addressed by designing to the appropriate pressure ratings and margins of safety. Process upset conditions shall be considered to ensure that all CO₂ distribution lines, vessels, and other equipment within the storage facility can withstand maximum anticipated pressures or that adequate relief is provided.

External stresses on process CO₂ distribution lines shall be considered in the material design. Induced external stresses can be a function of thermal expansion and contraction, installation stresses, welding, and for CO₂ distribution lines, the terrain and topography. Road crossings should be designed so that no external stress from a vehicle is imparted to a CO₂ distribution line used for transport, i.e., exposed CO₂ distribution lines should not be considered acceptable for a road crossing and should be properly sleeved or buried to a depth that prevents their being stressed by the weight of vehicular traffic. Stream crossings should be designed to withstand external stress caused by high-water conditions, bank erosion, swift-moving water, and debris flows.

Note: The external stresses of downhole tubulars are addressed in Clauses 6.1.10.2 and 6.1.10.3.

6.1.5 Materials selection

6.1.5.1 General
Materials used for pipe, tubing, casing, pumps, electrical and safety equipment, instrumentation, and other components shall have properties that meet design conditions specified in this standard during construction and operation. When materials are selected, the following elements shall be considered:
(a) the type of fluid to be processed, transported, and stored;
(b) the range of operating pressures;
(c) the range of operating temperatures;
(d) the operating life of the project; and
(e) site-specific environmental conditions.

6.1.5.2 Material requirements related to CO₂
In general, dry CO₂ is not corrosive. CO₂ and free water combine to form carbonic acid, which is extremely corrosive in a carbon steel environment (carbonic acid is also referred to as wet CO₂). In dry CO₂ applications, carbon steel is an acceptable material from a corrosion perspective for process piping, process equipment, transmission and gathering pipelines, and wellbore tubular. Care shall be taken to ensure that proper industry-accepted practices are used for erosion allowances and pressure and temperature ratings. Wet CO₂ applications need corrosion-resistant materials and/or effective chemical treatment to maintain mechanical integrity.

Acceptable (wet CO₂) materials include
(a) carbon steel that has been plastic lined, plastic coated, fiberglass lined, or otherwise physically protected from the wet CO₂ stream. These materials shall be handled carefully to avoid creating defects or discontinuity in the protective coating;
(b) corrosion-resistant materials, e.g., certain grades of stainless steel and chrome that are sufficiently resistant to wet CO₂ corrosion. The user of a corrosion-resistant alloy (CRA) shall ensure that the chemical analysis of the material used meets the material analysis requirements specified in SAE-ASTM, Metals and Alloys in the Unified Numbering System.

Note: For further information on material requirements see NACE TM0177, API 5CT, API 5CRA, NACE MR0175, and ISO 15156.
(c) plastic, thermoplastic, and fibreglass tubulars that meet the pressure and temperature requirements of the application.

Carbon steel process equipment, process piping, and down-hole tubulars can be used in wet CO\textsubscript{2} environments if a chemical corrosion inhibition program is implemented and established by qualified personnel. The performance of these chemicals shall be monitored continuously to confirm their effectiveness. Laboratory tests shall be performed if there are any questions about the effectiveness of the inhibitor. Use of corrosion coupons is an acceptable method for monitoring the corrosion rate. Ultrasonic or other types of non-destructive testing can also be effective when used with a comprehensive corrosion-monitoring program.

**Note:** For further information see API Spec 15HR, API Spec 15LR, and API RP 15TL4.

### 6.1.5.3 Elastomer selection

Care shall be taken to select elastomers that are chemically stable in the presence of CO\textsubscript{2}. Selection criteria should include operating pressure and temperature conditions and impurities in the CO\textsubscript{2} stream. Elastomers that may be considered include, but are not limited to, the following:

- (a) packer elements;
- (b) wellhead O-rings and seals;
- (c) tubing connection O-rings; and
- (d) process equipment seals.

**Note:**

1. Elastomers should be constructed of
   - (a) urethane (URE-90 or equivalent);
   - (b) durometer peroxide-cured nitrile (Buna-N);
   - (c) durometer HNBR;
   - (d) fluorocarbons; or
   - (e) nylon.

2. For further information see API Bulletin 6J, API Spec 11D1, API Spec 6A, and ISO 14310.

### 6.1.6 Steel fittings, flanges, and valves

Steel fittings, flanges, and valves shall be designed to meet the requirements of the fluid to be processed or transported and resist adverse environmental conditions for the design life of the project. In general, fitting, flanges and valves shall meet or exceed the pressure and temperature requirements of the process system. As specified in Clause 6.1.5.2, care shall be taken in wet CO\textsubscript{2} environments to ensure that the material is corrosion resistant or coated to isolate the carbon steel from the wet CO\textsubscript{2}. Particular care shall be taken in the specification of elastomers in all fittings, flanges, and valves.

**Note:** Not all elastomers sealing elements are rated for CO\textsubscript{2} service.

Valve packing shall be Teflon® (TFE), reinforced Teflon® (RTFE), nylon or delrin based. Graphite packing or gasket material should not be used in wet CO\textsubscript{2} service. In addition, for relief valves and downstream flanges, if a large pressure drop is expected, the material shall be designed to accommodate very low temperatures.

**Note:** For further information see API Bulletin 6J, API Spec 11D1, API Spec 6A, API Spec 6D, ISO 14313, and ISO 14310.

### 6.1.7 Design temperatures

Process piping, fittings, valves, flanges, and other equipment shall be designed to accommodate both the expected range of process temperatures of the process fluid as well as ambient temperatures. Particular care should be taken with design temperatures where blowdown or large pressure drops can occur (because CO\textsubscript{2} can become very cold in these cases as a result of Joule-Thompson effects).

### 6.1.8 Electrical and instrumentation components

Electrical and instrumentation components shall be designed to accommodate the expected range of process and ambient variables. As is the case with piping, wet CO\textsubscript{2} is corrosive to such components:
Accordingly, such components should be selected to be compatible with the streams with which they may come into contact. Stainless steel should be selected for use in wet CO2 environments. Sealing elements for electrical and instrumentation components expected to contact wet CO2 should be made of elastomers that will withstand wet CO2 exposure (see Clause 6.1.5.2). Electrical hazardous area classifications should be reviewed to take CO2 into account. Unlike hydrocarbons, CO2 is a natural fire suppressant. Care should be taken in areas of confined space with potential CO2 release as CO2 will initially settle in low areas and then displace oxygen throughout a confined space. Note: Refer to Clause 6.2.1.1 for further safety requirements and considerations with respect to operations within confined spaces.

6.1.9 Piping
All pipe shall be designed to accommodate process fluids, pressures, temperatures, and environmental conditions. Pipe in this regard shall be considered to include, but not be limited to, process piping, vessels interconnect piping, flow lines, gathering lines, and trunk lines, along with the associated valves, flanges or couplings, regulators, and other equipment used in the piping system.

Piping in wet CO2 service shall be
(a) constructed of corrosion-resistant material, e.g., stainless steel, fibreglass, or plastic;
(b) lined with plastic, fibreglass, or another material to isolate the carbon steel from wet CO2 process fluids; or
(c) chemically protected by corrosion inhibitors.

Piping in dry CO2 service may be made of unlined carbon steel.

Note: For further information see API Spec 5L, API Spec 5LD, API Spec 6D, and ISO 14313.

6.1.10 Wellbore

6.1.10.1 Wellhead and christmas tree assembly
Wellhead and Christmas tree equipment shall be designed to accommodate the composition of the injected fluid, expected pressure and temperature ranges, and ambient conditions. The wetted areas of the wellhead, tubing hangar, and tree assemblies shall be designed to resist corrosion due to injected fluids. If wet CO2 is used, these portions of this equipment shall be made of corrosion-resistant material or clad with CRA material. Chemical corrosion inhibitors may be used. If chemical corrosion inhibitors are used they shall be in sufficient quantity to prevent corrosion. This shall be confirmed by regular inspection of the tree. Elastomeric seals shall be made of material that is compatible with the CO2 service (refer to Clause 6.1.5.2).

6.1.10.2 Casing
Casing should be designed as specified in Clause 6.3.4. Material selection should take into account the well-construction period as well as the producing/injection life. Conductor, surface, and intermediate casings should be designed to resist formation fluids (such casings are typically made of carbon steel). Long-string casing above the packer may be made of carbon steel if a chemically inert packer fluid is used. It is possible that the casing at the storage unit and below the packer will need to be made of a CRA material such as chrome or stainless steel to resist wet CO2 corrosion during the injection life of the well. Liners that could be exposed to injection fluids should be designed to the same material specifications as the long-string casing described in this clause.

Note: For further information see API RP 7G.

