INTRODUCTION

The geological storage of carbon dioxide (CO_2) may enable real progress in the global effort to make meaningful near-term reductions in greenhouse gas (GHG) emissions especially from large-point source emitters such as power plants, refineries, cement plants and steel mills. Carbon Capture and Storage (CCS) is not a panacea, but it does offer a tangible means to deal with large volumes of gas emissions by using technologies already in-hand, and improving them.

CCS is a bridging technology during the transition to an alternative energy future. Optimism for its success is based on industrial experience, but even proponents acknowledge that there are several issues that need to be addressed before it can achieve widespread application. Key issues are reviewed in brief below, and are addressed in detail in the remainder of the document.

Typically, CCS or CO_2 capture and storage is defined as the integrated process of gas separation at industrial plants, transportation to storage sites, and injection into subsurface formations. US government agencies will use the word "sequestration" instead of "storage", but the meaning is the same and the acronym for all, including many international organizations, is CCS. When CO_2 is stored or sequestered, it is injected into the pore space of rocks deep in the earth's subsurface (at depths typically greater than 1,000 meters) and carefully designed operational protocols are observed to provide for safe operations. Once the CO_2 is safely injected in the ground, it is expected to remain there for a geological period of time.

Drawing on the wide variety of practical experience in the oil and gas industry, this document addresses key technical aspects and technological innovations used in the geological storage of CO_2. The text cites numerous examples of projects comparable in size and scope to large CCS operations. The document is not a comprehensive review of geological storage or industry best practice, but in its four chapters addresses frequently discussed areas where there is likely to be particular value in sharing industry knowledge.

Chapter one examines fundamental questions:

- How is a storage site selected?
- What criteria matter most and what data is collected to evaluate objectively the suitability of a proposed site?
- What makes some locations inherently better choices than others for storage based on geological context, knowledge and data availability?
- What processes make it geological storage?

The second chapter focuses on wells and the potential for CO_2 to leak from existing wells into aquifers or to escape to the surface due to open conduits or cement deterioration. The issues surrounding well integrity, cement and well construction techniques for wells exposed to CO_2, and results from recent field and laboratory experiments are discussed.

Analysis suggests that due diligence coupled with proper well testing and good science, transforms this potential problem into a very manageable issue. However, for some sites, the remediation required to fix problem wells may render these sites economically undesirable.

The third chapter examines monitoring and verification techniques. Effective monitoring is accomplished mainly through data acquisition and establishing systems to model the position of CO_2 in the subsurface. By design, monitoring addresses key questions about potential concerns and provides substantial project performance data. A good monitoring program will serve to avoid potential problems as opposed to providing indication of problems that have already occurred.

The issues arising from operations and eventual closure of a storage site are assessed in Chapter 4. Some regulators have considerable experience with the closure of oil and gas operations. Based on those practices, practical regulations can be created that provide realistic assurance that the process will be safe and effective. In addition, the maximum storage potential of given systems and what this means for injection rates and pressures is examined.

The CCS process is similar to the natural gas business running in reverse. It is worth noting that CO2 is non-flammable, non-toxic and not dangerous except in high concentrations. The entire biosphere depends on CO2 for life. In the atmosphere, it disperses very quickly. The challenge of managing gas like CO2, deeply buried in the subsurface, is not without precedent and experience. A successful CCS program will ultimately depend on the establishment of standards and expectations to provide a framework for operators, governments and the public, to ensure there is no harm to life, water or the environment.

CCS is an efficient way to deal with emissions from fossil fuel combustion. Eventually, CCS may be implemented at power generation facilities that use waste biomass feedstock. Storing the CO2 released by the combustion of biomass could create a process even more effective than renewables for reducing atmospheric CO2 loads. This scenario offers the prospect of generating power and taking net CO2 out of the air at the same time – not utopia, just progress.

Large commercial-scale CCS projects are rare today because the basic business fundamentals are lacking. In most jurisdictions, it is not yet legal to carry out CCS, with the exception being enhanced oil recovery (EOR) operations. More importantly, there is no mechanism to monetize reduced CO2 emissions using CCS. For a company selling a commodity (such as electricity, power, oil, gas, refined products, cement, or steel), embarking on CCS on a unilateral basis makes no business sense. Until stored CO2 has commercial value, this is unlikely to change.

