TECHNICAL ASSESSMENT OF GEOLOGIC CARBON DIOXIDE (CO_2) STORAGE: BEST PRACTICES DERIVED FROM PHASE III OF THE PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PROGRAM, 2007–2018

Plains CO_2 Reduction (PCOR) Partnership Phase III
Task 13 – Value-Added Report

Prepared for:

William Aljoe

National Energy Technology Laboratory
U.S. Department of Energy
626 Cochrans Mill Road
PO Box 10940
Pittsburgh, PA 15236-0940

DOE Cooperative Agreement No. DE-FC26-05NT42592

Prepared by:

Neil Wildgust
David V. Nakles
Nicholas W. Bosshart
Loreal V. Heebink
Charles D. Gorecki

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

December 2019
Approved

2019-EERC-12-18

EERC DISCLAIMER

ACKNOWLEDGMENT

This material is based upon work supported by DOE NETL under Award Number DE-FC26-05NT42592.

DOE DISCLAIMER

ACKNOWLEDGMENTS
This document was made possible through the contributions and efforts of numerous groups from throughout the United States and Canada. We would like to acknowledge the Plains CO_2 Reduction (PCOR) Partnership partners for their efforts in providing much of the information used for the assessments and cooperation in producing a regional portfolio for public use. We also extend our appreciation to the various federal, state, and private organizations and university groups for their cooperation in our search for data.

Several members of the PCOR Partnership research team at the EERC provided valuable input to this effort through the production of technical publications, presentations, and outreach materials. This body of work provided the foundation from which this document was created.

The following EERC staff focused on the execution of PCOR Partnership efforts through 2019. It was through their creative energy and collective efforts that the production of this document was possible:

> Heather Altepeter, Ted Aulich, Scott Ayash, Alexander Azenkeng, Nicholas Azzolina, César Barajas-Olalde, Christopher Beddoe, Nicholas Bosshart, Barry Botnen, Shaughn Burnison, Matthew Burton-Kelly, Shane Butler, Charlene Crocker, Janet Crossland, Chantsalmaa Dalkhaa, Dan Daly, Thomas Doll, Neil Dotzenrod, Janelle Ensrud, Kurt Eylands, Ian Feole, Curt Foerster, Jun Ge, Kyle Glazewski, Charles Gorecki, Carol Grabanski, John Hamling, John Harju, Steven Hawthorne, Jun He, Loreal Heebink, Janelle Hoffarth, John Hurley, Lonny Jacobson, Melanie Jensen, Tao Jiang, Lu Jin, Nicholas Kalenze, Ryan Klapperich, Robert Klenner, Patricia Kleven, Randall Knutson, Justin Kovacevich, Bethany Kurz, Marc Kurz, Kerryanne Leroux, Amanda Livers-Douglas, Kathleen McIntyre, Blaise Mibeck, David Miller, Mark Musich, David Nakles, Carolyn Nyberg, Benjamin Oster, Wesley Peck, Lawrence Pekot, Lucia Romuld, Steven Schlasner, Kari Schmidt, Steven Smith, James Sorensen, Edward Steadman, Jenny Sun, José Torres, Heidi Vettleson, Tami Votava, Neil Wildgust, William Wilson, and Agustinus Zandy.

This material is based upon work supported by the U.S. Department of Energy National Energy Technology Laboratory under Award No. DE-FC26-05NT42592.

TABLE OF CONTENTS

LIST OF FIGURES ... iii

LIST OF TABLES ... iv

EXECUTIVE SUMMARY ... v

CHAPTER 1: INTRODUCTION ... 1

CHAPTER 2: PCOR PARTNERSHIP RESEARCH PROGRAM ... 3

CHAPTER 3: STORAGE PROJECT DEVELOPMENT – BASIC CONSIDERATIONS ... 5

CHAPTER 4: ADAPTIVE MANAGEMENT APPROACH ... 7
- 4.1 AMA Application ... 8
  - 4.1.1 AMA Technical Element Application to Generic and Dedicated Storage Projects ... 9
  - 4.1.2 Dedicated Versus Associated Storage ... 11
- 4.2 State of Best Practice – AMA ... 12

CHAPTER 5: SITE CHARACTERIZATION ... 13
- 5.1 Site Screening ... 13
- 5.2 Feasibility and Design ... 15
  - 5.2.1 New Wells for Site Characterization Data Acquisition ... 16
- 5.3 Construction/Operations Phase ... 19
- 5.4 Closure/Postclosure ... 20
- 5.5 Cost Considerations ... 20

CHAPTER 6: MODELING AND SIMULATION ... 22
- 6.1 Modeling ... 22
  - 6.1.1 Data Considerations ... 22
  - 6.1.2 Model Structure ... 24
  - 6.1.3 Property Distribution ... 24
- 6.2 Numerical Simulation ... 25
  - 6.2.1 Simulation Design ... 25
  - 6.2.2 Determining the Fate of Injected CO_2 ... 26

CHAPTER 7: RISK ASSESSMENT ... 28
- 7.1 Risk Assessment Process for Storage ... 28
- 7.2 Risk Assessment for Dedicated Versus Associated Storage Sites ... 29
  - 7.2.1 Limited Site-Specific Subsurface Characterization for Dedicated Storage Sites ... 29

Continued . . .

TABLE OF CONTENTS (continued)

7.2.2 Existing Geologic Models and Predictive Simulations for Associated Storage Sites ... 30
7.2.3 Potential Leakage Pathways ... 30
7.2.4 Regulatory Paradigms ... 30
7.3 AMA for the Risk Assessment Process ... 31
7.4 Application of the Risk Assessment Process to Storage Projects ... 31

CHAPTER 8: MONITORING, VERIFICATION, AND ACCOUNTING ... 36
8.1 Development of a Monitoring Program ... 36
8.1.1 Establish Monitoring Objectives ... 36
8.1.2 Select Monitoring Techniques ... 38
8.1.3 Establish Baseline Conditions ... 39
8.1.4 Conduct Operational and Postclosure Monitoring ... 41

CHAPTER 9: INTEGRATED CASE STUDIES ... 43
9.1 Case Study 1: Dedicated CO_2 Storage ... 43
9.1.1 Site Characterization ... 43
9.1.2 Modeling and Simulation ... 44
9.1.3 Risk Assessment ... 45
9.1.4 MVA ... 46
9.2 Case Study 2: Associated CO_2 Storage ... 49
9.2.1 Site Characterization ... 49
9.2.2 Modeling and Simulation ... 49
9.2.3 Risk Assessment ... 50
9.2.4 MVA ... 50
9.3 Case Study Highlights ... 54

CHAPTER 10: CONCLUSION ... 56

REFERENCES ... 58

LIST OF FIGURES

1 Map of the PCOR Partnership region ... 2

2 PCOR Partnership AMA for assessment, development, and deployment of commercial CO_2 storage projects ... 7

3 Relative LOE typically associated with each AMA technical element during each phase of a commercial CO_2 storage project ... 8

4 Generalized approach for assembling site characterization data needed to build geologic model ... 16

5 Slabbed sandstone core from a prospective CO_2 storage formation ... 17

6 Model cross sections showing porosity and permeability for a reservoir interval and underlying and overlying seals ... 23

7 Gas (CO_2)-per-area maps developed from numerical simulation at different time steps after injection ceased at an EOR site ... 27

8 Risk management process adapted from the ISO 31000 standard ... 28

9 Best practices procedure for CO_2 storage project risk assessments ... 32

10 Illustrative example of a risk map for a dedicated saline storage project showing the ranking of individual risks and the suggested actions for the different risk ranks ... 35

11 Map of Case Study 1 project area ... 43

12 Seismic amplitude summation map for a thin, clastic reservoir used to understand heterogeneity prior to initiation of CO_2 injection ... 48

13 Time-lapse series of PNLs showing changes in fluid saturations in the reservoir interval between baseline and repeat campaigns for an injection well and a production well ... 52

14 Example 4-D difference seismic amplitude map, taken for illustrative purposes from a real CO_2 EOR project ... 53

LIST OF TABLES

1 Example Risk Probability Scores Used for Storage Projects 33

2 Example Risk Impact Criteria for Different Project Attributes 33

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

TECHNICAL ASSESSMENT OF GEOLOGIC CARBON DIOXIDE (CO_2) STORAGE: BEST PRACTICES DERIVED FROM PHASE III OF THE PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PROGRAM, 2007–2018

EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC), was formed as part of the U.S. Department of Energy (DOE) Regional Carbon Sequestration Partnerships (RCSP) Initiative in 2003. The RCSP Program supports deployment of carbon capture, utilization, and storage (CCUS) technologies—with primary focus on carbon utilization and geologic storage of carbon dioxide (CO_2) (hereafter referred to as storage)—as an essential means of reducing the carbon intensity of electricity generation and other CO_2-emitting industrial processes. The PCOR Partnership has a growing membership, which has included over 120 industry, government, and research organizations, and over a decade of experience developing, testing, and validating methods and technologies for conducting CO_2 storage projects. Nine U.S. states and four Canadian provinces comprise the PCOR Partnership region, covering an area of 1.4 million square miles in the northern Great Plains.

The PCOR Partnership has investigated storage as a means to mitigate greenhouse gas emissions, focusing on two primary approaches: dedicated storage in deep saline formations (DSFs), with the sole objective of preventing anthropogenic CO_2 entrance into the atmosphere, or associated storage that occurs as a result of subsurface CO_2 injection for other purposes, primarily during commercial CO_2 enhanced oil recovery (EOR) operations. The purpose of this publication is to summarize best practices for the assessment and management of storage, derived from PCOR Partnership research and in collaboration with member organizations.

The PCOR Partnership region has outstanding potential for widespread CCUS deployment, with established fossil fuel industries, major emission sources, and highly prospective geology for the location of storage sites. Characterization efforts have identified significant storage resource potential comprising 25 billion metric tons (or gigatonnes, Gt) in depleted oilfield reservoirs, 2–10 Gt in select oil fields that are candidates for CO_2 EOR, and 370–1200 Gt of storage in currently evaluated DSFs.