6.1.10.3 Tubing
Tubing should be designed to accommodate the injection conditions of the well, sized for the expected rates, and able to withstand the expected injection pressures. Material selection should be governed by the injection fluids expected in the well. Tubing in wet CO2 service shall be:
(a) constructed of a corrosion-resistant material, e.g., chrome alloy (chrome 13), stainless steel, fibreglass, or plastic;

**Note:** *Use of CRA tubular necessitates special handling techniques and tools.*

(b) lined with plastic, fibreglass, phenolic resins, or another material to isolate the carbon steel from wet CO₂ process fluids. To prevent damage to the lining, care should be used with lined tubing when running wireline or slickline; or

(c) chemically protected by corrosion inhibitors.

Tubing in dry CO₂ service may be made of carbon steel.

**Note:** *For further information see API RP 7G.*

6.1.10.4 Down-hole packers and tools

Down-hole packers and tools shall be designed to accommodate the expected fluids, pressures, and temperatures. For wet CO₂ service, packers should be fabricated of stainless steel or a chrome alloy that is resistant to wet CO₂. Packer elements should be designed in accordance with Clause 6.1.5.2. Down-hole tools such as nipples, mandrels, and mule shoes should be designed in accordance with the material criteria used for the tubing and packers.

**Note:** *For further information see API Spec 11D1 and ISO 14310.*

6.2 Design

6.2.1 Safety

6.2.1.1 General

If site enclosures are necessary, a safe entry procedure shall be established for entering wellhead enclosures and this procedure shall be followed by all persons entering the enclosures. CO₂, although non-toxic, has a specific gravity greater than that of air and can accumulate in low-lying areas. Personnel working in in-service CO₂ situations shall therefore be trained in safe working procedures for oxygen-deficient airspace. CO₂ saturation indicators should be used to ensure protection of site operators.

6.2.1.2 Identification signs

Permanent signs specifying the name of the well or storage facility, the name of the project operator, and a telephone number for emergency purposes shall be clearly visible.

6.2.1.3 Warning signs

In areas that can contain accumulations of hazardous or noxious vapors, the appropriate warning symbol shall be displayed on identification signs. Windsocks should be employed to indicate wind direction (i.e., for assistance in emergency evacuations). Such signage shall comply with local regulations.

6.2.1.4 Fire prevention and control

6.2.1.4.1 Permanent equipment spacing

Sources of ignition, flame-type equipment, and fires shall not be located within close proximity to a well or unprotected source of ignitable vapors. Equipment shall be spaced in accordance with or based on local regulatory requirements, as applicable.

6.2.1.4.2 Combustible material control

Wellsites shall be kept free of vegetation and combustible materials.

6.2.1.4.3 Wellhead enclosures

Where enclosures are used for wellhead equipment, the enclosures and wellhead equipment shall be designed and constructed to:
(a) exclude flame-type equipment;
(b) prevent the accumulation of hazardous gases within the enclosure; and
(c) use only electrical equipment approved for use within specified hazardous areas, as defined by local
regulations governing the location of the storage site.

6.2.2 Wellsite

6.2.2.1 Location

6.2.2.1.1 Setback considerations and proximity to population centers
A thorough evaluation of all surface and subsurface activities and their potential impact on the integrity of
the storage complex shall be conducted. This, evaluation, which shall include but not be limited to an
assessment of topographical and physical conditions, including proximity to other subsurface activities
and to population centers, shall be carried out in accordance with Clause 4.

6.2.2.1.2 Geological evaluation
A geological evaluation of the storage facility shall be conducted in accordance with Clause 4.5.4.2
and shall include numerical simulations for predicting plume size and migration.
Note: See Clause 4 for site screening criteria.

6.2.2.2 Layout, siting, and spacing
The distance between two adjacent wellheads and between wellheads and other surface facilities shall
ensure the unobstructed access to any well by drilling and service rigs and service vehicles that might be
needed during the drilling or service life of the well. Where adjacent wells are closer to each other than a
distance equal to the height of a drilling or service rig, the project operator shall ensure that physical
protection is provided for the adjacent wellhead not being used by a rig or vehicle (e.g., dropped object
protection, bump guards, and a cage).

Care shall be taken in the siting of all wells to:
(a) provide adequate access to the wells for inspection, maintenance, repair, renovation, treatment, and
testing; and
(b) avoid seasonal flooding.

Because of the density of CO₂, caution should be used when locating wells in low-lying areas.

6.2.2.3 Security

6.2.2.3.1 General
Project operators shall restrict unauthorized access to wells and storage facilities and should consider
employing security measures appropriate to the site location, e.g.,
(a) barricades;
(b) 2 m (6.56 feet) high small-mesh industrial-type steel fences;
(c) locking gates;
(d) site security personnel, as necessary;
(e) security lighting; and
(f) alarm systems.

6.2.2.3.2 Enclosures
Where fences or enclosures are used at wells, they shall be constructed in a manner that allows
unobstructed egress from anywhere within the confined area.
6.2.2.3.3 Identification signs
Signage shall clearly specify restricted access requirements, including warnings against trespassing to those without authorized access. Signage shall also comply with all local regulations.

6.2.3 Drilling

6.2.3.1 General
The depth of the storage unit, bottom-hole temperature, required diameter of the wellbore, lost circulation zones, the type of drilling fluid used, over- or under-pressured zones, swelling or sloughing shale, etc. should all be considered in the design of a drilling plan. The potential for fluid invasion and formation damage should also be considered when drilling through the targeted storage units. The above factors shall determine the type of drill rig and equipment needed to successfully complete the project.

Note: For further information on drilling practices to help ensure well control and integrity and zonal isolation, see API RP 65 Part 2, API RP 96, API RP 59, and API RP 53.

6.2.3.2 Wellsite considerations for drilling

6.2.3.2.1 General
The location and design of injection wells, vertical and horizontal deviated wells, and observation wells should be considered prior to the start of drilling activities. The wellsites should be large enough to accommodate the necessary drilling rig and equipment. Necessary provincial/territorial/state and local permits should be obtained prior to building the wellsites for drilling.

6.2.3.2.2 Injection wells
Injection wells are necessary for delivery of CO\textsubscript{2} to the subsurface geological storage facility. Information specific to the location and associated design of injection wells shall take into consideration the following:
(a) selection of a location with suitable well spacing design where the necessary volume of CO\textsubscript{2} can be injected without excessive subsurface pressure interference;
(b) adequate permeability and porosity for the anticipated volume of CO\textsubscript{2} required to be injected (so that injection pressures do not exceed the fracture gradient and fail the receiving formations); and
(c) positioning to take into account potential migratory paths from the targeted zone to other geological formations adjacent to the proposed injection formation.

Note: See Clause 4 for well siting requirements.

6.2.3.2.3 Vertical and horizontal/deviated wells
In some formations, the volumes of CO\textsubscript{2} required for injection operations can be more efficiently delivered by horizontal than vertical wells. Items that should be considered in drilling horizontal wells are:
(a) detailed geology, including the vertical depth of the target storage unit;
(b) azimuth of the horizontal well;
(c) length of the horizontal lateral;
(d) degree of curvature; and
(e) when to start the bend in formation.

6.2.3.2.4 Observation wells
Construction of monitoring and observation wells shall incorporate materials compatible with all fluids and conditions to be encountered during the life of the project. The location and design of observation wells shall take into consideration the following:
(a) locations that are suitable for monitoring reservoir pressure;
(b) potential migratory paths from the targeted zone to another formation;
(c) the lateral and vertical heterogeneity of the storage complex;
(d) fluid interface monitoring at the location of the spill point;
(e) permeability zones and stratigraphic traps above the storage zones; and
(f) low-permeability zones or formations adjacent to and in communication with the storage zone.

6.2.3.3 Surface casing setting depth

6.2.3.3.1 General
Well surface casing shall be set and cemented at sufficient depths to ensure:
(a) isolation of protected groundwater sources; and
(b) control of the well under maximum formation pressures and operating pressures prior to the next casing interval.

6.2.3.3.2 Safeguards for the preservation of protected groundwater
All site activities shall be performed in a manner that avoids endangering protected groundwater sources.

6.2.3.3.3 Pressure control for surface casing design
Surface pipe shall be set to a depth sufficient to ensure control of the well under maximum formation pressures and operating pressures prior to the next casing interval.

6.2.3.4 Casing design

6.2.3.4.1 General
Casing the well begins with the large-diameter conductor pipe driven or augured into the ground through the surface rubble or loam to hard pan, usually to a depth of 8 to 30 m (26 to 98 ft). The conductor pipe prevents caving and washout at the rig base and provides containment of the cement for the surface casing at ground level. Once in place, the conductor casing is grouted with cement to maintain integrity around the casing and prevent washouts.

The well is drilled out through the conductor to below protected groundwater sources and surface casing is run and cemented back to the surface to protect any groundwater sources encountered. The long-string or injection casing is then drilled out to total depth in the well and cased with the appropriate grade, weight, and size of casing to handle the operating parameters expected in the well and should be cemented back to the surface. At a minimum, the design of the casing should account for the internal yield strength of the pipe, casing collapse pressure, the pipe body yield, the required internal diameter of the pipe, and the corrosion resistance of the metallurgy.