Fortunately, several jurisdictions around the world are beginning to assemble the required legal and regulatory frameworks to enable CCS by amending existing regulations and creating new ones. Industry already has the technology, skills and capabilities to execute industrial-scale CCS projects, and the commercial reason to deploy the technology looks likely to materialize.

Operators of CCS projects will need:

- Access to quality storage sites and unambiguous rights to use storage space.
- A legal framework and license process to grant permission to inject.
- Financial institutions willing to provide normal business financing facilities.
- Clear expectations for eventual legal project closure.
- Management of the long-term responsibility for the stored CO2 (stewardship).
- Expectation of a reasonable return on investment.

Individual CCS projects are likely to have four distinct phases with regulatory transitions:

- *Site selection and development* (approximately 5-10 years): The site is identified based on a geological evaluation, commercial factors and regulatory expectations. Space for surface facilities is secured and primary subsurface storage space is purchased or leased from its owner (an entity or government). A permit to store is granted, infrastructure is constructed (e.g. wells, flowlines, compressors), and operational capacity is verified.
- *Operation* (over decades): The entire period of gas injection, plus some years of additional monitoring, as technically appropriate.
- *Closure* (over years): This phase begins when sufficient monitoring indicates that the injected CO2 has been well-managed and should cause no problems. Regulators may choose to maintain observation wells or other facilities for very long time frames. Most wells are plugged and the infrastructure is removed. The site is then considered normal.
- *Post-closure*: The expected permanence of CO2 in the reservoir is established. The operator is no longer involved.

There are risks. For CCS to succeed, risk must be managed objectively and responsibly by both operators and regulators. It is possible to over-regulate falsely perceived risks and under-regulate real but unrecognized dangers. Having the right regulatory mix will help the CCS process succeed. It is an important technical consideration that "risk" associated with injected CO2 is not constant with time. The probability of an unexpected event increases as injection volumes and subsurface pressure ramp up and this requires close monitoring during the operations phase. After injection stops, as pressure equilibrates, and natural trapping mechanisms take effect, the injected CO2 becomes progressively more immobile.

For operators and regulators, the most effective way to minimize unexpected consequences is to start with wisely-chosen storage sites. The factors that make a site a good and safe place to inject and store CO2 are the subject of Chapter 1, on site selection. Then sound practice must be used to construct the storage project, especially construction of new wells and evaluation and/or remediation of existing wells, the technical basis for which is discussed in Chapter 2. Monitoring of the project, including both baseline and operational measurements, is key during the operational phase to optimize performance and catch potential problems early; as discussed in Chapter 3. Finally, a successful project will integrate intelligent design, strong operational controls and robust planning including the operator and regulators to enable a smooth transition into the closure and post closure phases, as explained in Chapter 4.

CHAPTER ONE: Site characterization

Subsurface characterization is a fundamental step in identifying potential geological units for CO_2 storage. It starts with solid geoscience, using routine and established techniques to evaluate data. While some degree of uncertainty is inevitable when characterizing the subsurface because of inherent natural variability, three elements are essential for geological storage to be technically feasible. The potential storage unit must have sufficient pore volume to store all the injected material ('capacity'); the formation characteristics must allow near wellbore injectivity ('injectivity'), and an overlying sealing package must ensure the containment of appropriate fluids ('containment'). In this context "fluids" refers to CO_2 in a number of chemical phases including supercritical (dense) phase, gas phase, and CO_2 dissolved in saline brines.

Capacity is determined by five parameters, namely the formation thickness, the area of the storage site, rock porosity and CO_2 density (which could vary even in a single given reservoir), and storage efficiency (a factor which reflects the fraction of the pore volume that can be saturated with CO_2 plus the capacity of existing formation and fluids to have CO_2 in solution or chemical compounds. A key selection parameter is porosity.

Injectivity is determined by the permeability of the formation and the design of the injection well. Ideally, CO_2 storage requires high permeability near the wellbore to enable to the CO_2 to move quickly into the pore space. As injection progresses, geochemical reactions between subsurface CO_2 and rocks and fluids in the storage formation could favorably or unfavorably change injectivity. Containment requires some form of trap and a competent seal. Seals are natural barriers to flow, which means rocks having minimal permeability or capacity to allow flow and layers without interconnected faults or fractures that would allow significant seepage. Seals can be vertical or lateral. In some cases a single seal will provide great containment, in others multiple sealing layers will be preferred, to act as a total sealing package. The effective quality of sealing rocks can be quantified and calibrated with laboratory data. The continuity of the seal is important. It needs to cover an area sufficient to contain the total volume to be injected and it should be appropriately thick enough to prevent any potential breach due to adverse geochemical or geo-mechanical effects that might occur under certain specific circumstances. Residual saturation can act as a powerful trapping mechanism for CO_2.