PCOR Partnership studies indicate that CO_2 EOR may result in incremental oil recovery potential of at least 280 million barrels (MMbbl), and potentially as much as 630 MMbbl, in 86 conventional oil fields within just the Williston Basin portion of the PCOR Partnership region. This potential for high-volume incremental oil production represents major economic incentive for initiating new CO_2 storage projects. Currently, CO_2 is being captured at the Dakota Gasification Company Great Plains Synfuels Plant near Beulah, North Dakota, and at the SaskPower Boundary Dam power plant near Estevan, Saskatchewan. CO_2 from both sources is transported for EOR and associated storage at the Weyburn oil field in southern Saskatchewan. The Weyburn Field has now accommodated in excess of 30 million metric tons (Mt) of associated storage and facilitated the

International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) Weyburn–Midale CO_2 Monitoring and Storage Project, a major international storage research initiative concluded in 2013. Another CO_2 EOR and associated storage project within region, the Bell Creek Field in southeastern Montana operated by Denbury Onshore LLC, has to date stored 6 Mt of CO_2. Bell Creek has provided an opportunity for the PCOR Partnership to build on the legacy of applied research at Weyburn with extensive assessment and monitoring of industrial-scale associated storage.

In comparison to CO_2 EOR, dedicated storage projects have been more limited in number and scale, typically relying on direct government funding in the absence of economic drivers for project deployment. However, both dedicated and associated storage opportunities will likely increase in response to technology, economic, and regulatory changes. To encourage dedicated storage project implementation, the PCOR Partnership is engaged in ongoing field-based research to identify and develop project opportunities. The PCOR Partnership is a key member of the technical team that conducted CO_2 injection modeling and monitoring, verification, and accounting (MVA) in support of the Aquistore Project, where over 160,000 metric tons of CO_2 from the SaskPower Boundary Dam 3 power plant (CO_2 not required by the Weyburn oil field) has been injected since 2014 into the Deadwood Formation for dedicated storage. Also in the PCOR Partnership region, the Shell Quest Project in Alberta, Canada, has resulted in dedicated storage of over 3 Mt of CO_2. Research activities, data generation, and interaction with regulatory entities at both sites have contributed to development of a procedural road map for future dedicated storage projects in Canadian portions of the PCOR Partnership region and elsewhere.

In the U.S. portion of the PCOR Partnership region, North Dakota has been granted primacy by the U.S. Environmental Protection Agency in permitting of underground injection control (UIC) Class VI wells for dedicated storage CO_2 injection, effectively streamlining and reducing uncertainty in the permitting process. This is beneficial to development and financing of both storage project types, because nearby dedicated storage capacity is often needed as a "buffer" to deal with EOR operations-driven CO_2 demand fluctuations, as in the case of Aquistore. The combination of viable CO_2 sources, a receptive regulatory and permitting environment, and ideal geologic characteristics elevate the PCOR Partnership region (both U.S. and Canadian portions) to high-priority status in terms of both dedicated and associated storage opportunities.

With favorable conditions for future potential CO_2 storage projects in the PCOR Partnership region, a remaining challenge is determining an approach to guide a storage project through all stages of development, should an economic case emerge. Through acquisition of an extensive knowledge base derived from a wide range of storage projects, the PCOR Partnership has developed a set of recommended best practices for guiding storage projects through the stages of site screening, feasibility assessment, design, construction/operation, and closure/postclosure. This knowledge has been consolidated within a framework consisting of the PCOR Partnership adaptive management approach (AMA) for the commercial development of CO_2 storage projects. At the heart of the AMA are four technical elements necessary for any successful CO_2 storage project: 1) site characterization, 2) modeling and simulation, 3) risk assessment, and 4) MVA.

Execution and integration of each of these elements through the AMA enables efficient gathering and assessment of site-specific data needed to 1) provide fundamental understanding of a potential storage complex, 2) predict and assess performance, and 3) demonstrate safe and successful operation. This information is presented primarily to provide guidance to project developers, regulators, and others interested in evaluating and developing CO_2 storage opportunities and to serve as a useful reference for CO_2 storage technical specialists.

Plains CO_2 Reduction (PCOR) Partnership

Energy & Environmental Research Center (EERC)

TECHNICAL ASSESSMENT OF GEOLOGIC CARBON DIOXIDE (CO_2) STORAGE: BEST PRACTICES DERIVED FROM PHASE III OF THE PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PROGRAM, 2007–2018

CHAPTER 1: INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC), was formed as part of the U.S. Department of Energy (DOE) Regional Carbon Sequestration Partnerships (RCSP) Initiative in 2003. The RCSP Program supports deployment of carbon capture, utilization, and storage (CCUS) technologies—with primary focus on geologic storage of carbon dioxide (CO_2) (hereafter referred to as storage)—as an essential means of reducing the carbon intensity of electricity generation and other CO_2-emitting industrial processes.

The PCOR Partnership region comprises nine U.S. states and four Canadian provinces, covering an area of 3.6 million square kilometers in the northern Great Plains (Figure 1). Established fossil fuel industries, major emission sources, and highly prospective geology for the location of storage sites in this region combine to provide ideal conditions for the widespread deployment of CCUS projects. This outstanding regional potential, in combination with over a decade of PCOR Partnership applied research designed to develop, test, and validate storage technology, has motivated over 120 organizations to join and actively engage in the partnership. This membership has been drawn from key industrial sectors with a stake in CCUS deployment as well as governmental and research partners.

The purpose of this publication is to summarize best practices for the technical assessment and management of storage, derived from PCOR Partnership research and in collaboration with member organizations. Two scenarios are considered:

- *Dedicated storage* in deep saline formations (DSFs), with the sole objective of preventing anthropogenic CO_2 entrance into the atmosphere.

- *Associated storage* that occurs as a result of subsurface CO_2 injection for other purposes, primarily during commercial CO_2 enhanced oil recovery (EOR) operations.

A geologic CO_2 storage project may be classified as dedicated storage, associated storage, or a combination of these. Operational dedicated storage projects within the PCOR Partnership region include the Quest Project in Alberta, which has resulted in the permanent storage of over 3 million metric tons (Mt) of CO_2 as of June 2018, and the Aquistore Project in Saskatchewan, at which approximately 150,000 tonnes of CO_2 has been stored. Other dedicated storage projects include the Sleipner Project in the Norwegian North Sea, which has been injecting approximately

Figure 1. Map of the PCOR Partnership region (Ayash and others, 2016).

1 Mt of CO_2 per year since 1995 into a DSF. First undertaken in Texas in the 1970s, over 100 CO_2 EOR sites are now operational in the United States (Oil and Gas Journal, 2014). Associated storage projects within the PCOR Partnership region include the Zama oil field of northwest Alberta, the Weyburn Field of Saskatchewan, and the Bell Creek Field of southeastern Montana. The technology is also being deployed in other countries, including Canada, Brazil, Mexico, and Saudi Arabia (Global CCS Institute, 2017). Although predominantly linked to CO_2 EOR, associated storage could also result from enhanced coalbed methane (ECBM) or enhanced gas recovery (EGR) operations; however, these scenarios remain unproven at a commercial scale.

The primary audience for this publication is considered to be the non-technical specialist with an interest in understanding storage – such as a project developer or regulator. However, technical specialists may also find the document useful as a reference. Many of the best practices described are applicable to storage projects beyond the PCOR Partnership region, including offshore settings.

The scope of this document does not include best practices in relation to the capture or transport aspects of CCUS projects. Similarly, utilization options for captured CO_2 other than EOR are not covered. More general information on the wider aspects of CCUS and carbon management are detailed in the latest PCOR Partnership Atlas (5th Edition) (Peck and others, 2016). Technical terms used in this document are in agreement with the definitions provided by Canadian Standard Z741 (Canadian Standards Association, 2012), except where otherwise stated.

CHAPTER 2: PCOR PARTNERSHIP RESEARCH PROGRAM

The PCOR Partnership has largely focused on characterizing the CO_2 sources and potential geologic storage targets in the region. The region is defined as including Missouri, Iowa, Nebraska, Wisconsin, Minnesota, North Dakota, South Dakota, parts of Wyoming and Montana, and the Canadian provinces of Manitoba, Saskatchewan, Alberta, and part of British Columbia.

There are numerous large, stationary CO_2 emission sources in the PCOR Partnership region. In the upper Mississippi River Valley and along the western shores of the Great Lakes, large coal-based electrical generators power the manufacturing plants and agricultural processing plants of St. Louis, Minneapolis–St. Paul, and Milwaukee. To the west, the prairies and badlands of the north-central United States and central Canada are home to coal-based power plants, natural gas-processing plants, ethanol plants, and refineries that further fuel the industrial and domestic needs of cities throughout North America. Among the largest regional CO_2 sources are coal-based power plants located in western North Dakota that emit a total of 45 Mt of CO_2 each year.

Characterization conducted under PCOR Partnership Phase I (2003–2005) confirmed that the region has substantial CO_2 storage resources. Oil fields already considered capable of storing CO_2 are present in five states and all provinces of the region. DSFs exist in basins that, in some cases, extend unbroken over thousands of square miles. PCOR Partnership evaluations found that oil fields, coal seams, and saline aquifers evaluated in the PCOR Partnership region could store at least 340 gigatonnes (Gt) of CO_2 and possibly as much as 1100 Gt. In addition, 79 years of state CO_2 emissions could be stored in North Dakota conventional oil fields during EOR activities alone. Similar source-to-oilfield–sink relationships exist in the Montana, Wyoming, South Dakota, Saskatchewan, and Alberta portions of the PCOR Partnership region.

As PCOR Partnership Phase I activities concluded, the region was deemed an ideal location for the siting of a commercial carbon-managed energy complex that integrates CO_2 capture, EOR, and dedicated storage because of the presence of substantial coal resources, oil fields, and DSFs. Many large sources in the region are proximally located to large-capacity storage formations, and in some cases, the infrastructure necessary for CO_2 storage is already largely in place.

Validation tests in PCOR Partnership Phase II (2005–2009) were selected based on their potential to become market-driven, full-scale geologic storage opportunities. The criteria used to select the validation tests included 1) the regional significance of the opportunities (i.e., number and availability of source types, number and capacity of storage formation types); 2) the diversity, capacity, and permanence of storage formations investigated; 3) the applicability of the research findings to other regions; 4) socioeconomic factors such as risk, public acceptance, and potential full-scale deployment economics; and 5) societal cobenefits.

To ensure the generation of a diverse data set during the PCOR Phase II demonstrations, conditions that were distinctly different from existing CO_2 storage test sites (such as at the Weyburn Field in Saskatchewan) were sought. Varying geologic framework (depth, structure, and stratigraphy) and CO_2 stream composition (combination of CO_2 and hydrogen sulfide [H_2S]) were pursued to provide data regarding the behavior and storage permanence of CO_2 at conditions that had not yet been evaluated (i.e., high pressure and temperature, depth) as well as the impact of high concentrations of H_2S on the integrity of a carbonate sink and well seal. When possible, oil fields or other overlying or underlying formations conducive to CO_2 storage were investigated for potential future studies of multizone injection, or stacked storage, and the fate of CO_2 storage in other rock types.