The following design factors shall be considered:
(a) safeguards for the preservation of protected groundwater;
(b) well control requirements during drilling;
(c) wellbore conditions during the running and cementing of the casing;
(d) the range of operating pressures and temperatures for the well;
(e) composition of the CO₂ stream being injected into the reservoir;
(f) the projected life of the well;
(g) the integrity of the geological formations being penetrated and the fluid content of each formation;
(h) the depth of the well; and
(i) monitoring well design considerations.

Note: For further information see API RP 7G.

6.2.3.4.2 Service conditions for long-string casing design
The operating service conditions shall be considered during the design of long-string casing strings for injection and observation wellbores. Considerations in the long-string casing design should include the following:
(a) the H₂S concentration in the CO₂ stream;
(b) the moisture content of the CO₂ stream and/or the potential to add diverting agents such as water;
(c) the composition of inhibited fluid in the injection tubing and long-string casing annulus;
(d) the operating pressure at the storage unit;
(e) the differential pressure across the injection packer; and
(f) the operating range of temperatures anticipated, taking into consideration the lowest temperature expected due to \( \text{CO}_2 \) steam injection and the reservoir temperature.

The design influences of the service conditions shall influence decisions on the metallurgy of the casing, and on whether specialty alloys are required and at what part of the casing string special alloys are required (e.g., inconel alloy for the casing string over the storage unit and where the injection packer will be landed).

6.2.3.4.3 Yield strength
The following yield strength design requirements shall apply:
(a) surface casing connected into a wellhead and isolated from the long-string casing by seals shall have a yield strength design to support the maximum operating pressure of the storage facility or be otherwise protected by a pressure-relieving device or open vent;
(b) casing string other than surface casing shall be designed for a yield strength based on loads from the overburden gradient, formation pore pressures, and expected internal well pressures, and be designed in accordance with site geology;
(c) long-string casing design shall be based on the greater of the pressure gradient specified for the subsurface casing string and the maximum operating pressure gradient, with no allowance for externally applied pressure;
(d) casing yield strength shall be calculated in accordance with API Bulletin 5C2; and
(e) the casing collapse and burst pressure rating shall be sufficient to prevent well failure with expected pressures for well construction and operation. Safety factors specified in local regulations shall also be considered.

6.2.3.4.4 Collapse strength
The following collapse strength design requirements shall apply:
(a) casing set deeper than 450 m (1476 ft) shall be designed for collapse resistance based on a pressure gradient of 12 kPa/m (0.5305 psi/ft), with no allowance for internally applied pressure;
(b) long-string casing design shall be based on the greater of a pressure gradient of 12 kPa/m (0.5305 psi/ft) and the maximum operating pressure gradient, with no allowance for internally applied pressure;
(c) the casing collapse pressure shall be calculated in accordance with API Bulletin 5C2;
(d) casing shall not be subjected to a collapse pressure exceeding 90% of the minimum collapse resistance for the grade and weight of the casing being used; and
(e) collapse pressure reduction caused by axial loading shall be considered in the design.

**Note:** For assistance in developing collapse strength, see API RP 5C5/ISO 13679, API Spec 5CT/ISO 11960, and API TR 5C3/ISO 10400.

6.2.3.4.5 Tensile design
The following tensile design requirements shall apply:
(a) the casing minimum tensile strength shall be the lesser of the pipe body strength and the joint strength;
(b) casing shall not be subject to tensile loading exceeding 90% of the casing minimum yield strength for the grade and weight of the casing being used; and
(c) casing tensile design shall be developed in accordance with API Bulletin 5C2.

6.2.3.5 Liners
Liners shall be designed in accordance with Clause 6.1.3. The minimum overlap distance shall be subject to well design considerations for hanger placement in an area that has sufficient support from the cement above. Extended intervals for overlap can be necessary with unstable formations, e.g., a double-cemented annulus across salt zones in liner laps can be necessary to resist salt creep.
6.2.3.6 Number of casings
The cemented casings installed in a storage well shall include
(a) one casing set across all protected groundwater source zones; and
(b) one casing set across all porous zones located above the storage complex.

6.2.3.7 Abandonment
Clause 6.3.7 fibreglass tubulars shall apply to drilling abandonment procedures.

6.2.4 Completion

6.2.4.1 General
The completion of an injection well begins with a properly designed cement job in accordance with local regulations that places a well-bonded cement sheath around the injection casing from the casing shoe. This ensures that there is a safeguard for the preservation of protected groundwater aquifers by shielding the fresh water zones with casing and cement. The injection casing is perforated with the appropriate number and diameter of holes to establish sufficient communication with the storage unit of the reservoir to introduce the volumes required. Stimulation or injection enhancement treatments can be necessary; however, any injection enhancement treatment shall be performed in a manner that ensures the integrity of the primary seal. Tubing of the appropriate diameter and weight is then run with an injection-style packer to handle the fluid stream. Consideration should be given to the metallurgy of the tubing string and the use of internal coatings within the tubing to prevent corrosion and leakage of the injection string. Injection packers can be made of stainless steel or other corrosion-resistant alloys (see Clause 6.1.10.3).

6.2.4.2 Injection rates
The maximum injection rate required in the well shall determine the diameter of tubing needed to handle the volumes injected (and can influence the diameter of the casing necessary in the well). The maximum injection pressure shall determine the weight and grade of tubulars for the well. Packers of adequate internal diameter should be considered where subsequent wireline work might be desired during the life of the injection well.

6.2.4.3 Monitoring
The injection stream and the annulus between the tubing string and the casing shall be continually monitored at the wellhead for pressure. The injection stream and the annulus between the tubing string and the casing shall be continually monitored at the wellhead for pressure to ensure that pressure remains a specified amount below the formation fracturing pressure. At a minimum, monitoring of the temperature at the wellhead should also be considered.

Injection pressures shall be monitored, for the following reasons:
(a) injection pressure can be a leading indicator for subsurface issues, e.g., if injection pressure builds quickly after a period of no build-up, it is possible that there is a mechanical issue down hole that needs further investigation;
(b) injection pressure falling quickly can indicate a leaking or ruptured flow line. The project operator should consider installing a pressure safety low (PSL) switch that will activate a shutdown valve to prevent further leakage;
(c) if the injection pressure builds quickly to the point that an overpressure situation could occur, the project operator should consider installing a pressure safety high (PSH) switch that will isolate or shut down the pressure source and thus possibly prevent overpressure.

Injection temperature shall be monitored, as this datum is also useful for understanding the density of the injected fluids, which in turn allows bottom-hole injection pressures to be estimated. Pressure monitoring of the annulus is necessary to detect leaks within the tubing string, packer elements, or casing string. A metering device is necessary to monitor the volume of the fluid stream to be injected. Metering devices vary significantly in their operational requirements and can be as simple as an orifice meter or as sophisticated as a coriolis metering device. Onsite monitoring can be performed daily by an operator gathering information from a chart recorder or a remote terminal unit (RTU), or the data can be gathered...
by a supervisory control and data acquisition system (SCADA) and transmitted via radio, cell phone, or satellite system to a central computer database.

**Note:** See Clause 7 for monitoring requirements.

### 6.2.4.4 Service conditions

Excessive impurities within the flow stream can influence the outcome of a project on account of corrosion, improper measurement factors, and pump incompatibilities, and can be severe enough to cause reservoir damage. Monitoring for impurities shall be completed using industry standard techniques for sampling the flow stream.

Carbonic and carboxylic acid formed under certain conditions when CO₂ contacts water is the primary contributor to corrosion when CO₂ is handled. Some impurities found in produced CO₂ flow streams can also cause corrosion problems. Hydrogen sulfide (H₂S) is a potential impurity found with CO₂ and will react with water under certain conditions to form sulphuric acid. Corrosion problems in CO₂ injection wells may not exist under normal injection conditions. Only when the injection stream is contaminated with water or injection is stopped, allowing water to reenter the wellbore, will corrosion from CO₂ and its contaminants become a problem. Other forms of corrosion, e.g., electrolysis, can exist but are not related to CO₂ injection and can be corrected by cathodic protection or other means.

### 6.2.5 Recompletion of existing wells

#### 6.2.5.1 General

Recompletion designs for converting non-storage wells for use in storage operations shall ensure that the requirements of this Standard are met. Converting non-storage wells for use in storage projects should only be undertaken after careful evaluation.

#### 6.2.5.2 Casing

Recompletion of non-storage wells to storage wells shall be dependent on the construction details of the original well. The casing of the wells to be converted should use casing that meets the requirements of Clause 6.2.3.3.1. Allowance should be made for the age and condition of the casing so that no recompletion is performed in wells that cannot safely meet the requirements of Clause 6.2.3.3.1.

#### 6.2.5.3 Inspection and testing

Prior to conversion for storage operations, the long-string casing shall be inspected and tested for integrity over its full length by:

(a) obtaining and evaluating cement integrity logs;
(b) running and evaluating a casing inspection log for casing corrosion or damage;
(c) pressure testing the casing in accordance with field pressure testing techniques; and
(d) consideration of performing a baseline pulsed neutron log.