There are several generic modes of geological CO_2 storage. These include storage in:

1- depleted oil and gas reservoirs, which offer some of the most readily-available and suitable storage solutions;
2- deep saline formations, which may have greater regional coverage and are much more common., and may be the only opportunities near many CO_2 emission sites;
3- association with oil and gas industry Enhanced Oil Recovery (EOR) projects;
4- coal bed formations.

The main advantages of storage in the vicinity of producing oil and gas fields is the maturity of the initial database which will have been developed from the oil and gas operations, and the reasonable certainty of proven containment.

Understanding the mechanisms by which CO_2 is trapped is an important aspect of site characterization. Physical and geochemical factors determine the effectiveness of trapping mechanisms. Basin-scale aspects, including the regional structure of the basin, its history, and its pressure regime are important, as each formation will invariably be part of a larger system for which basin-wide fluid flow and storage mechanisms need to be understood. Ascertaining the direction and rate of natural fluid flows in the vicinity of the potential storage site is essential. Physical trapping mechanisms, comprising the geometry of structural and stratigraphic traps, are generally well-understood from routine reservoir appraisal in oil and gas exploration. Residual CO_2 trapped in the pore space within rock formations can also act as a trap and hence form an important storage mechanism. Geochemical trapping, in which CO_2 reacts with natural fluids and minerals in the subsurface (such as in the brine within a saline formation) can also lead to permanent CO_2 storage in the subsurface.

There are three generic phases of work, common to subsurface characterization activities in oil and gas exploration and production that can be applied to CO_2 storage. The first phase, site selection, involves regional screening studies to identify potential areas for the injection and storage of CO_2. The objective, taking account of analysis, modeling and risk assessment, is to identify one or more sites for detailed site qualification. Site qualification, the second phase, involves detailed subsurface studies to demonstrate the feasibility of injection and storage. This stage will typically include appraisal drilling (if appropriate wells do not already exist) and more detailed data acquisition, baseline testing to assist planning for future monitoring, and detailed risk assessment. The third phase, the development phase, involves further refinement of the field development plan and understanding more precise details of the target formations such as their petrophysical properties or injection capacity.

As is well-understood in the context of geological assessment and oil field development, a level of risk and uncertainty is inherent and must be accepted in decision-making about site selection and qualification for CO_2 storage sites.

Many of the best practices used in oil and gas reservoir characterization can be used to assess the potential of CO_2 storage sites (such as using seismic data, stratigraphic mapping and facies analysis to develop 3D geological models). Many geoscientists will consider the task of identifying high quality CO_2 storage sites relatively routine using applications of existing knowledge and practices. To be objective, selection criteria for extremely robust storage potential is not so challenging. Many of these will simply be depleted hydrocarbon fields. However, there will be strong economic pressure to select sites without the huge benefit of subsurface knowledge gained from oil and gas industry operations, and where geologic facts to predict storage efficiency are not so well known. These will require more care, significant acquisition of new data and will benefit from learning gained from early pilot and demonstration projects.

The oil and gas industry has a strong history of innovation and adapting while performing to high standards. It has highly sophisticated standard practices to solve problems. Investments in storage sites will also drive investments to improve site selection criteria and monitoring techniques. Some key modeling tools will be upgraded for CO_2 and storage application so that they are more effective and efficient for this specialized purpose. For instance, modeling the physics of CO2 movement *in situ* is not as fully defined as modeling the physics of typical oil and gas behaviors especially in large reservoirs with multi-phase fluid mixing; although sophisticated mathematical models exist to describe CO_2 related phenomena. There is also comparatively little data relating to many deep saline formations currently under study because they have not been of interest to oil and gas production. Other industry standard tools will benefit from CO_2 specific upgrades and advanced calibration, especially tools for large scale containment analysis.

CHAPTER TWO: Well construction and integrity

All stakeholders in CCS projects are likely to agree that it will be essential to evaluate the potential risk of CO_2 leakage in well bores at the storage site, and this applies to new and pre-existing well bores. Avoiding leakage is a standard part of oil and gas operations, and a major objective of the design basis of both injection and production wells. Serious efforts are made to verify the physical and mechanical integrity of wells. Techniques to prevent, detect and remediate leakage are standard practices. The oil and gas industry has decades of experience constructing and operating wells for the injection and production of CO_2 and CO_2 mixtures with oil, water and natural gas.