PCOR Partnership Phase III activities were focused on large-scale field testing to confirm that projects of at least 1 Mt of captured CO_2 per year can achieve safe, permanent, and economical storage. These activities included a large-scale field test at the Bell Creek oil field in southeastern Montana, a CO_2 EOR project operated by Denbury Onshore LLC, which has resulted in the storage of more than 6 Mt of CO_2. The overall mission of the Phase III program has been to 1) gather characterization data to verify the ability of the target formations to store CO_2, 2) facilitate the development of the infrastructure required to transport CO_2 from sources to injection sites, 3) facilitate sensible development of the rapidly evolving North American regulatory and permitting framework, 4) develop opportunities for PCOR Partnership partners to capture and store CO_2, 5) facilitate the establishment of a technical framework by which carbon and/or tax credits can be monetized for CO_2 stored in geologic formations, 6) continue collaboration with other RCSPs, and 7) provide outreach and education for CCUS stakeholders and the general public.

In summary, PCOR Partnership efforts across three phases of investigation have shown the region has suitable geology, an abundance of fossil fuel resources, and an industrial and energy development base that combine to provide an ideal opportunity to deploy CCUS as a carbon management strategy. Carefully selected and monitored storage sites present very low and manageable levels of risk to human health, the environment, and other natural resources. The predominant geologic storage formations found in the region are present elsewhere in the United States and western Canada; therefore, the results of the demonstrations performed at these sites would apply to many other locations outside of the PCOR Partnership region.

Also of importance to the selection of commercial sites are the safety and attitude of the population living near the storage sites. Because much of the area is an energy-producing locale, the local communities are favorably inclined to new drilling activities. Best practice guidance on public outreach is beyond the scope of this document, but available in a U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) publication (2017a).

CHAPTER 3: STORAGE PROJECT DEVELOPMENT – BASIC CONSIDERATIONS

When planning any type of storage project, the project should be adequately defined prior to initiation. Examples of key project elements that should be defined prior to project initiation (for all CO_2 storage scenarios) include the following:

- Overall goal – What is the desired project outcome?

- Scope – What steps/procedures are needed to achieve key project objectives?

- CO_2 source
  - How much CO_2 is being produced and captured?
  - What is the CO_2 stream composition?
  - Will CO_2 amount and composition be relatively consistent throughout the anticipated project duration or subject to significant fluctuation?

- Storage target
  - What storage capacity is required?
  - Is a combination of dedicated or associated storage a viable option?
  - If associated storage (i.e., CO_2 EOR) is an option, can the project accommodate fluctuating demand from the oil company partner(s)? Dealing with EOR-driven demand fluctuations can often require access to separate dedicated storage capacity to serve as a “buffer” for injection of CO_2 delivered in excess of unplanned reduced EOR requirements.

- Finances
  - What level of financial commitment is available?
  - Who are the financial contributors to the project?
  - Is the project trying to gain financial credit for stored CO_2, and if so, what role will this credit play in overall project viability?
  - How stable are short- and long-term project financial arrangements?

- Time line
  - Are there key regulatory requirement deadlines that need to be met?
  - If targeting associated storage, when does the oil producer partner expect CO_2 to be available for delivery?

After settling the storage project definition, an approach is needed to guide subsequent activities required for proper planning, execution, and closure of the project. Such an approach has been developed through PCOR Partnership research conducted for both dedicated and associated storage scenarios, referred to as an adaptive management approach (AMA). This approach and the four technical elements upon which it relies are discussed in the following chapters of this document. These technical elements include 1) site characterization; 2) modeling and simulation; 3) risk assessment; and 4) monitoring, verification, and accounting (MVA). General technical discussion is included as well as important technical facets that represent best practices for storage project assessment. While the best practices described herein have been drawn from lessons learned in the PCOR Partnership region, many of the recommendations are applicable to other storage environments and scenarios, including offshore projects.

Individual PCOR Partnership best practices manuals (BPMs) have been published for the AMA and each of the four primary storage project technical elements listed in the previous paragraph. These individual PCOR Partnership BPMs contain more in-depth discussion for each of these topics: 1) AMA (Ayash and others, 2016), 2) site characterization (Glazewski and others, 2017), 3) modeling and simulation (Bosshart and others, 2018), 4) risk assessment (Azzolina and others, 2017), and 5) MVA (Glazewski and others, 2018).

The intent for this document is to supplement, rather than replace, these BPMs in providing an introduction to, and condensed summary of, all five topics. This information is presented primarily to provide guidance to project developers, regulators, and others interested in evaluating and developing CO_2 storage opportunities and to serve as a useful reference for CO_2 storage technical specialists. Through the following chapters, a process is presented illustrating iterative integration of these technical elements across the life cycle phases of a CO_2 storage project (site screening, feasibility, design, construction/operation, and closure/postclosure) to yield a fit-for-purpose strategy for commercial deployment. Two case studies are also included to demonstrate integration of these technical elements in the execution of commercial CO_2 storage projects.

CHAPTER 4: ADAPTIVE MANAGEMENT APPROACH

The AMA is derived from PCOR Partnership collective experience and lessons learned and represents a best practice for advancing the commercialization of CO_2 storage projects. At the heart of the AMA are four technical elements necessary for any successful CO_2 storage project: 1) site characterization, 2) modeling and simulation, 3) risk assessment, and 4) MVA. Each technical element plays a role in gathering and assessing site-specific data that provide or improve fundamental understanding of the storage complex. While each of the four technical elements independently provides useful data, integrating them through the AMA yields a streamlined, fit-for-purpose strategy for commercial project assessment, development, and deployment. Key to this integration are feedback loops that allow outputs from each element to serve as inputs to other elements. Each AMA iteration generates improved technical understanding of the storage complex, resulting in more targeted and efficient applications of the technical elements in each subsequent iteration. Figure 2 summarizes the PCOR Partnership-formalized AMA for commercial deployment of CO_2 storage projects.

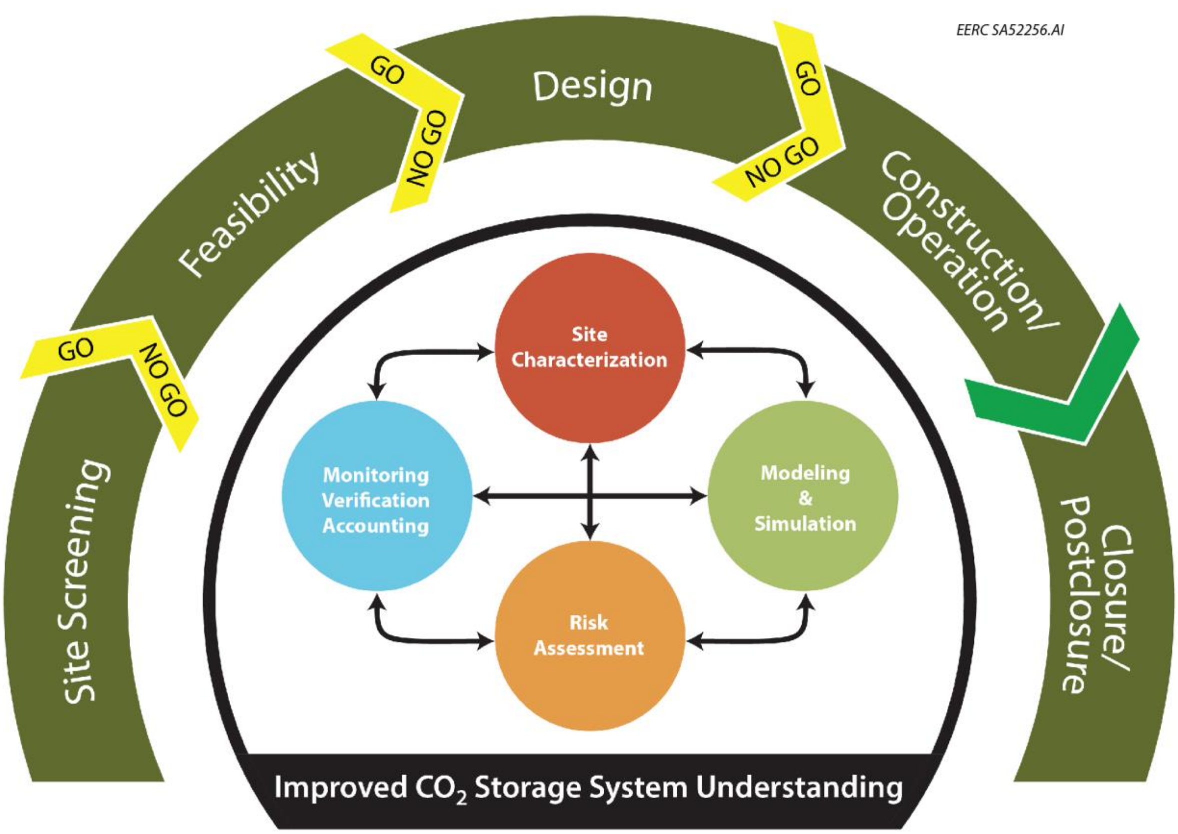

Figure 2. PCOR Partnership AMA for assessment, development, and deployment of commercial CO_2 storage projects (modified from Gorecki and others, 2012).

A CO_2 storage project will advance through a series of project phases—site screening, feasibility, design, construction/operation, and closure/postclosure—with the AMA applied during each phase. As part of each phase, specific technical, economic, and regulatory questions need to be answered prior to advancing to the next project phase. Following each of the preoperational development phases of the project (site screening, feasibility, and design) are go/no-go decision points that allow the project developer to determine if advancement to the next phase is warranted. The AMA provides the necessary framework to gather the data needed to answer the questions at each project phase and facilitate commercial deployment; however, the exact boundary or scope of a particular life cycle phase may vary from project to project, with the phases potentially overlapping one another based on the perspective and needs of the individual project operators.

Currently, CO_2 storage is focused on the two primary approaches of dedicated storage in DSFs and associated storage that occurs primarily during commercial CO_2 EOR operations. Although key differences exist between these approaches, the PCOR Partnership AMA can be used to successfully advance commercial projects of either type.