#### 6.2.5.4 Recompletion of existing storage wells

A well shall be recompleted if either of the following situations occurs:

(a) where hydraulic isolation is not indicated across the cement located above the storage complex where remedial cementing is needed to meet the cement design criteria for remedial cementing specified in Clause 6.3.4.5; or

(b) where a loss of mechanical integrity has occurred, as evidenced by (i) a failed pressure test; or (ii) communication between the tubing and the casing annulus, indicating a leak in the tubing or packer.

#### 6.2.5.5 Recompletion to reestablish mechanical integrity

##### 6.2.5.5.1 General

A well that has compromised mechanical integrity shall be worked over or recompleted to reestablish mechanical integrity. The loss of mechanical integrity should be investigated to determine whether the loss of integrity is from the tubing or packer or if the loss of mechanical integrity is from casing failure.
Pressure testing of the tubing and annulus will suggest where the problem lies. All recompletion work should have well control and wellbore security as the highest priority.

6.2.5.5.2 Repairing a tubing or packer leak
If the tubing or packer is suspected to have developed a leak, a plan shall be developed to repair the leak. If the well was constructed in such a way as to have a landing nipple above the packer, the tubing can be isolated and the pressure tested. If no blanking plug was used, a mechanical caliper log can be run to locate the leak. If a leak is discovered, the tubing shall be removed from the well and inspected and tested. If a seal-bore-type packer or tubing on/off tool was used, the tubing can be removed without removing the packer. Otherwise, the packer shall be removed with the tubing.

If the tubing fails a pressure test, the packer or seal assembly should be removed from the well and repaired or replaced. After such repairs or replacements have been completed and the components have been reinstalled into the well, the casing or tubing annulus shall be pressure tested to reestablish mechanical integrity. While the tubing is out of the well, a cement evaluation and casing inspection log should be run. All repair plans shall be reviewed and approved by the proper Regulatory Authority. If, after a thorough investigation, it is determined that the well cannot be repaired, it should be plugged and abandoned in accordance with Clause 6.3.7.

6.2.5.5.3 Repairing a casing leak
If the failed mechanical integrity test was due to a casing leak, a workover or recompletion plan shall be developed and executed to repair the damaged area. First, the type of leak should be identified by running a casing inspection log. Cement integrity should be investigated at this time by running a cement evaluation log. Other logs may be run to determine whether there is fluid movement outside the casing. After the results of these logs are evaluated, a repair shall be designed.

If flow is detected outside the casing, cement integrity shall be reestablished by squeeze cementing. If the problem is casing failure due to corrosion or a mechanical defect, several options exist to repair the casing leak. Squeeze cementing can be used to repair some leaks. Specially designed cement systems, e.g., ultra fine cement, very-low-fluid-loss slurries, and solids-free chemical sealant systems have proved effective in repairing casing leaks. Chemical sealants can penetrate pinhole leaks in casing to seal voids behind the casing and pore throats inside the permeability of formations. The use of a casing patch or lining the casing can be necessary to repair large leaks where there is also extensive structural damage in the casing or liner pipe.

Well integrity outside the casing should be established prior to using these methods. If there is fluid movement outside the casing, cement integrity shall be reestablished prior to the installation of a liner or casing patch. Wells involved in CO₂ storage operations shall be cemented back to surface such that casing replacement of long pipe sections might not be an economical option. In these cases, the available options can be limited to those that involve repairing the casing without pipe replacement, e.g., installing expandable liners and cement or chemical sealant squeezes. However, if casing replacement can be used, care shall be taken to ensure that the mechanical integrity of the well can be restored and maintained.

After the required casing repairs have been made the casing should be pressure tested. The packer and tubing will then be rerun into the well and mechanical integrity will be reestablished by pressure testing the tubing casing annulus.

6.2.5.6 Abandonment
Clause 6.3.7 shall apply to abandonment procedures.
6.2.5.7 Conversion records
Testing, evaluation, recompletion, and abandonment records for wells shall be prepared and retained in the project operator’s files.

6.3 Construction

6.3.1 General
Well construction planning and operations shall meet project goals and objectives while complying with applicable regulations such as those for CO$_2$ and other fluid containment. Published well construction standards cited by regulatory authorities and contractual documents shall also be implemented.

6.3.2 Safety plan
Safety preparedness (response plans) should be in place to mitigate spills caused by unexpected circumstances, e.g., drilling into high-pressure formations, which can cause kicks and the release of formations fluids to weak zones or to the surface.
Note: For further information see API RP 97.

6.3.3 Well site
Well sites shall be prepared to accommodate all drilling and service company equipment. Preparation shall include the drilling rig, mud system, pipe racks, tool sheds, offices, logging trucks, cement pump units, and materials delivery and storage areas. Well sites should also have enough room to allow placement of well-control equipment that is identified in any applicable emergency response plan.

6.3.4 Drilling

6.3.4.1 Inspection, transportation, storage, and handling of casings
Casings shall be inspected in accordance with API RP 5A5 and shall be transported, stored, and handled in accordance with API RP 5C1.

6.3.4.2 Casing threads
Before intermediate and long-string casing strings are run, all casing threads shall be
(a) inspected for gauge in accordance with API RP 5B1;
(b) covered by thread protector until the casing joint is hanging vertically in the derrick; and
(c) properly lubricated with a manufacturer-recommended lubricant or as specified in API RP 5A3/ISO 13678.

6.3.4.3 Running casing
Note: For further information see API RP 5A3/ISO 13678, API RP 5A5, API RP 5B1, API RP 5C1, and API RP 7G.

6.3.4.3.1 Casing torque
The following requirements shall apply to torque:
(a) for proprietary connections, the amount of torque applied to casing connections shall be within the specifications set by the casing manufacturer;
(b) applied casing torque shall be measured using a torque gauge; and
(c) when practicable, intermediate and long-string casings shall be run using power tongs.

6.3.4.3.2 Premium connections make-up
Threads that require a position make-up rather than a recommended torque shall be made up in accordance with the manufacturer’s recommendations. Torque/turn monitoring equipment shall be used during installation.
6.3.4.3.3 Threaded joints
Threaded joints shall be made up:
(a) in accordance with API RP 5A3/ISO 13678; and
(b) with thread compound that is compatible with the CO₂ being stored, except for the bottom two joints
(including the casing shoe), which shall be made up with thread-locking compound.

6.3.4.4 Casing cementing

6.3.4.4.1 Cementing design
Casing cementing design and operations shall provide, from the casing shoe to the planned top of
cement (TOC), a competent cement sheath in the annulus between the external casing surface and the
drilled hole’s formation surfaces that (a) structurally supports the casing; (b) resists all expected well and
formation loads; (c) completely seals the annulus to isolate pore pressures in covered zones; and (d) and
protects the casing from corrosive fluids in relevant zones. Cement should be selected appropriately in
order to be: non-shrinking when setting and ductile enough to sustain deformation due to change of
pressure and temperature over the operating envelope of the well. Also, when possible, the recipe should
offer additional chemical resistance to CO₂ degradation. Cementation should at least achieve hydraulic
isolation over all the primary seals of the storage reservoir.

6.3.4.4.2 Cementing operations
Casing cementing operations should comply with local regulations and take into consideration applicable
specifications and recommended practice Standards, including the following:
(a) API Spec10A/ISO10426-1;
(b) API RP10B-2/ISO10426-2;
(c) API RP10B-4/ISO10426-4;
(d) API RP10B-5/ISO10426-5;
(e) API Spec10D/ISO10427-1;
(f) API RP10D-2/ISO10427-2;
(g) API RP10F/ISO10427-3; and
(h) API RP65, Part2.

Furthermore as the CO₂ Sequestration industry evolves operators should apply latest technologies and
lessons learned from other Sequestration projects around the world.

6.3.4.5 Post-job cementing evaluation and remediation

6.3.4.5.1 General
After the cement has been placed in the annulus, the cement sheath should be evaluated using the
methods described in API RP65, Part 2, API RP 96, and applicable regulations. During the waiting on
cement (WOC) time, the hole should be kept full to maintain an overbalance across potential influx zones.
No other rig operations on the well shall be performed that will disturb the cement and damage the seal or
cause the cement to set improperly. Pressure testing of the casing should only be performed before
significant cement slurry gel strength has developed. After the required WOC time has elapsed, the
cement evaluation practices specified in API 10TR1 should be followed to determine whether the cement
has been properly placed in the annulus and the TOC is acceptable. Other methods to determine whether
the cemented annulus’s seal is suitable and has no leaks or defects may be performed, e.g., wireline logs
that detect flow behind the casing by measuring temperature, noise, and the flow of oxygen-activated
water and CO₂ molecules.

Defective cement sheaths shall be repaired using selected remedial methods and materials that meet the
structural support and sealing requirements of the primary cementing design. For example, when the
TOC is too low and a potential flow zone is exposed, a cement squeeze should be used to repair the
defect and seal the annulus from the actually measured TOC to the planned TOC. However, when
structural support is not an issue and only flow path sealing is needed, non-cement types of chemical sealing systems, e.g., solids-free, CO₂-resistant, chemical gel sealants, may be squeezed into flow paths such as a microannulus between the casing and the cement sheath to achieve deep penetration into those flow paths in the cemented annulus.