Extensive CO_2 specific well construction experience has been gained in CO_2 based EOR projects[1], the first of which began in the 1970s and also from the production of mixtures of natural gas with high CO_2 content. This activity has generated a substantial body of practical experience and corresponding analysis. Clearly wells designed for an environment exposed to CO_2 require understanding of the conditions of the well's service life, its abandonment, the physical features of the well itself (such as the choice of construction materials and practices to ensure internal and external sealing integrity) as well as geological and chemical characteristics such as the pressure, temperature and production / injection chemistry when the well is operating.

While some laboratory tests have shown that some cements commonly used in well construction may be vulnerable to CO_2 attack under simulated laboratory conditions, a larger body of laboratory work, field applications, performance history and studies indicate that normal oil field cements with good mixing, testing and placement practices are effective for CCS applications. Experience also suggests that effective placement of cement in the wellbore annulus is equally, if not more important in ensuring the well's integrity. A recent study carried out by the CO_2 Capture Project, which evaluated the barrier conditions of a wellbore exposed to CO_2, found that Portland-based cement and carbon steel provided an effective barrier to CO_2 and that cement placement was more significant in resisting CO_2 migration along the barrier system than the choice of cement itself.

Before constructing wells, the drilling, completions, operations and abandonment needs should be captured in a 'Basis of Design' and development plan. This will cover a wide range of considerations including the expected duration of each stage of a well's life (through site selection, operation, closure and post-closure); the injectant specification (rate, pressure, volume and composition) together with the corresponding reservoir characteristics; the number and type of wells required; the well completion types required; the barrier system components; corrosion mitigation ; a corrosion and monitoring program and plan; safety systems; servicing and maintenance requirements; and performance monitoring arrangements and injectivity maintenance and enhancements.

It is clear that the large volumes of CO_2 being targeted for injection in order to manage GHG emissions will require a very large number of new wells to be drilled and this highlights the need for good understanding of well specifications and best practices during site selection and development. Fortunately, recent advances in well technology, such as horizontal drilling, massive hydraulic fracturing, and multi-lateral wells will enhance the potential for individual well injectivity, and reduce the number of wells required to inject a volume of CO_2 compared with traditional drilling techniques common in early CO_2 EOR projects.

Existing wells can be used for geological storage of CO_2 and provide a valuable opportunity to use available infrastructure. Consideration of whether to use existing wells requires review of original design features, and scrutiny of their history of use (including plugging and abandonment history, where relevant). Baseline information, about the well and also about the relevant reservoir conditions (such as pressure, temperature, fluid / gas saturation, water chemistry) is also necessary. Re-using existing infrastructure for a purpose different from the originally intended design may result in operational limitations that are restricted compared with a new-build facility, but in most cases a well designed to inject CO_2 for EOR will be identical to one designed to store CO_2 at the same site. In general any well with robust design and execution and appropriate consideration of CO_2 requirements can be converted for CO_2 use.

New wells provide the opportunity to plan a barrier system tailored specifically to CO_2 and the conditions of the storage site. This may or may not be a significant decision point. Factors such as the barrier quality for the life of the well, the state of the reservoir, and the particular CO_2 storage requirements should be taken into account when planning. The fundamental requirements in planning new wells – a Basis of Design, a storage schedule, a development plan, and baseline surveys are the same as those required for existing wells.

CHAPTER THREE: Monitoring

Geoscientists think of subsurface monitoring as a fit-for-purpose data collection process done as part of a scientific evaluation designed to test effective understanding of complex subsurface relationships and verify expectations for the location and movement of fluids and gas with time. Monitoring provides a key performance indicator for secure storage, but it is wrong to think that monitoring in itself can guarantee safety. Monitoring is like the speedometer on a car. It contributes to safety but other factors are more important such as the design of the car itself, road conditions and how it is driven. The UN IPCC suggests that the proportion of CO_2 retained by an appropriately selected and managed site is likely to exceed 99% over 1000 years. So the key to secure storage is appropriate selection and management of the site and effective monitoring is fundamental to the overall process. Direct monitoring tools and techniques can be used to measure concentrations of CO_2, near well bores in the subsurface or by taking surface measurements however, most monitoring will be undertaken by indirect measurement methods such as seismic, gravity or electromagnetic surveys. A range of tools already exist to carry out monitoring activities, and careful selection needs to be made to ensure the right tools are used for the right task, taking account of local , site-specific conditions. In most cases, complex 3-D computer models are built that serve as proxies for visualization and quantification of the subsurface environment. Information from monitoring helps refine and improve these models.