4.1 AMA Application

The AMA typically begins with some form of site characterization, proceeding in an iterative fashion through modeling and simulation, risk assessment, and MVA. An important AMA attribute is that it helps ensure that resources (whether personnel or financial) are focused on addressing key site-specific questions or issues. The AMA was developed with the recognition that 1) not all four technical elements may be required at every project phase and 2) the level of detail to which an element is performed during each phase can vary. Figure 3 provides a generalized depiction of the estimated relative level of effort (LOE) that is typically allocated to each technical element

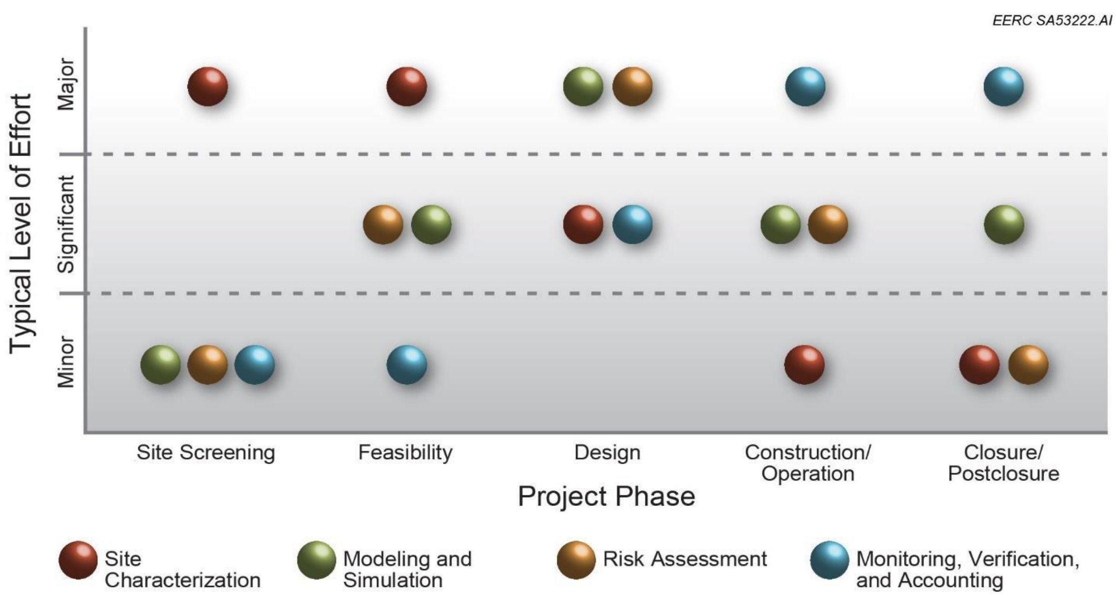

Figure 3. Relative LOE typically associated with each AMA technical element during each phase of a commercial CO_2 storage project.

during each project phase. As presented, site characterization represents a major LOE during the site-screening and feasibility phases of a project, subsequently decreasing to a minor LOE during the construction/operation and closure/postclosure project phases, where characterization activities are largely limited to targeted investigations to better understand any unacceptable risks or monitoring anomalies that might be observed. Risk assessment LOE increases steadily during site screening through design, then decreases. MVA LOE steadily increases to reach its peak level during construction/operation and closure/postclosure. Modeling and simulation LOE reaches its peak during the design phase and subsequently decreases throughout construction/operation and closure/postclosure.

Consistent with its fit-for-purpose philosophy, the AMA is driven by the nature of the questions addressed at each project phase and the level of information needed by project developers to make go/no-go decisions at critical points in the project. Notably, technical element application during each project phase is also influenced by the nature (dedicated, associated, or combined) of the storage scenario. The next two subsections summarize 1) key aspects of AMA application to generic storage projects, with a focus on dedicated storage projects, and 2) key considerations associated with AMA application specifically to associated storage projects.

4.1.1 AMA Technical Element Application to Generic and Dedicated Storage Projects

Site Characterization

Site characterization is defined here as the acquisition and analysis of data to develop an understanding of critical properties and characteristics of storage project-relevant surface and subsurface environments. Depending on the project phase, several different types of data may be collected including petrophysical, mineralogical, geomechanical, hydrogeological, geophysical and geochemical. As shown in Figure 3, data acquisition occurs throughout the entire project, although the intensity of the effort and the characterization techniques employed vary with project phase. For example, reliance on readily available information in published literature and from state regulatory agencies will dominate the site-screening and early-stage feasibility phases of most projects; however, field data collection activities will tend to dominate with project progression. More targeted field efforts conducted during operations will primarily focus on addressing unacceptable risks and/or monitoring performance and/or environmental anomalies. Site characterization is not typically conducted during the closure/postclosure phase of the project but may be required to investigate any unacceptable risks and to define mitigation actions, should they be required.

Modeling and Simulation

Static geocellular models that represent the subsurface as well as dynamic simulations to predict the effects of injecting and storing CO_2 are important for designing a CO_2 storage system, assessing project risks, and designing and interpreting results of a MVA program. A primary challenge associated with this element is balancing the complexity and detail of a geocellular model with the computing power and time needed to generate predictions based on that model. Modeling efforts typically begin early in the development of a project and continue throughout the operation of the site, with the precision and complexity increasing over time. For example, preliminary static models with little or no dynamic simulation are often sufficient to meet the needs of the screening phase of the project. However, as the project moves through feasibility toward a final design, running CO_2 injection simulations becomes critical in defining the area of review (AOR) as well as in developing a better understanding of potential risks related to CO_2 migration and subsurface pressure effects. If field production or injection data exist prior to the start of CO_2 injection, as is often the case for CO_2 EOR or depleted hydrocarbon field sites, then simulation models can be history-matched based on legacy operational data to improve predictions of reservoir performance. Because of the inherent uncertainties in data used to create static and dynamic models, uncertainty scenarios created and run, the models and results should be frequently assessed and, if necessary, revised based on history matching of model outputs with additional operating and MVA data gathered during the project operation phase. Moving into the closure/postclosure phase, the resulting calibrated models should be sufficient to continue supporting interpretation of MVA data.

Risk Assessment

Project risk identification and assessment (qualitatively or quantitatively) is initiated early and refined as more characterization, operational, and monitoring data become available. While a high-level risk assessment may be performed at the site-screening phase using generic lists of risks associated with the geologic storage of CO_2, initial risk assessments are usually conducted during the feasibility phase of the project to create a site-specific risk register that can be updated during subsequent phases based on refined predictions of storage system performance. Risk assessments conducted at the design phase are especially important since it is still possible to make changes in the storage system configuration and planned operations to eliminate potentially unacceptable risks. Risk assessment will continue through the operation and closure/postclosure phases based on data collected through the MVA program. Continuation of risk assessment efforts in latter project phases is important to demonstrate to the public, federal and state regulators, and other stakeholders that the risk profile of the subsurface storage of CO_2 is being continuously monitored and remains at an acceptable level.

Monitoring, Verification, and Accounting

Monitoring is defined here as the measurement and surveillance activities necessary to provide an assurance of the integrity of CO_2 storage. Verification is defined here as the comparison of the predicted and measured safe performance at a storage project. The “accounting” component of an MVA program entails methods for quantifying the amount of stored CO_2, typically for the purpose of deriving emission reduction credits (e.g., American Carbon Registry, 2015). Accounting procedures are not discussed in this document. The focus is instead placed on monitoring activities that are designed to provide the data required for storage verification by regulatory processes.

Monitoring data have multiple uses, but their primary purpose is to enable verification that injected CO_2 and other formation fluids are contained within the target storage complex.[1] These monitoring data also provide information needed to assess potential negative impacts to the

[1] Storage complex refers to the storage unit(s) and seal formation(s) extending laterally to the defined limits of the storage operation.

subsurface environment and to support other technical elements of the AMA such as the continued refinement of models and simulations and site-specific risk assessment.

Other than baseline monitoring activities performed during the feasibility, design, or construction phases, monitoring activities are primarily implemented during the operational phase and continue through closure/postclosure. A wide variety of surface, near-surface, and deep subsurface monitoring techniques are employed for MVA purposes. Many of these techniques (including geophysical logging and seismic surveys) may be the same as those used during site characterization activities. Site characterization data provide new information and/or verify existing data related to the static geologic storage system prior to CO_2 injection. In contrast, MVA data track the dynamic response of the system during active CO_2 injection and to document CO_2 containment in the storage complex during operation and through closure/postclosure.

Current research and development (R&D) efforts for storage are increasingly focused on the integration of data from appropriate suites of technologies that can improve the resolution of monitoring programs. A related objective is to speed up the execution and interpretation of monitoring with the ultimate aim of providing real-time results that would provide maximum benefit to operations. Such technology developments may feed into future best practices for storage.

4.1.2 Dedicated Versus Associated Storage

Consistent with AMA philosophy, the fit-for-purpose mix and progression of technical elements employed will be different for dedicated and associated storage projects. For example, since the latter will typically involve an oil field that has been active for some time, there will likely be fewer requirements for acquisition of data through new fieldwork activities. At the same time, the documentation of stored CO_2 may be more complex because of the number of injection wells and the operation of a CO_2-recycling system. A brief discussion of key differences in technical element application to dedicated versus associated storage projects is provided as follows.

As with dedicated storage, CO_2 EOR projects will rely heavily on readily available data from the literature and other public sources to inform site characterization during early phases of the project. Moreover, since oil fields (especially those already undergoing EOR) are usually well characterized, it is also likely that there will be significant nonpublic operator-generated data available for assessment of associated storage potential. As a result, limited—if any—site characterization field activities will likely be required during initial project phases. Needed field activities would likely be focused on data gaps regarding storage aspects of the site as opposed to incremental oil recovery, although data collected would likely provide a dual benefit.

Because of their focus on predicting subsurface migration of injected CO_2, modeling and simulation efforts required for dedicated and associated storage sites are often similar. Additional associated storage-specific objectives may be focused on improving understanding of the impact of CO_2 EOR operations on estimated recoverable oil and effects of oil production on CO_2 plume evolution.

Both dedicated and associated storage will result in long-term subsurface containment of injected CO_2; however, risk profiles for associated storage projects may differ substantially from dedicated storage. Given that reservoirs targeted for CO_2 EOR will likely have considerable existing subsurface characterization and operational data, it is likely that risks associated with reservoir performance and geologic uncertainty are well-understood and at acceptable levels. Conversely, the activities that garnered the existing data (e.g., installation of numerous CO_2 injection and oil production wells) may increase the likelihood of environmental risks associated with out-of-zone vertical migration of CO_2 into overlying domains of concern including underground sources of drinking water (USDW), surface waters, and the atmosphere, requiring implementation of a comprehensive site risk assessment and extensive MVA programs.