**Note:** More information is available in API Technical Report, “Summary of Carbon Dioxide Enhanced Oil Recovery (CO₂EOR) Injection Well Technology”.

### 6.3.4.5.2 Pressure testing in mills

Casing that has not been pressure tested in the mill for strength in accordance with API Specification 5CT/ISO 11960 shall not be installed in storage wells.

### 6.3.4.5.3 Field pressure testing

Long-string casing shall be pressure tested for leaks and strength by

(a) isolating the casing from the formation; and
(b) testing to a pressure that is 1.1 times the maximum operating pressure measured at the wellhead, but not greater than 100% of the casing minimum yield pressure at any point along the casing, and continuing the test for the period of time required to reach stabilization.

All casing shoe pressure testing should be performed to contain drilling pressures expected for the next hole section plus a safety factor (kick tolerance) in accordance with the LOT procedure described in Section 5 of API RP 65, Part 2.

### 6.3.4.6 Core acquisition

#### 6.3.4.6.1 General

Conventional or sidewall core shall be collected to sufficiently document the storage complex prior to developing or commissioning the storage facility.

**Note:** See Clause 5.2.3 for further requirements on geological and hydrogeological characterization of the storage unit.

#### 6.3.4.6.2 Core handling

If the collection of core is required each core taken shall be:

(a) extracted from the core barrel in a manner that preserves its condition;
(b) placed in a core container strong enough to prevent breakage of the core;
(c) accurately and durably labeled with the
   (i) name of the well;
   (ii) depth interval from which the core was obtained; and
   (iii) sequential number of the container; and
(d) where caprock core is taken, preserved in a manner that minimizes evaporation and preserves the fluid saturations of the core before shipment to the laboratory.

#### 6.3.4.6.3 Core analysis during development operation and construction

Additional core collection and/or analysis of existing cores or additional sidewall core from caprocks and target reservoirs should be undertaken, as needed, for site development and operations to ensure proper construction and operation of injection and monitoring wells. The results of the analysis, if different from previous site characterization analysis, should be considered in injection and well design and operations.

### 6.3.5 Completions

#### 6.3.5.1 General

All wells involved in CO₂ storage projects, whether injectors or monitoring wells, shall be completed in a manner that meets project goals while maintaining wellbore integrity. A detailed completion plan shall be
developed and subjected to stakeholder and peer review to ensure that project goals are met. All materials used shall meet the requirements of Clause 6.1.5.

6.3.5.2 Workover procedures
Workover procedures used during the completion process shall employ best industry practices while maintaining a focus on safety and wellbore security.

6.3.5.3 Wireline and logging procedures
Wireline logging procedures shall be used to determine casing and cement integrity, correlate formation depths, and establish baseline conditions for monitoring and verification activities. The logs used may include, (a) casing inspection log; (b) cement evaluation log; (c) cement bond log; (d) density, dipole (shear) sonic log, FMI, and ultrasonic imaging logs; (e) temperature log; (f) noise log; (g) pulsed neutron, gamma ray, spontaneous potential, and collar locator log; and (h) any other log that has been designed and approved for the purpose for which it is proposed to be used.

Various wireline, slickline, and logging jobs may be used as necessary throughout the operating life of a storage well, including wireline logs to determine casing and cement integrity, correlate formation depths, and establish baseline conditions for monitoring and verification activities.

6.3.5.4 Wellbore integrity
Wellbore integrity shall be established using logs and pressure testing. The casing shall be pressure tested prior to starting completion. Once the injection or monitoring packer is installed, the tubing and casing annulus shall be pressure tested to ensure mechanical integrity. All pressure tests shall be performed to applicable standards and in a manner that does not cause casing and cement debonding.

6.3.5.5 Formation testing
Formation tests may be performed to establish reservoir properties, e.g., injectivity testing, pump testing, initial reservoir pressure testing, and pressure transient testing, separately or in combination. These tests shall be reviewed to ensure that the formation has the required injectivity and to confirm reservoir models that will be used to predict CO₂ movement in the reservoir. Accurate records shall be kept of all completion activities and retained throughout the life of the project. If required, copies of all completion records shall be transferred to the regulatory authority issuing the well permit and to any other regulatory authority as required.

6.3.6 Workover procedures

6.3.6.1 General
During the life of the project it is possible that a workover will be required to repair a defective component or to obtain information concerning wellbore integrity. After injection into the receiving reservoirs has occurred, all workovers shall be conducted using best industry practices for maintaining wellsite safety and wellbore security. Well control shall be of primary concern to ensure that no injected CO₂ can escape from the formation and back into the atmosphere. A detailed workover plan shall be established prior to starting any workover operation and subjected to stakeholder and peer review. Necessary permits and approvals from all Regulatory Authorities involved shall be obtained prior to starting workover operations (e.g., sundry notices).

6.3.6.2 Wireline logging procedures
Wireline logging may be used during a workover for monitoring or in recompletion activities. All wireline operations during workovers should be performed in accordance with best industry practices for pressure control. The composition of wellbore fluids shall be considered in designing wireline operations by both the operators and service providers to prevent damage to wireline cable and tools.
6.3.6.3 Wellbore integrity
During workover activities, wellbore integrity should be reestablished as in the original completion. Wellbore integrity can be verified using a combination of wireline logging and pressure-testing methods.

6.3.6.4 Workover records
Accurate and detailed records shall be kept of all workover operation activities. An accurate record shall be kept of any changes made to, or recompletion of, any well (either monitor or injector) involved in the project. These records shall be retained for the life of the project. If required, copies of all workover records shall be transferred to the Regulatory Authority issuing the well permit and to any other Authority as is required.

6.3.7 Abandonment and restoration

6.3.7.1 General
Well abandonment design shall ensure the protection and isolation of potential CO₂ storage units, prevent leakage, and ensure that the surface is returned to near-original condition. This activity shall be guided by the Regulatory Authority issuing the well permit.

Clauses 6.3.7.2. to 6.3.7.5 specify requirements pertaining to abandonment of wells during the various project activities.

Note: For further information see API Bulletin E3.

6.3.7.2 Discovery of an abandoned well
All abandoned wells shall be identified and applicable records searched to determine how the well was plugged and whether the method of plugging met the requirements of Clause 6.3.7. If the well cannot be identified, no records on how the well was plugged can be found, or the well was plugged in a manner that did not meet the requirements of Clause 6.3.7, the well shall be monitored for leakage and repaired if necessary.

6.3.7.3 Abandonment of a well during construction
If, during the construction of a well, a condition occurs that requires the well to be abandoned, it should be plugged at the direction of the regulatory authority that issued the well permit, and in a manner that ensures that all of the requirements of Clause 6.3.7 are met. Such conditions might include, but are not limited to, loss of drilling tools in the well, a stuck pipe that cannot be recovered, loss of coring or logging tools in the well, or conditions in the hole that make continuation of well construction operations unacceptable. The loss of a radioactive logging tool requires special provisions beyond those specified in Clause 6.3.7. All wells plugged as a result of a lost radioactive tool shall be plugged in such a manner that Clause 6.3.7 is met as well as special provisions required to plug a well where a radioactive tool is lost. The preferred method of plugging shall be the balanced plug method. Care shall be taken to ensure the integrity of each plug, before the next plug is installed.

Note: For further information, see API Bulletin E3.

6.3.7.4 Well is found to be unsuitable after completion but before CO₂ injection has occurred
If, after completion, a well is found to be unsuitable for injection or monitoring, it should be plugged to meet the requirements of Clause 6.3.7. Casing and cement integrity shall be established, and if remedial work is required, the well shall be remediated so that casing and cement integrity are established. All open perforations should be sealed off using the cement squeezing technique as well as by permanent bridge plugs and cement plugs above the perforations. The well should then be further plugged at the direction of the Regulatory Authority issuing the permit and in accordance with a method that meets the requirements of Clause 6.3.7.
6.3.7.5 End of the project
At the end of the life of the project, all wells associated with the project shall be plugged in a manner that meets the requirements of Clause 6.3.7. During plugging, care shall be taken to maintain well control at all times so that no injected fluids are released into the wellbore or the atmosphere. All CO₂ shall be flushed from the wellbore and the wellbore should be filled with a fluid of a density that will maintain well control. Casing and cement integrity logs should be rerun and compared to the original baseline logs to confirm cement and wellbore integrity. If either the cement or the casing is found to be deficient, repairs shall be made so that the wells can be successfully plugged to meet the requirements of Clause 6.3.7. All open perforations should be sealed using the squeeze cementing technique and then plugged by a series of cement plugs, permanent bridge plugs, or both, or by completely filling the well with cement. The Regulatory Authority issuing the well permit should be consulted with respect to plugging requirements.