3-D seismic imaging is extensively used in the oil and gas industry for depicting geometries and distributions of rock volumes, relative pressures and fluid types. It is an extremely sophisticated and powerful tool and through the introduction of time-lapse technology ('4-D' seismic imaging) is being further refined. . Even so, seismic imaging has limitations such as the technical challenges of creating quality seismic images through layers of salt, or the financial challenges and land-use access issues inherent in carrying out seismic imaging on land. In some cases the technique may not provide the relevant data. Gravity measurements, which reveal changes in density for a theoretical vertical column of rock, are another indirect measurement tool likely to be applied at CO_2 sites. Satellite-based applications are also being used to detect alterations in ground elevations – capable of detecting changes in vertical elevations of one millimeter – ground uplift or subsidence that that can be attributed to changes taking place in the subsurface.

These techniques are being used now in commercial-scale projects and operations in oil and gas operations in different parts of the world. The In-Salah partnership, for example, has made good use of satellite monitoring techniques to monitor CO_2 injection in the desert of Algeria [2]. The Sleipner CO2 storage site has demonstrated the value of 4-D seismic and gravity for monitoring CO_2 movement [3]. Comprehensive 3-D and 4-D seismic imaging has been deployed in the Vacuum Field within the Permian Basin in New Mexico [4] and at the Kuparuk field in the North Slope of Alaska. Gravity monitoring, 3-D and 4-D seismic technologies have been employed at the Prudhoe Bay field in Alaska [5] and have helped assist recovery from the field for many years. A range of technologies have been used at the Pinedale field in Wyoming to aid understanding of the distribution and concentration of natural gas within the field and how this changes with time. At the Peace River operations in Canada, seismic, micro-seismic and tiltmeter monitoring programs have been conducted over a period of years to improve understanding of the dynamic behavior of the reservoir.

Whatever monitoring techniques are selected, it is important to have a good base line survey before injection starts and understand the resolution potential of the technique and the implications at the specific location.

CHAPTER FOUR: Development, operation and decommissioning

Similar to the areas of site characterization, well construction, and monitoring the oil and gas industry has extensive experience in managing, operating and decommissioning fields and subsurface installations. Life cycle assessments into aspects of field operations have been conducted and widely accepted principles of effective management of health, safety and environmental issues have been established. Guidelines, best practices, certification frameworks and regulatory proposals for the CO_2 storage lifecycle have been proposed by a range of organizations internationally.

Oil and gas industry operations have for many years been informed by the concept of a ‘feedback loop’ in which operational and monitoring data inform continuous improvement to the earth and dynamic models which characterize the system. This in turn drives operational response. Feedback is also a key concept in performance-based decommissioning so that the closure and post-closure phases of a storage project are able to begin from the starting point of a highly-characterized and well-understood system.

The development of CO_2 storage fields will parallel the development of oil and gas fields in many ways and drawing from this extensive experience will be key to success. Field re-development for CO_2 storage will learn from the experience of the oil and gas industry in re-developing mature fields for installation of water flood and EOR projects. The lessons of phased development and ‘learning through development’ should be considered in planning for CCS deployment and in the development of regulations. As with oil and gas field production, optimal development of a CO_2 storage facility is in the best interests of the operator whether or not specific, and clearly-defined regulations exist.

Field planning and development involves using the earth and dynamic models developed during site assessment to determine the well count, well type, injection strategies and operational parameters (especially pressure). Advanced well designs, such as horizontal and multilateral wells, may be used in CO_2 storage to improve individual well rates, reduce near wellbore pressure impacts, and control distribution of CO_2. Reservoir characteristics will have an impact on the well count and density and will also affect the injection strategy. Operational parameters, such as well rates and pressures, will inform well construction and infrastructure design. Arguably the most important parameter for CO_2 storage projects is the maximum bottom hole injection pressure, where the goal is to maximize the injection rate without compromising the integrity of the containment system.