As with dedicated storage, MVA program goals for associated storage projects will be focused on tracking CO_2 subsurface migration and documenting CO_2 containment in the storage complex. However, major differences in the extent and duration of MVA requirements may result from risk profile differences and differences in project regulatory environments. For example, it may not be necessary to monitor CO_2 EOR projects in accordance with recently promulgated U.S. Environmental Protection Agency (EPA) requirements for CCUS sites (i.e., Subpart RR reporting requirements [U.S. Environmental Protection Agency, 2010a]) or to extend monitoring beyond the period of CO_2 injection, as monitoring may be terminated at the time of EOR operations cessation. These differences will be largely site-specific in nature and driven by applicable regulatory requirements as well as operating and management decisions made by the site operator.

4.2 State of Best Practice – AMA

While an AMA framework for both dedicated and associated projects has been developed, practical AMA applications to date have been limited to the feasibility and construction/operation phases of commercial CO_2 storage projects. This limitation is due to the relatively short duration of the RCSP Initiative and limited deployment of dedicated CO_2 storage projects in the United States. Nevertheless, PCOR Partnership efforts have demonstrated fit-for-purpose applications of the AMA as well as the value of the feedback loops, which permit data to move between technical elements to inform and improve their execution over time. This temporal aspect of the AMA is important because of the complexity of commercial CO_2 storage projects and the nature and extent of information that must be gathered during the preoperational development phases. Based on these documented applications, the AMA is capable of incorporating and utilizing the information required to commercialize CO_2 storage sites. The AMA as presented here represents a snapshot in time and will undoubtedly be modified and adjusted as it is applied and evaluated at future CO_2 storage projects. For example, as certain MVA technologies improve and provide more real-time data, the feedback loops of the AMA may be streamlined to allow more rapid updating of other technical elements. Continuous AMA improvement extension to later project phases will help ensure safe and effective development of commercial CO_2 storage projects.

CHAPTER 5: SITE CHARACTERIZATION

Site characterization activities are largely project- and site-specific because of unique geologic settings, risk profiles, and uncertainty at each locale. As one of the four AMA core technical elements, site characterization comprises data collection, analysis, and interpretation. Information gained improves understanding of subsurface and surface environments and factors that may affect a storage project. Site characterization activities directly aid the other AMA technical elements by generating 1) data and information for use as inputs to geologic models/simulations, 2) information useful for discerning risk profile and devising risk mitigation strategies, and 3) data for establishing MVA baselines. Because the need for and objectives of site characterization activities necessarily evolve over time, the following site characterization discussion is framed in the context of project progression through the life cycle phases of site screening, feasibility and design, construction/operation, and closure/postclosure.

5.1 Site Screening

The goal of site screening may be to identify one or more candidate storage sites within the geographic area of interest or to identify and prioritize formations for further evaluation. Basic evaluation criteria should be established to enable ranking candidate storage sites or formations. Criteria unique to each potential storage project can be generated or criteria can be selected from existing publications that describe generic screening criteria (Det Norske Veritas, 2013; IEA Greenhouse Gas R&D Programme, 2009). Depending on project goals, objectives, and assets, acceptable storage targets may vary significantly in the same area because of subsurface heterogeneity and surface proximity to cities, agricultural operations, or natural resources. For example, project financial considerations could limit the potential length of a CO_2 pipeline or a utility may be interested in project opportunities for associated storage, resulting in very different project dynamics. For these reasons, a thorough project definition and establishment of site-screening evaluation criteria are imperative to ensuring a quality site-screening process and dictating the site characterization data that need to be gathered.

Generally, a candidate site will contain an injection target formation at a depth usually exceeding 800 meters (2625 feet), the depth at which pressure and temperature conditions are effective in keeping injected CO_2 in the supercritical state. In the United States, the target formation must also contain brine with a salinity greater than 10,000 mg/L total dissolved solids (TDS), which is a key metric used to define USDWs in the U.S. Code of Federal Regulations (CFR) Underground Injection Control (UIC) Program (40 CFR 144.3, 1983). Aside from the depth and salinity constraints, the target formation must also offer sufficient storage capacity, injectivity, and the geologic structure necessary for safe, long-term containment of injected CO_2. A low-permeability sealing formation (often shale) overlying the porous zone, with relative absence of major faults, fractures, or other features that could compromise containment, is needed to limit vertical migration of injected CO_2 and protect overlying USDWs. Additionally, beyond subsurface features enabling vertical migration, existing well penetrations are potential leakage pathways for CO_2. Ideally, a good storage site scenario would contain a relatively low number of existing well penetrations and/or have reliable records regarding wellbore integrity.

Investigations of these considerations require data compilation and interpretation. Data sources will vary by location; however, since a significant portion of site screening focuses on initial assessment of subsurface geology, the initial data search will often lead to state regulatory entities, universities, and public consortia. Examples of existing data sources include:

- Relevant publications and previous interpretations of the target stratigraphic intervals within the area of interest (including theses, dissertations, and peer-reviewed journals).

- Previously approved permit applications (federal or state).

- Well records, including drilling and completion procedures, well logs, pressure tests, and injection and production characteristics, and descriptions and analyses of core, drill cuttings, and fluid samples.

- Seismic surveys and interpretations.

Additionally, private databases sometimes allow purchase of non-publicly available data.

After interpretation of geologic data, screening is conducted based on storage potential in terms of resource (capacity), injectivity, and containment; these items are elaborated upon in Section 5.2 below in the context of model construction and numerical simulation. High-level storage resource potential estimates may be achieved in implementing the volumetric approach discussed in a DOE NETL publication (2012). This approach estimates CO_2 storage potential (M_{CO2}) as the product of the area being assessed (A), thickness of the target formation (h), porosity of the target formation (ϕ), density of CO_2 evaluated at pressure and temperature conditions anticipated within the target formation, and a CO_2 storage efficiency factor that reflects the fraction of the total pore volume that will be filled by CO_2 (E) (Eq. 1). Inputs and assumptions for this approach may be tailored depending on the amount of available data, such as net-to-gross area, net-to-gross thickness, effective-to-total porosity, and lithology, which may impact storage efficiency (Peck and others, 2014). Storage potential estimates achieved through this approach may enable a first pass at site screening and stacked storage potential if multiple storage formations are present.

$$M_{CO2} = A \times h \times \varphi \times \rho_{CO2} \times E \qquad \text{[Eq. 1]}$$

Sufficient information may also be available to inform preliminary risk assessment. Overall, an optimal site will have low or acceptable risks—in accordance with project criteria and goals—related to geologic suitability of the proposed project (including project type and scale), sensitive environmental receptors (including groundwater resources and ecosystems), and other subsurface resources (including oil and gas reserves). Additionally, land use and ownership can pose risks to a storage project. Potential AORs will need to be agreed on for regulatory purposes prior to project operation, and site-screening studies may identify potential needs for pore space leasing, access agreements for baseline and monitoring data acquisition, and other potentially sensitive considerations. Thus potential permitting challenges may be identified through conducting an initial review of private, federal, and tribal lands; wetlands and protected wildlife habitats; important historic grounds (archaeological, religious, or interment sites); nearby urban populations; and other surface sensitivities. After accounting for these considerations, candidate storage sites selected for further analysis will proceed to the feasibility study project phase. In the event that no candidate sites are identified during site screening, a no-go decision by the project operator would be warranted.

5.2 Feasibility and Design

The feasibility and design phases of a project establish the viability of one or more selected candidate project sites at a confidence level sufficient to support decisions on whether and how to proceed in the construction and operation of a future project. A conceptual design of the storage system will be developed, including transportation of captured CO_2, installation of any necessary surface facilities for CO_2 handling and processing, CO_2 injection, and a surface- and subsurface-monitoring program.

Assessment of storage site viability in the feasibility phase is supported by acquiring data needed to build a geologic model that accurately characterizes and represents the site geology. The geologic model is then used to conduct predictive CO_2 injection simulations and support risk assessments and corresponding mitigation plans as well as provide an initial estimation of the project AOR, which is a requirement for EPA UIC Class VI (dedicated CO_2 injection well) permitting (U.S. Environmental Protection Agency, 2010b). The AOR establishes the lateral extent of CO_2 plume migration and subsurface pressure elevation impacts expected from CO_2 injection and storage. The AOR delineates storage system boundaries that must be managed and monitored during CO_2 injection, with the objective of ensuring against occurrence of adverse effects. To comply with EPA requirements, the AOR is usually determined using computational models to ensure that it includes the full extent of the anticipated plume migration and significant pressure propagation as defined by applicable regulations encompassing all surface and subsurface areas.

Along with AOR estimates, collection of modeling and simulation outputs will provide an optimal understanding of three essential elements required for storage:

- CO_2 storage capacity: The ability of the target injection formation to receive the amount of CO_2 required for project success.

- CO_2 injectivity: The ability of the target injection formation to receive CO_2 at the project-required rate.

- CO_2 containment: The effectiveness of sealing unit(s) effective in limiting vertical migration of injected CO_2 from the storage reservoir or complex. Lateral migration may also need to be considered.

The quality of predictive model outputs depends on the accuracy of the base geologic model, which is directly related to the quality of the site characterization data used to build it. Data should be reviewed for relevance and quality. Sound workflow processes should be followed for interpreting and/or processing data for use as inputs into model building as described in Chapter 6: Modeling and Simulation. Through this process, persisting data gaps may be identified. If important information is lacking, further site characterization data acquisition may be appropriate, which may entail purchasing and processing/interpreting additional existing data and/or acquiring new data via field and laboratory activities.

Figure 4 summarizes, at a high level, a protocol for acquiring the site characterization data needed for building a representative geologic model, conducting an initial risk assessment, and establishing MVA plan elements. Acquisition of new data may be required because of inadequate depth, placement, and/or concentration of existing wells; inadequate suitability and/or number of existing well logs and/or seismic surveys; and/or insufficient data contained in existing well files.

If new data are needed, extensive planning should be done to understand relevant regulatory and permit requirements. Other considerations include community and regional public outreach to ensure adequate awareness of data collection activities and any land use impacts. Perhaps the most important method of generating new site-specific characterization data is through the drilling of new wells.