6.4 Corrosion control

6.4.1 General
Mechanical integrity shall be maintained during the operation of a storage project as a primary means of mitigating mechanical integrity problems related to the effective design of materials, coatings, and chemical programs to prevent internal and external corrosion of steel components. Once designed and in place, ongoing operations should include a program to monitor the effectiveness of the corrosion mitigation efforts. The program can include, but is not limited to, the following:
(a) chemical analysis of injected fluids for indications of trace metals;
(b) corrosion coupons placed in the injection stream; and
(c) ultrasonic or other non-destructive testing of vessels and pipe for wall thickness (metal) loss.
Ongoing maintenance should include external coatings and periodic visual inspection of the interior portion of all vessels for corrosion.

6.4.2 Design considerations
Design shall include a careful analysis of the expected injection fluid composition throughout the injection. Pure, dry CO₂ is benign from a corrosion perspective, but water and other impurities such as H₂S need to be considered. The design should also consider external environmental conditions. External corrosion can be influenced by the weather, ability of pipe to maintain external coatings, and whether the steel is exposed to the air (e.g., buried pipe versus pipe in a pipe rack). Location, offshore piping, and structural steel is specified to accommodate salt laden air. Onshore piping may or may not have this environmental consideration.

6.4.3 Cathodic protection systems
Piping and vessels should be adequately protected against galvanic corrosion by using cathodic protection. Vessels and skids should be adequately grounded. An impressed-current cathodic protection system should be considered for flow lines, pipelines, gathering lines, trunk lines, and (possibly) well casing in areas subject to highly corrosive conditions.

6.5 Operation and maintenance

6.5.1 General
An operation and maintenance plan should be developed and implemented. The plan should provide for regular inspections to prevent a device or well component related to surface equipment from failing and to ensure that degradation normally experienced during the operation of equipment is repaired as necessary to maintain mechanical integrity.
6.5.2 Operation constraints and limitations

The geological, structural, and integrity characteristics of the proposed storage region shall be evaluated to establish constraints and limitations, e.g., minimum and maximum operating conditions and pressures. This evaluation shall include:

(a) reviewing available pressure and production history data and test information from existing wells located in the proposed storage zone and in surrounding formations that might be in communication with the storage zone;
(b) conducting the necessary tests to evaluate acceptable and safe operating conditions, e.g., the pressure and temperature of the storage operations;
(c) ensuring that the maximum operation pressure shall not exceed 90% of the fracture pressure of the storage unit;
(d) determining the injection rate, pressure buildup, and formation flow characteristics;
(e) evaluating the reservoir capacity. A material balance analysis shall be conducted to determine the reservoir capacity and to evaluate the storage zone’s ongoing containment ability and the nature of any external drive mechanism; and
(f) establishing a range of operating pressures and temperatures for the wells.

6.5.3 Operating and maintenance procedure audits

Audits of well operations and maintenance procedures should be performed yearly or as needed to ensure that processes and procedures adapt to any changes in operational or environmental conditions. It is possible that procedure audits will need to be revised as equipment ages.

6.5.4 Design and operations records

All design and operations records should be kept up-to-date for the duration of the project.

6.5.5 Measurement of injected CO₂

The CO₂ stream shall be continuously metered at the custody transfer or receipt point to the storage facility and to individual injection wells as follows:

(a) each meter shall be calibrated at regularly scheduled intervals and not less often than annually;
(b) the composition of the CO₂ stream shall be determined at regularly scheduled intervals and not less than annually;
(c) given the highly variable density of the CO₂ stream, meter runs shall measure pressure and temperature to allow for accurate metering;
(d) calibration records shall be maintained for accounting audit purposes; and
(e) injection volumes shall be recorded for production accounting and regulatory purposes and to allow monitoring and verification.

6.5.6 Recording management of change

Surface equipment should be maintained in accordance with accepted industry practice and local regulations. The mechanical integrity of piping and vessels should be maintained by the use of proper external and internal coatings, as necessary. As specified in Clause 6.1.5.1, if chemical methods are used for corrosion prevention, routine checking and maintenance of chemical performance should be performed as a safeguard against excessive corrosion.

Routine maintenance of valves, chokes, rotating equipment, and safety systems should be performed to ensure proper operation. Records of routine and preventive maintenance as well as repairs should be maintained by the project operator.

Note: See API RP 97 for further information on management of change.
7 Monitoring and verification

7.1 Purpose
The purpose of monitoring and verification (M&V) is to address health, safety, and environmental risks and assess storage performance. Monitoring, verification, and accounting activities support a risk management strategy that enables an assessment of storage performance and provides confidence that greenhouse gas reductions are real and permanent. “Monitoring” refers to measurement and surveillance activities necessary to provide an assurance of the integrity of CO₂ storage. “Verification” refers to a comparison of the storage project’s predicted and measured safe performance. Accounting allows the project’s avoided emissions to be determined and forms the basis for allocating storage credits. M&V supports accounting, but procedures related to accounting are not addressed in Clause 7.

7.2 M&V program periods

7.2.1 General
M&V programs shall be flexible and adapt to changes in storage or injection conditions as well as to the different periods of the project. They should also adapt to significant changes in the scientific understanding of the effectiveness of specific monitoring approaches. There are four generally accepted M&V periods which correspond to distinct periods in the project life cycle, i.e., pre-injection period, injection period, closure period, and post-closure period. Each of these periods has different M&V requirements that relate to periods in the project’s life cycle (Figure 1) and, as such, can require adaptation throughout the life of the project.

7.2.2 Pre-injection period monitoring
During the pre-injection period (which occurs before sustained injection starts and corresponds to the site screening, characterization, design, and development periods), project vulnerabilities shall be identified, solutions to mitigate recognized vulnerabilities shall be proposed, monitoring tasks shall be defined, and baseline monitoring data shall be acquired.

7.2.3 Injection period monitoring
During the injection period (which corresponds to the operational period and can also include pilot injection tests), monitoring activities shall be implemented to manage containment risks and storage and injection performance. Monitoring practices should be evaluated and adapted during the course of injection to ensure that monitoring activities continue to be appropriate and effective.

7.2.4 Closure period monitoring
During the closure period, monitoring activities shall provide sufficient information for managing containment risk, determining whether conformance with predictions has been attained, and for demonstrating the long-term integrity of the storage complex.

7.2.5 Post-closure period monitoring
During the post-closure period limited monitoring as required is maintained to verify that the storage complex is performing as predicted, and eventually to demonstrate that the containment risk has been reduced to a level where the need for further monitoring is eliminated. The post-closure monitoring period is not addressed in Clause 7 and if occurs responsibility will have transferred from operator to regulatory authority.

7.3 M&V program objectives
Project operators shall develop and implement an M&V program suited to their operation. The M&V program should be defined according to the project periods specified in Clause 7.2 and shall be designed to serve the following objectives:
(a) to protect health, safety, and the environment by detecting early warning signs of significant irregularities or unexpected movement of CO₂ or formation fluid
   (i) through gathering information on the effectiveness of containment of CO₂ throughout the project’s life cycle; and
   (ii) by providing sufficient evidence that the CO₂ has not moved beyond the storage complex, including leakage to a shallow subsurface zone or to the atmosphere;
(b) to support risk management throughout the project’s life cycle;
(c) to provide adequate information for
   (i) decision support within the project (among the project operators and principal project partners) and for communication with regulatory authorities; and
   (ii) communication with other stakeholders external to the project, including the local community or local landowners as appropriate;
(d) to test the predictions of dynamic modelling against observations documented from monitoring, enable adjustment of models to improve long-term storage performance predictions, determine the frequency and duration of monitoring activities, and support demonstration that criteria required for site closure are attained;
(e) to continuously improve the M&V program by adapting it to changing project circumstances, advances in best practices where appropriate, and advances in technology where appropriate;
(f) to support quantification calculations for injected and stored CO₂ in accordance with verification requirements identified for accounting purposes;
(g) to support management of CO₂ injection operations in a safe and environmentally responsible manner that complies with applicable regulations by gathering information that demonstrates that storage site operations are within the performance limits accepted by the project operator and the regulatory authorities;
(h) to support maintenance or improvement of storage system efficiency, safety, and economic performance;
(i) to support post-closure stewardship of the storage site (injection, closure and post-closure), including assisting in transfer of liability and responsibility in post-closure periods; and
(j) to support the achievement of project objectives and the preservation of project values additional to those specified in Items (a) to (i).

7.4 M&V program design

7.4.1 M&V program procedures and practices
The M&V program shall document
(a) the alignment of the M&V program with the project’s risk management policy, and shall include accountabilities and responsibilities for monitoring activities that support the risk management plan;
(b) reviews of monitoring tools and monitoring activity performance, as appropriate, to inform the need to make changes to the monitoring program (see Clause 7.3 (e));
(c) communication of M&V requirements to internal and external stakeholders as appropriate;
(d) the allocation of appropriate resources to provide an assurance that monitoring activities are carried out in a diligent and timely manner;
(e) the explicit purpose and performance metrics for all monitoring activities; and
(f) the procedures for properly documenting the monitoring activities and the processes implemented for evaluating monitoring performance against the original purpose and pre-defined operational metrics.