Project design considerations of this kind can draw on oil and gas industry workflows and practices. Dynamic reservoir modeling can be used to develop geological scenarios which enable an optimal design to be developed. This in turn will support the creation of a cost-effective monitoring plan.

In monitoring well integrity, cement evaluation logs can be used to assess the integrity of the well’s sheath of cement in the annular space between the casing and the formation. Sonic and ultrasonic evaluation tools can also be used. The information they provide will be one important source of data, in addition to drilling reports, drilling fluid reports, open hole log information, and cement placement information.

A number of factors, such as the presence and concentration of oxygen, CO_2 and hydrogen sulfide (H_2S) and the anticipated life and service of the equipment, need to be taken into account when determining the materials that should be used in well completion equipment. There is extensive industry experience of materials selection in well construction for CO2 exposure, including lessons from planning CO_2 storage projects such as the Gorgon Gas project in Australia. This has considered, for example, the levels of H_2S contained in the CO_2 gas stream and its impact on choice of steels including stainless steels, and the capacity of non-metallic seals to to perform in this extreme environment . The Rangely Weber field, in Colorado, provides an example of where wells constructed in the 1940s have been studied and have been successfully used for CO_2 storage.

During the well operations phase, various techniques can be employed for monitoring well integrity. Mechanical integrity tests can be used to ensure the seal is intact. Pressure/ temperature logs, noise logs, thermal decay time logs and cement evaluation logs can also be used. Where necessary, remediation and repair can be carried out, and on occasion wells may need to be completely decommissioned.

Monitoring initiatives remain an important part of the operations phase. Monitoring will seek to ensure not only that the well is performing as intended and is being operated and maintained within its design parameters at an acceptable level of risk over its design life. but also in the case of CO_2 storage, that it is being operated in a manner which reduces the risk of uncontrolled CO_2 release. A comprehensive monitoring program will include defining maximum and minimum pressure limits to all annuli and application of a wide variety of diagnostic testing techniques. These would include approaches such as annulus fluid or gas analysis, or using a wide variety of logs including leak detection logs, video logs, ultrasonic noise logs, temperature logs, pipe inspection logs, tubular inspection logs, and caliper logs. Equipment should also be inspected when removed from a well. All monitoring and inspection data should be managed so that relevant integrity data is readily accessible and can be used to support decision-making.

The operational phase of a CO_2 storage project is not a static period, but one in which there is ongoing monitoring, learning, and action when necessary. Operations generate learning about the subsurface and provide valuable operational results and monitoring data. Engineering, geo-technical and operations staff will work together to monitor and manage day-to-day performance. Production and reservoir engineering staff will similarly scrutinize operational data to interpret well and reservoir performance, and will assess the movement of the CO_2 plume. Actions during operations might include corrosion maintenance programs, well maintenance, making modifications to the injection strategy, and updating and enhancing the project's geological model on a regular basis. Documenting operations management, in which important issues are logged and potential risks and management responses are outlined, is a good practice and provides a robust foundation of information for eventual decommissioning.

Decommissioning of CO_2 storage facilities can draw on the experience of the oil and gas industry in decommissioning depleted fields. Requirements for this phase will also be set out in regulation. It is appropriate that the project operator maintains responsibility for the CO_2 plume for a period following the end of injection. The duration of this responsibility will depend on the size, type and risk profile of the project, drawing on knowledge of the subsurface CO_2 behavior already observed., By the end of injection, with a well-calibrated model of the subsurface environment and the CO_2 plume, it is likely that robust predictions for the long term position of the CO_2 can be made for many years into the future. Residual risks, such as encountering faults in the subsurface containment area, can be quantified and modeled. Overall, the technical expectation is that long term containment is achievable and can be modeled and demonstrated without any expectation requiring long term actions and interventions. Safeguarding the public and protecting the environment is paramount, and this can be achieved recognizing limits to the project operator's responsibility to a reasonable period customary for large private and public works. In determining this balance, consideration can be given to a number of emerging frameworks which consider long-term stewardship issues.

During the closure phase, the focus is on long-term containment and isolation of the injectant with the natural and engineered systems. Consideration will be given to the potential deterioration of materials due to long-term CO_2 exposure, which has an impact on the materials selected for use in decommissioning. If material performance can impact long term containment, this will be mitigated by material choice.

In the post-closure phase, no further action is required if the site has performance in accordance with reasonable expectations of stability in earlier phases. Where there is less than expected site stability, monitoring and remediation where necessary, should be continued until stability is achieved.

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