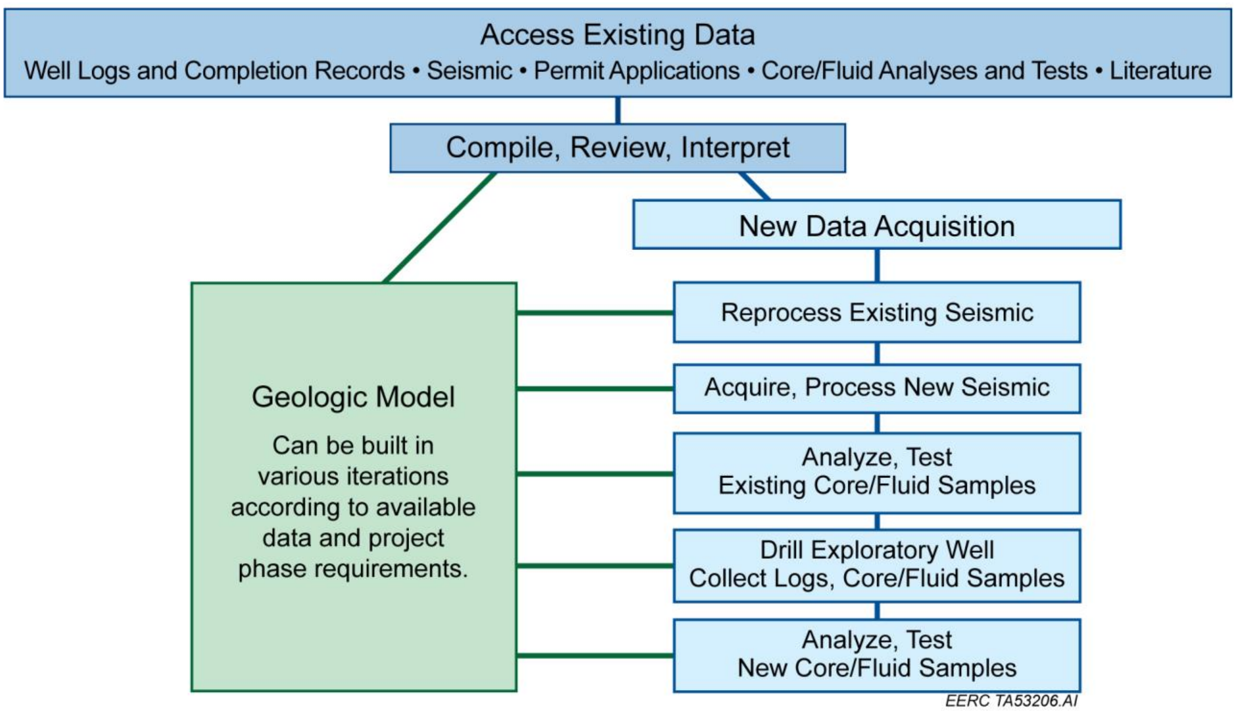

Figure 4. Generalized approach for assembling site characterization data needed to build geologic model.

5.2.1 New Wells for Site Characterization Data Acquisition

Wells provide the only means to physically sample and test (in situ) reservoir and seal formations. If insufficient data are available to equip project decision makers with an adequate level of certainty regarding suitability of a candidate storage site, drilling one or more exploration wells may be required. Exploration wells (also referred to as stratigraphic test wells) typically represent a smaller investment than injection or monitoring wells (commonly referred to as infrastructure wells). Exploratory wells may be plugged and abandoned after data acquisition or, alternatively (and more expensively), completed in accordance with more rigorous standards as infrastructure wells and maintained for potential later injection or monitoring purposes. It should be noted that assessment of associated storage will often not require drilling new exploration wells because of the presence of numerous existing wells and extensive available site characterization data acquired during hydrocarbon exploration and production operations.

In addition to precisely targeted geologic data acquired during well-logging activities, exploration wells enable acquisition of core, drill cuttings, and fluid samples. Figure 5 is a photo of slabbed core samples cut from a sandstone in investigation of storage feasibility. These samples

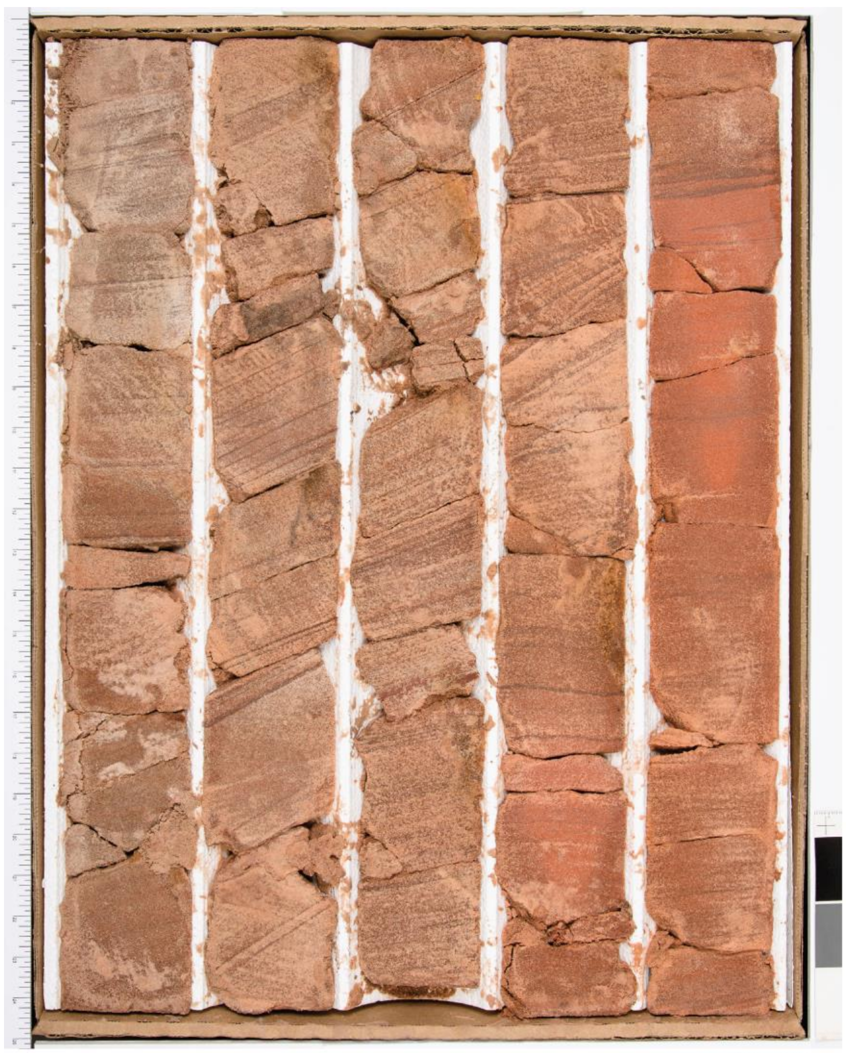

Figure 5. Slabbed sandstone core from a prospective CO_2 storage formation. Average porosity for the interval shown is approximately 30% and average permeability exceeds 1 darcy, indicative of an excellent target formation for storage.

are often needed for use in laboratory analytical and experimental activities to improve understanding of the storage reservoir and seal properties and potential geochemical interactions between these rocks, the in situ fluids, and CO_2 that could impact storage complex capacity, injectivity, and containment capability.

In deciding what type of well to drill and when, the relatively lower cost of single-purpose exploration wells must be balanced against the higher cost of a dual-purpose (exploration and injection or monitoring) infrastructure well. In addition to cost, financial risk must also be considered. Drilling an infrastructure well early in a project may involve significant risk due to the uncertainty regarding storage potential (and by extension, project site viability) and optimal well location. Factors that can impact well-drilling decisions include 1) sparseness or lack of existing wells within or near the storage reservoir and/or AOR, 2) significant uncertainty—based on the totality of existing site characterization data—regarding geologic sequence or structure within and near the storage reservoir and/or AOR, and 3) identified need for an infrastructure well.

Because of the typical depth requirement (for storage) of 800 meters or greater, wells represent one of the largest expenditures during the feasibility, design, and construction of a storage site. Exploration wells will typically cost on the order of US$1 million or more, and infrastructure wells may cost several million U.S. dollars. As a result of this up-front capital cost, decisions regarding whether, when, where, and what type of well to drill are typically only made after careful evaluation of all existing and relevant site characterization data. To ensure maximum return on any well-drilling investment, careful planning and management of drilling operations are required to gain the maximum amount of characterization data within budget constraints. Well placement can be dependent on practical issues (e.g., rig access), geologic structure or reservoir properties, outputs from injection scenario predictive modeling exercises, or a combination of these. Interpretation of seismic survey data, where available, can significantly aid well placement decisions.

Today, most management and technical aspects of drilling programs are covered by standard practices largely derived from the oil and gas industry and are beyond the focus of this discussion. However, some activities of particular importance to CO_2 storage site characterization are discussed below and should be considered for collecting geologic data when drilling a new well:

- Techniques that can improve quantification of fracture initiation pressure (i.e., maximum permitted injection pressure) could allow for greater operational flexibility in injection operations.

- Core and fluid samples are needed for conducting laboratory tests of reservoir and seal properties (e.g., porosity, permeability, relative permeability, mineralogy, and mechanical properties) or rock–fluid chemical interactions.

- Core sample acquisition is usually a significant expense within the drilling program and requires careful targeting to ensure critical sections are sampled (for example, the seal–reservoir interface) without excessive cost. Offset wells and measurement-while-drilling (MWD) technology can be used to help pick core points or intermediate logging runs may be used to support coring decisions.

- Sidewall core samples can be obtained as a cost-effective alternative to full-diameter core samples (e.g., where coring has missed important sections). However, the small sample sizes, and potential sample damage, restrict the types of laboratory testing that can be undertaken.

Wells also provide an important opportunity to test hydraulic properties of various formations and/or formation intervals via drillstem tests (DSTs) or injection tests. Tests are typically undertaken prior to well completion in which sections of the well are isolated for injection of fluids (usually brine or CO_2) into near-wellbore environments of specific reservoirs. Key objectives are to assess 1) injectivity (i.e., the ease with which fluids may be injected within the formation of interest) and 2) CO_2 behavior and interaction with formation fluids and rocks.

It should be noted that for injection tests in DSF infrastructure wells where brine is used, fluid chemistry should align as closely as possible with native formation brine and the use of freshwater should be avoided to reduce the risk of damage to the well through salt precipitation or swelling clays. An alternative approach which negates this risk involves injecting CO_2 or pumping, collection, and reinjection of native formation brine.

Following the collection of data needed to discern the feasibility of a storage site(s), the preliminary economics of the project will be estimated, along with an assessment of project-specific risks, which include both technical and nontechnical risks to the project developer as well as the public at large and other stakeholders. This type of cost–benefit information will likely be required to move forward with project-funding decisions of the construction and operation project phases.