7.4.2 M&V program required specifications
The M&V program shall be based on the planned CO₂ injection operation and include the following:
(a) the projected volumetric capacity of the storage units within the storage complex;
(b) the injectivity of the storage units within the storage complex;
(c) the planned rate of injection of CO₂;
(d) the total mass of CO₂ to be stored;
(e) the boundaries of the storage complex, including stratigraphic definition of the storage units and primary and secondary seals;

(f) the locations of planned or existing wells that penetrate the storage complex within the predicted area of influence;

(g) the manner in which the M&V program will fulfill requirements imposed by applicable regulations;

(h) the schedule and reporting procedures to document compliance with M&V requirements in applicable regulations or as imposed by or agreed with regulatory authorities;

(i) the sensor systems and human observations that provide objective data on system behavior collected at a frequency sufficient to support efficient operation under normal conditions and to help prevent or recognize Health, Safety and Environment (HSE) impact under upset conditions;

(j) the process and frequency for reviewing the M&V program, which shall include assessing observed performance against predicted performance, responding to changes in assumptions, and incorporating project lessons learned and changes to best practices. The process shall consider
(i) the frequency of updates to the program when observed performance corresponds to predicted performance;
(ii) the frequency of updates to the program when observed performance does not correspond to predicted performance;

(k) the process and schedule for documenting M&V changes and updates;

(l) the risk-based ranking of scenarios that have the potential to cause significant HSE impact or to negatively affect storage performance, including the planned rate of injection, the total mass of injection, or the integrity of containment. This description should encompass the link between M&V design and any updated risk assessment results in compliance with the risk assessment criteria specified in Clause 5;

(m) all baseline measurements that have been obtained. Significant concentrations of CO₂ are commonly present in surface and subsurface environments and can vary daily or seasonally. Such normal fluctuations in baseline need to be determined to differentiate natural variations from leakage, as follows:
(i) at a minimum, baseline measurements shall be taken for every sampling position that will later be used for monitoring;
(ii) consideration should be given to having baseline measurements in areas where the anticipated pressure increases are sufficient to create a significant risk of leakage of reservoir brine into protected groundwater. In some cases this may extend beyond the CO₂ plume;
(iii) for surface-observable conditions subject to seasonal variation (e.g., soil gas determinations if chosen), a minimum of one year’s observations shall be taken to account for such variation;
(iv) concurrent meteorological conditions should also be tracked to properly document seasonal variations such as temperature, precipitation, and prevailing winds;

(n) the monitoring targets (or thresholds) for
(i) each ranked risk identified within the risk management framework;
(ii) identifying when there is a need for modifications to the numerical prediction models and monitoring protocols;
(iii) supporting verification data that criteria required for site closure are attained (see Clause 8);
(iv) managing CO₂ injection operations, including the composition of the injectate, the injection rate, injection volumes, and reservoir pressures;

(o) the design of the monitoring program at the surface, in the biosphere, between the biosphere and the storage complex, and in the storage complex, specifying the assumptions and expected conditions for which the monitoring program is designed, the parameter changes that the program is designed to observe, and the timing (frequency) and duration of monitoring activities for each monitoring target for each monitoring period;

Note: Examples of monitoring technologies include the following:
(1) at the surface: near-surface geophysical monitoring, tiltmeter monitoring, eddy covariance, Interferometric Synthetic Aperture Radar (InSAR), laser spectroscopy, gravity monitoring, electromagnetic surveys, hyperspectral imaging, soil gas surveys
(2) in the biosphere: resistivity surveys, instrumented monitoring wells for pH and water chemistry monitoring, soil gas flux monitoring
between the biosphere and the storage complex: repeat 3D seismic surveys, instrumented observation wells for pressure and temperature monitoring; repeat well logging; and
in the storage complex: repeat 3D seismic surveys, vertical seismic profiling, passive seismic monitoring, instrumented observation wells for pressure and temperature monitoring, downhole resistivity measurements, repeat well logging, tracer surveys.

the requirements for data acquisition from monitoring activities needed for integration into the project’s predictive modelling program and the frequency with which this integration will occur. This description shall also identify how monitoring and modelling jointly support the project’s risk management program. Predictive models shall be used with a description of the potential range of outcomes and should incorporate any associated degrees of uncertainty. The M&V program shall include a process for gathering and using information that could improve injection operational performance and storage safety;

the decision criteria based on monitoring performance indicators used to determine whether the storage complex is exhibiting behaviour outside the expected range of performance. The system of measurements and observations that comprise the monitoring performance indicator shall have sufficient accuracy and precision that changes in monitoring observations can be distinguished with reasonable certainty relative to the decision criteria. This requires that detection thresholds (in a single observed parameter) or conditions (in a set of parameters) within each monitoring performance indicators must be determined and identified;

the schedule and process for verifying both storage integrity and quantification of stored volumes of CO₂;

the performance measures (i.e., criteria for evaluating the success of the monitoring program) to be met by all periods of the monitoring program, with statements of justification and a level of detail appropriate for the objectives to be achieved.

7.4.3 M&V program recommended specifications

The M&V program should take into consideration and describe the following:

(a) the applicable performance measures and purposes of monitoring during the different periods of the project’s life cycle, the monitoring technologies that will be used during each period, the rationale for their selection, and any additional measurements or other data needed to support decisions involving monitoring activities. Technologies to monitor the following should be included:

(i) injected volume;
(ii) flow rate and injection pressure;
(iii) composition of injectate;
(iv) spatial distribution of the CO₂ plume;
(v) spatial distribution of the zone of elevated pressure;
(vi) pressure within the storage complex;
(vii) well integrity;
(viii) leakage outside of the storage complex;
(ix) integrity of the confining zone;
(x) extent of displacement of formation water in the formation;
(xi) pressure changes in the deepest permeable formation overlying the primary seal above the storage units; or permeable formations underlying the storage unit where achievable without increasing the risk of contaminating a subjacent aquifer.
(xii) potential induced seismicity or microseismic activity;
(xiii) geochemical changes in the reservoir that relate to risks from CO₂ injection or that enable validation of other observations such as those related to changes in permeability; and
(xiv) contamination of other potentially competitive resources that have been identified within an accepted area of review;

(b) the methodology used to select and qualify monitoring technologies. The following elements should be included:

(i) defining monitoring tasks;
(ii) identifying potential monitoring technologies;
(iii) evaluating the effectiveness of technologies against the required tasks;
(iv) estimating the life cycle risk reduction benefits of available technologies;
(v) estimating the life cycle costs of available technologies (if desired);
(vi) a description of the placement of observation wells, if part of the monitoring system, and all monitoring activities associated with each such well including a description of the methods involved in all continuous and periodic measurements to be performed;
(vii) the methods and frequency used to monitor changes in groundwater quality and composition from baseline conditions in the lowermost protected groundwater.
(viii) the identification and description of pre-existing wells in the storage complex that do not meet the requirements specified in Clause 6.3.7. A determination shall be made for each pre-existing well in the area of influence whether ongoing monitoring shall be required and, if required, a description of the monitoring methods to be used shall be included.

7.4.4 M&V program contingency monitoring
The M&V program should describe the following:
(a) pre-defined monitoring observations that would likely indicate conditions other than normal expected system performance. These observations will arise from (i) measurements taken from individual instruments or methods; (ii) qualitative observations; and (iii) combinations or sets of measurements and observations.
(b) pre-defined observations for all baseline parameters measured
(c) the operational changes more likely to be required, based on the occurrence of specific conditions other than normal operational parameters and the appropriate risk-based preparations to effect those changes;
(d) in the event of observations or conditions that are outside the anticipated range of parameters, the project operator’s first response plan to check, confirm, and retake the observations, to the extent possible;
(e) the project operator’s second response plan to follow up on the data checks specified in Item (d) in a broader sense to establish situational awareness based on all available information. The assessment of this information should be based on expert judgment, including experts from outside the project; and
(f) the project operator’s third response plan to develop a remediation strategy including, if necessary, reevaluation of risks, monitoring programs, and operations, based on the information gathered through implementing the second response plan.

Notwithstanding the project operator’s diligent efforts to pre-define observations that are standard versus non-standard, the project operator should remain vigilant for the emergence of observations and conditions that do not fall clearly into pre-specified categories. The operator should be prepared to implement an emergency response plan and establish an emergency response zone in a priority area if immediate response actions are required in the event of an emergency.

Procedures should be documented to address situations arising from non-standard project conditions such as may require the establishment of a consultation panel of independent qualified experts.

8 Closure

8.1 General
The purpose of Clause 8 is to provide guidance to and establish predictability for project operators and regulatory authorities regarding the expectations of the post-injection closure period. The intentions of the closure period are to demonstrate the following:
(a) sufficient understanding of the storage site’s characteristics;
(b) low residual risk; and
(c) adequate well integrity.  
**Note:** These objectives are not intended to replace requirements related to transfers of liability and responsibility under applicable regulations. Examples of criteria for transfers of liability and responsibility are provided in the EU CCS Directive [insert EU CCS Directive Reference] and in the rules of the US EPA UIC program for Class VI wells [insert EPA SDWA UIC Reference].