5.3 Construction/Operations Phase

Upon completion of the site-screening, feasibility, and design project phases, a final decision will be made to proceed to storage project construction, subject to regulatory approval. By this stage, site characterization data will have supported modeling, simulation, and risk assessment efforts, with sufficient data upon which to base key project management decisions. Such decisions may include the drilling and completion of injection and monitoring wells, if not previously completed during the design phase, and the installation of other surface infrastructure to capture, compress, and transport CO_2.

Following site construction, operations will be focused on safe injection of the CO_2 into the storage reservoir(s) and monitoring the storage complex and extended surface and subsurface environments within the AOR. The purpose of monitoring is to document system performance and demonstrate the absence of unacceptable impacts to environmental or other receptors. Important criteria for operation monitoring are determining 1) if injected CO_2 is securely contained within the storage complex and behaving in conformance with model predictions, 2) if there are unexpected operational issues observed (e.g., unusual pressure buildup), and 3) if there has been a change in the project risk profile based on field observations and collected monitoring data.

The scope of site characterization activities during the construction and operation project phases (and on into the closure/postclosure phase) will tend to be progressively reduced in intensity or integrated into the other technical elements of MVA. However, data generated in the operational phase (i.e., injection rate and pressure) may be used in 1) history-matching numerical simulation models to increase the accuracy of predictive estimates and 2) updating risk assessments during the construction, operation, and closure/postclosure phases of a project. Similarly, any unexpected behavior of well operation or anomalies detected by the MVA program may require additional site characterization work. This may include more frequent data collection, with the goal of determining if—and what type of—mitigation strategies are required to address unexpected changes in CO_2 plume or pressure migration. Examples include specialized surface or subsurface technologies such as three-dimensional (3-D) seismic surveys (and time-lapse [4-D] seismic surveys), acquisition of well logs sensitive to changing fluid saturations (i.e., pulsed-neutron logs [PNLs]), related soil or groundwater sampling, and others.

5.4 Closure/Postclosure

Closure/postclosure is the last phase of a CO_2 storage project and driven by regulatory requirements and long-term liability for injected CO_2. Closure involves cessation of CO_2 injection operations and decommissioning of the storage facility, including plugging of wells and removal of surface operating facilities and infrastructure. Demonstration of effective CO_2 containment within the storage complex will be required during closure. Postclosure is a period of time following closure, with the duration set by the regulatory agency with jurisdiction over the project. In the United States, current EPA regulations have established a postclosure monitoring period of 50 years following cessation of injection; however, the final rule provides some flexibility regarding duration of this period by allowing the EPA Director to decrease or increase it based on site-specific data (U.S. Environmental Protection Agency, 2010b). Alternatively, North Dakota—the only state in the United States that has received primacy for geologic storage of CO_2 through the end of 2019—requires a postclosure period of 10 years before the state will assume liability for stored CO_2 in accordance with North Dakota Century Code §38-22-17. During postclosure, documentation will be required that stored CO_2 is securely contained in the storage complex and that there is no discernible leakage or evidence of environmental impacts from CO_2 or other formation fluids.

Similar to the construction and operation project phases, closure/postclosure site characterization activities are typically limited to special circumstances. In the event that MVA activities and numerical simulations indicate that the reservoir and contained fluids are performing as expected, no additional site characterization activities will be needed. However, if unexpected and/or unexplainable MVA data are acquired, a decision may be made (or dictated by regulatory authorities) to collect additional site characterization data for analysis.

5.5 Cost Considerations

An important consideration that deserves attention is the cost of AMA technical activities associated with implementing the various project phases. As would be expected, the total cost of each project phase will be site-specific and can be expected to vary considerably because of many factors, including scale, scope (i.e., type and level of technical activities performed), regulatory requirements, and project type (i.e., dedicated versus associated storage). For example, the scale of a project can affect the level of initial site characterization activities performed, the type and extent of required infrastructure, and the overall operating costs of the project. Additional variables to consider when estimating cost for each phase include:

- The desired level of certainty required to move from one phase of the project to the next (e.g., Will it be necessary to drill additional characterization wells or collect more seismic data?).

- The existing knowledge base for all aspects of the prospective project (e.g., Have site characterization activities been successfully completed? Have the requirements of applicable federal, state, and local regulations been defined?).

CHAPTER 6: MODELING AND SIMULATION

Modeling is defined here as the collation of subsurface data into a 3-D representation of the subsurface geology and hydrogeology of a CO_2 storage site and surrounding area. Simulation refers to the process of using specialized software to create quantitative predictions of the dynamic effects of CO_2 injection, including migration of CO_2 and other formation fluids; pressure and temperature behavior; geochemical and geomechanical effects; and the long-term fate of injected CO_2 within the modeled volume. Modeling and simulation can be undertaken at a variety of scales (from regional to site-specific) and levels of complexity and should be developed according to the fit-for-purpose philosophy that is central to the AMA. Results of modeling and simulation efforts are used to improve storage capacity estimates, determine AOR for regulatory compliance, and reduce uncertainty about long-term containment of injected CO_2.

This chapter describes best practices associated with application of modeling and simulation for dedicated storage in DSFs and associated storage. General workflows for geologic modeling and simulation are widely understood among professionals, especially for oil and gas exploration and extraction. Highlighted here are practices specific to modeling and simulation of CO_2 injection into the subsurface, particularly regarding AOR definition and trapping mechanisms that restrict or prevent long-distance migration of injected CO_2 after site closure.

6.1 Modeling

A typical geologic (or static) model being constructed to support simulation of injection will represent the storage reservoir formation(s) and confining zones (seals), together with structural features such as faults, fractures, and folds (Figure 6). It should be noted that risk assessment considerations may require modeling effort focused on strata above and/or beneath the storage complex. The basis for model construction, invariably in digital form, is a combination of measured subsurface characteristics and geological interpretation.

Best practices for geologic modeling to support CO_2 storage projects can be grouped into three general topics: data considerations, model structure, and model property distribution.

6.1.1 Data Considerations

A key lesson learned through PCOR Partnership experience is that the availability of data needed for model construction, especially during early stages of a project, can vary widely between DSF and EOR storage projects. Dedicated storage projects that target DSFs often have sparse well control and other characterization data. In contrast, CO_2 EOR projects typically allow access to production history and an extensive collection of wells and accompanying data records.

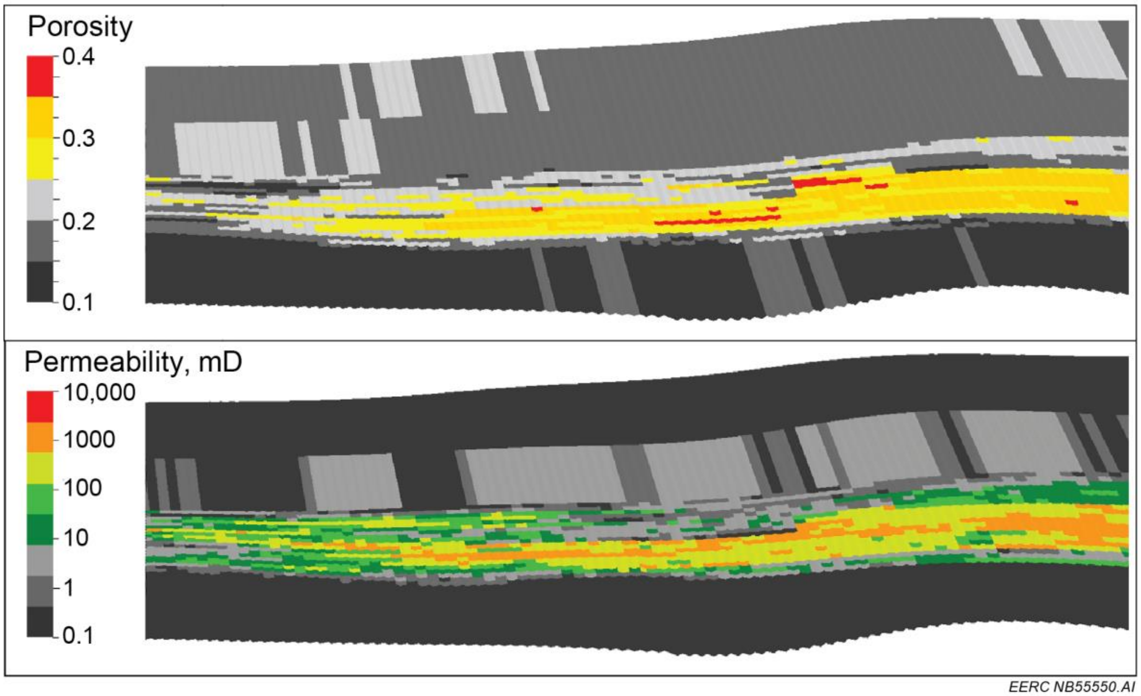

Figure 6. Model cross sections showing porosity (top) and permeability (bottom) for a reservoir interval and underlying and overlying seals. The reservoir interval shown here is approximately 9 meters in thickness, while the overlying and underlying seals are approximately 18 meters and 8 meters thick, respectively.

Data review and quality control measures ensure a sound foundation for developing models and simulation results, which is important for accurately predicting injectivity, pressure response, and subsurface migration and accumulation of CO_2.

Acquisition of characterization data may sometimes require the unavoidable initial investment of drilling a characterization well. In weighing expenses associated with characterization data acquisition, an important consideration is that in addition to providing direct modeling and simulation inputs, these data may help satisfy injection well-permitting requirements and identify cost-effective courses of action early in the project.

Among the different data types used in CO_2 storage modeling and simulation, geophysical data (with an emphasis on seismic data) have proven versatility. Well data provide 1-D subsurface measurements at specific locations, whereas seismic data provide increased visibility of interwell heterogeneity. Combining well and seismic data enables improved 3-D modeling of the subsurface. Repeated well logging and seismic survey acquisition can produce 2-D and 4-D data sets. Seismic data (depending on vintage and quality) can be very useful for structural framework creation, petrophysical property distribution, guiding simulation history matching, and use in MVA programs developed for CO_2 storage.

6.1.2 Model Structure

Proper model extent (model area and thickness, as it relates to included stratigraphy) is one of the first considerations to be addressed during model building. Decisions related to balancing grid cell dimensions and total cell count will be made early in the model construction process, and the outcome will directly affect the efficiency and precision of model construction and manipulation. Arbitrarily choosing grid cell dimensions may introduce uncertainty as to the validity of numerical simulation results. Conducting a cell size sensitivity analysis is recommended if numerical simulations will not include history matching and if simulations will be stopping short of testing ultimate storage capacity. Cell size upscaling may be needed after a model has been constructed to further reduce total cell count and enable efficient simulation.

Structural uncertainty analysis may be prudent if only a small number of structural control points exist or if there are few or no structural control points in key model locations.