8.2 Activities  
Immediately upon the project operator’s termination of CO₂ injection, the closure period begin.. The activities included in this period are as follows:
(a) Risk management (Clause 5):
   (i) implementation of all required elements of the risk management plan (Clause 5.5); and
   (ii) planning and review of risk treatment (Clause 5.7).
(b) Development — Operations and maintenance (Clause 6):
   (i) abandonment and closure of injection and monitoring wells not intended for post-injection use (Clause 6.3.7); and
   (ii) operation and maintenance of remaining monitoring or remediation wells (Clause 6.5).
(c) Monitoring and verification (Clause 7):
   (i) implementation of the post-closure stewardship and monitoring requirements for the post-injection period (Clause 7.4.2); and
   (ii) ensuring that plume characteristics are as expected (Clause 7.4.4).
(d) Modeling
   i. Dynamic modeling and appropriate model calibration against observations (history matching) to predict the evolution of the CO₂ plume and the associated elevated pressure zone, support continued risk analysis, and enable demonstration of the requirements listed in Clause 8.4.1.

It is envisioned that at the end of CO₂ injection, the project operator will use the post-injection period to prepare the site for the transfer of responsibility and liability, with the intention of transferring all rights, obligations, and liabilities associated with the site to a designated authority. When this occurs, the site is said to achieve “closure”. It is only at the point of transfer of responsibility and liability that a site achieves “regulatory or permitted” closure status.

It is possible for a project operator to not transfer liability or responsibility for a site to a designated authority or responsible entity. In this case, the site will not achieve the milestone of site closure and will not enter the post-closure period, but will remain in the post-injection closure period.

8.3 Post closure period plan  
The project operator shall develop a closure period plan for the storage site. The plan shall outline the process for meeting applicable criteria to enable the site to enter the closure period. The main parts of the plan should be as follows:
(a) specification of provisional criteria for closure operations, including
   (i) the requirements specified in the storage permit;
   (ii) site-specific performance targets for site closure, as agreed to with the regulatory authority; and
   (iii) the conditions for site closure specified in applicable regulations;
(b) specification of the provisional site closure qualification process and timing;
(c) provisional plans for site decommissioning, including plans for plugging and abandonment of wells and decommissioning of surface facilities associated with CO₂ injection and monitoring operations; and
(d) provisional plans for closure period monitoring and remedial activities required by regulatory authorities.

The post-injection closure period plan shall be updated as appropriate during the project’s life cycle, as specified in Clause 5.
8.4 Post-injection and closure period qualification process

8.4.1 Requirements
The closure period qualification process should follow a structured and transparent approach, ideally a joint effort between the project operator and designated authority. The process shall be designed to identify compliance with individual risk and uncertainty risk management, specifically that risks and uncertainties have been gradually minimized and managed throughout the storage project’s life cycle. The requirements shall be as follows:
(a) to understand the total CO₂ storage system sufficiently to detail how its future evolution can be assessed with a high degree of confidence. Clauses 6 and 7 shall govern the methods by which data are collected and used to understand the total system. One recognized component for ensuring sufficient understanding of the total system is to understand the pressure aspects of the system. Specific component considerations shall include the following:
   (i) an understanding of current and future CO₂ plume dispersion and migration.
   (ii) an understanding of reservoir pressure evolution based on time series measurements;
   (iii) an understanding of the pressure decay over time, specifically as compared to elevated reservoir pressure (taking into consideration the fact that a change in pressure is not an appropriate metric to specifically denote non-compliance);
   (iv) an understanding of the implications for longer-term pressure evolution models (e.g., the CO₂ pressure wave described by acceptable methods); and
   (v) an understanding of the displacement, and any substantial compositional changes, of formation water;
(b) that risks and uncertainties have been reduced to a level where future negative impacts on human health, the environment, or economic resources are unlikely. This shall be accomplished by using the processes and plans specified in Clause 5 which will be used to evaluate the spread in performance predictions since cessation of injection, obtained using a set of model realizations (feasible dynamic models), to show a converging trend and that the uncertainty band on the predictions of CO₂ plume migration and pressure development is within acceptable limits; and
(c) to ensure well integrity by following the processes specified in Clauses 5 to 6.

8.4.2 Process
The site closure qualification process should comprise the following actions:
(a) a dialogue between the project operator and regulatory authority expressing the intent of ceasing injection, initiating execution of the site closure plan, and finalizing site closure performance targets;
(b) compilation of requirements for site closure, including
   (i) the requirements specified in the storage permit, updated as appropriate throughout the life of the storage project;
   (ii) site-specific performance targets for site closure, updated as appropriate throughout the life of the storage project and agreed upon by the designated regulatory authority; and
   (iii) conditions for site closure, in accordance with applicable regulations (including wells selected for abandonment);
(c) preparing a plan to demonstrate compliance with the requirements for site closure, including plans for collecting, reviewing, assessing, and structuring the information necessary for obtaining permission to initiate execution of the plans for site decommissioning;
(d) compilation of reports, results, and other data that will form the basis for the site closure assessment, including
   (i) operational logs that document the history of storage site operations;
   (ii) monitoring logs that document and map the history of monitoring and verification activities;
   (iii) an updated project risk database showing how significant individual risks that have been analyzed and managed have evolved throughout the life of the project, including a description of the reasons for upgrading or downgrading risks during the life of the project;
(iv) a description of how key uncertainties have been analyzed and managed throughout the life of the project and a retrospective review of key decisions made under risk uncertainties;
(v) compilation of project performance targets, including a record of changes made during the life of the project and a description of the reasons for those changes;
(vi) compilation of results and conclusions drawn from monitoring, modelling, and risk assessments to support a demonstration of compliance with site closure requirements, including a description of how geological, geochemical, and geomechanical characterization and flow simulation models have been calibrated or adjusted; and
(vii) a description of historical storage performance relative to predictions from modelling and simulations;
(e) updating of storage performance predictions and identifying potential residual health, safety, and environmental risks, including potential risks to future containment stemming from well abandonment and site decommissioning;
(f) updating of the environmental impact assessment, including potential impacts from site decommissioning;
(g) verification of storage performance predictions and environmental impact assessments; and
(h) assessment of compliance with site closure conditions.

8.5 Decommissioning

8.5.1 Preparation

As the site moves into the closure period, aspects of the project beyond injection shall be considered. The two major components, i.e., wells and surface facilities, should be prepared for appropriate post-injection and closure actions as follows:
(a) preparation of plans for ongoing site monitoring as required by applicable regulations and with the objectives of identifying migration of CO₂ out of the storage unit, any leakage at the surface, and impacts from migration of formation fluids. This should include
   (i) identification of monitoring technologies appropriate for the site; and
   (ii) a timeline for site surveys;
(b) identification of appropriate corrective actions to address the most likely events identified from modelling of the storage unit required during the closure qualification process, which should include fluid migration (CO₂ and/or formation water or hydrocarbons) via wells;
(c) preparation of plans to notify future landowners and (if applicable) resource owners of the storage site and remaining subsurface infrastructure; and
(d) identification of the entity responsible for undertaking the post-closure stewardship plans, including contact information for the public.

8.5.2 Wells

As part of the post-injection closure plan, the project operator shall have a provisional plan for decommissioning injection and monitoring wells to ensure that the wells do not allow fluid movement between zones and will continue to safeguard protected groundwater aquifers. The plugging and abandonment of wells shall conform to this plan, be performed in accordance with the requirements of the regulatory authority and Clauses 5 to 6, and take the following into consideration:
(a) isolation of all existing storage zones from the immediate wellbore area;
(b) isolation of all zones of usable-quality water;
(c) prevention of migration of CO₂, hydrocarbons, or water from one horizon to another;
(d) provision of a sufficient cement seal and prevention of fluid movement through any channels adjacent to the wellbore;
(e) maintenance of the integrity of the cement and cement additives;
(f) isolation of all formations bearing oil, gas, geothermal resources, and other valuable minerals from zones of usable-quality water;
(g) prevention of escape of oil, gas, or other fluids to the surface or to zones of usable-quality water;
(h) separation of porous and permeable formations from other porous and permeable formations;
(i) separation of lost circulation intervals in the well from other porous and permeable formations;
(j) isolation of the surface casing (or intermediate casing) from open holes below the casing shoe;
(k) sealing of operator-installed wells at the surface;
(l) mechanical integrity of legacy wells; and
(m) post-closure isolation of injected CO₂ or displaced fluids (including brine and hydrocarbons) from all usable groundwater, economic deposits, and soils, and from the atmosphere.

8.5.3 Surface facilities
All surface facilities and equipment associated with the storage project that is not intended for post-closure monitoring or contingencies should be removed in agreement with the designated authority. All facilities in the storage site required by regulatory mandate shall remain and be maintained in a manner consistent with best practices and all applicable legal and regulatory requirements.

8.6 Post-closure stewardship
Post-closure stewardship is defined by this Standard as the “post-closure period”. By definition, this period is not part of the Standard. Therefore, the “post-closure period” is acknowledged as a part of a process which is marked by the transfer of responsibility and liability, but is not contemplated by this Standard.