6.1.3 Property Distribution

Distribution of grid cell values for dedicated or associated CO_2 storage scenarios is generally similar to standard practices of oil and gas production modeling. Necessary distributed properties for numerical simulations of CO_2 injection include 1) facies/lithology (bodies of rock with similar geologic characteristics), which is used to assign relative permeability data; 2) effective porosity; 3) matrix permeability; 4) fracture networks (if applicable) and their corresponding porosity and permeability characteristics; 5) fluid saturations (water/oil/gas/CO_2); 6) temperature; and 7) pressure.

Uncertainty analyses are an additional commonality between modeling for CO_2 storage and hydrocarbon production, undertaken to assess the likelihood of favorable outcomes across a range of realizations. Uncertainty in oil and gas models is largely focused on quantifying the location and size of reserves, estimating recoveries, and determining optimal production methods, all of which are important for operators' financial and economic decision-making processes. Uncertainty analyses in CO_2 storage modeling instead focus on determining the suitability of a particular storage complex, an optimal deployment of MVA techniques for the scale of the operation, determining storage capacity, and the likelihood of achieving safe and successful storage, all of which are important to build public assurance and acceptance.

Higher uncertainty translates to increased project risks. If the model being constructed is challenged by low data resolution (e.g., few wells for structural control and/or few or no core data sets available to guide property distributions), uncertainty analyses should be conducted to assess the range and probability of possible geologic scenarios. Such uncertainty analyses commonly include structural uncertainty, facies uncertainty, and uncertainty in petrophysical property distributions. Common nomenclature for such analyses include probabilistic realizations with statistical support, "$P_{10}/P_{50}/P_{90}$," or more arbitrary "low/mid/high" realizations for situations lacking statistical significance.

Uncertainty analysis attempts to decrease risk associated with storage capacity, injectivity, containment, injected CO_2 plume extent, and wellhead pressure necessary for injection. Uncertainty analyses highlight data gaps and provide support and guidance for acquisition of gapfilling data in future characterization activities. A case matrix may be developed, populated with combinations of model properties resulting from uncertainty analyses, and used ultimately to guide a suite of numerical simulations. Simulation outputs from the range of cases may provide additional confidence in the likelihood of project success and perhaps assist in other aspects of project planning (i.e., infrastructure design, financial/economic assessments).

6.2 Numerical Simulation

Dynamic simulation provides quantitative information to support engineering judgment and decision-making processes such as technical and economic feasibility studies, optimizing operations, identifying subsurface risks, and developing effective MVA plans. A clear definition of objectives should be developed to frame simulations in support of overall storage project goals. The accuracy and reliability of simulation outputs depend heavily on the quality of data input, including the geologic model. An understanding of underlying uncertainties of available data and interpretations is essential to constrain simulation results. Similar to modeling, a general workflow for simulation is widely understood among oil/gas production professionals and is also applicable to storage projects.

Best practices for CO_2 injection simulation can be broken into two parts: simulation design and determining the fate of injected CO_2.

6.2.1 Simulation Design

Simulation efforts are commonly employed in the oil and gas industry to estimate and optimize recovery through improving and refining operational practices. Similar to the discussion included above regarding risk and uncertainty, numerical simulation is important for operators' financial/economic investigations. Numerical simulation for CO_2 storage is used to determine the suitability of a particular storage complex and estimating injection pressure and rate, sealing effectiveness, and the likelihood of achieving safe and successful storage. All of these aspects are important to build public assurance and acceptance. More specifically, numerical simulations of CO_2 injection are conducted to 1) clearly present the process through which CO_2 will be introduced to the subsurface, 2) envision CO_2 injection consequences (e.g., reservoir pressure response, potential geochemical reactions which may affect petrophysical characteristics, impacts on recoverable hydrocarbon volumes in associated CO_2 storage scenarios) and 3) explain the predicted fate of injected CO_2 (migration and accumulation) while accounting for the various CO_2-trapping mechanisms at work in the subsurface.

History matching of existing injection and production well data (if available) is an important process for associated CO_2 storage scenarios. This process entails conducting numerical simulations of historical production and injection operations to achieve results that match well and/or field operational observations (e.g., production and injection rates and volumes, bottomhole pressures). Key model parameters may be modified through this process to enable better history matching, including permeability, fluid saturation, and relative permeability. With model parameters able to support simulations that closely match quality historical observations and data, increased accuracy is to be expected in further predictive forecasts. This process is generally followed in simulations of associated CO_2 storage, as CO_2 EOR is usually considered as a tertiary recovery operation (primary and secondary recovery data can be used in history matching).

With regard to simulations of dedicated CO_2 storage, initial forecasting is still useful and necessary for project-planning purposes, even if the operational data needed for history matching are unavailable. A suite of simulations may be conducted instead, focusing on the uncertainty analysis results to produce a range of potential outcomes. Thickness, porosity, and permeability may be varied, as well as other numerical values, to determine a range of outputs, including size and shape of the CO_2 accumulation, evolution of injected CO_2 plumes, and pressure response throughout the life of the project (during the construction, operation, closure, and postclosure phases). Modification of critical parameters may enable optimization of the project design.

6.2.2 Determining the Fate of Injected CO_2

Simulation forecasting is used to assess the long-term disposition of injected CO_2. Because the density and viscosity of injected CO_2 are less than that of the native pore fluid, the CO_2 will—over time—migrate vertically until meeting impermeable or low-permeability sealing rocks. CO_2 will also migrate laterally along permeable strata as injection pressure gradients slowly dissipate. Because this process may continue for many years after cessation of injection, simulation forecasts should extend for many years beyond to qualify effectiveness of trapping mechanisms and estimate ultimate disposition of the accumulation. A minimum of 100 years of additional simulated time is recommended, and a much longer time may be needed to better ensure stabilization of the injected CO_2. Figure 7 shows an example of a long-term simulation used to monitor CO_2 migration potential.

Four trapping mechanisms are widely recognized to retain supercritical CO_2 in deep formations: 1) structural and stratigraphic trapping, 2) residual trapping, 3) solubility/dissolution trapping, and 4) mineral trapping. Of these, structural and stratigraphic trapping occur most rapidly and should be given the strongest consideration in CO_2 storage project design, because modeling (and subsequently monitoring) these mechanisms provides the most immediate assurance that CO_2 will remain within the storage complex. Other secondary trapping mechanisms may play a significant role and greatly reduce or eliminate mobility of injected CO_2, but may be difficult to accurately predict and take place over very long timescales of hundreds or thousands of years. This understanding underscores the importance of planning CO_2 storage projects with careful consideration given to subsurface structure. Ideal structural and stratigraphic trapping scenarios include geologic examples of structural closure such as domes or anticlinal folds lacking pervasive faulting/fracturing. However, because ideal geologic conditions are not always present, modeling and simulation should be conducted for any potential storage project to ensure a safe and successful outcome.

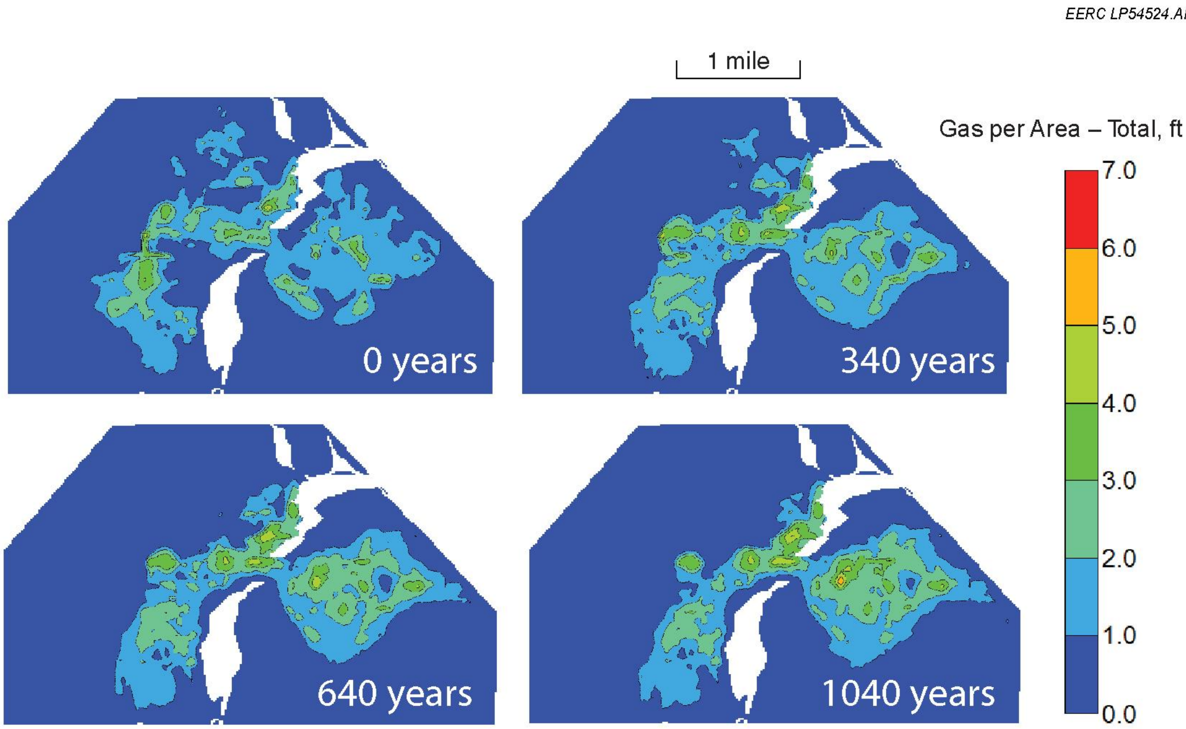

Figure 7. Gas (CO_2)-per-area maps developed from numerical simulation at different time steps after injection ceased (0 [2017], 340, 640, and 1040 years) at an EOR site. White zones in the map indicate low-permeability barriers within the reservoir. The differences observed in the time-lapse figures are subtle, in this case showing very slow eastward movement of injected CO_2 under the effects of buoyancy in the structural up-dip direction. The results here indicate that, with the assumptions included in the numerical simulations, injected CO_2 is likely to remain within the permitted area indefinitely.

CHAPTER 7: RISK ASSESSMENT

This chapter defines important risk management terminology and technical factors that are unique to the geologic storage of CO_2 and identifies the key elements informing a subsurface technical risk assessment for CO_2 storage. Several unique aspects of storage influence the application of risk management processes (e.g., the International Organization for Standardization [ISO] 31000 Framework, Figure 8).

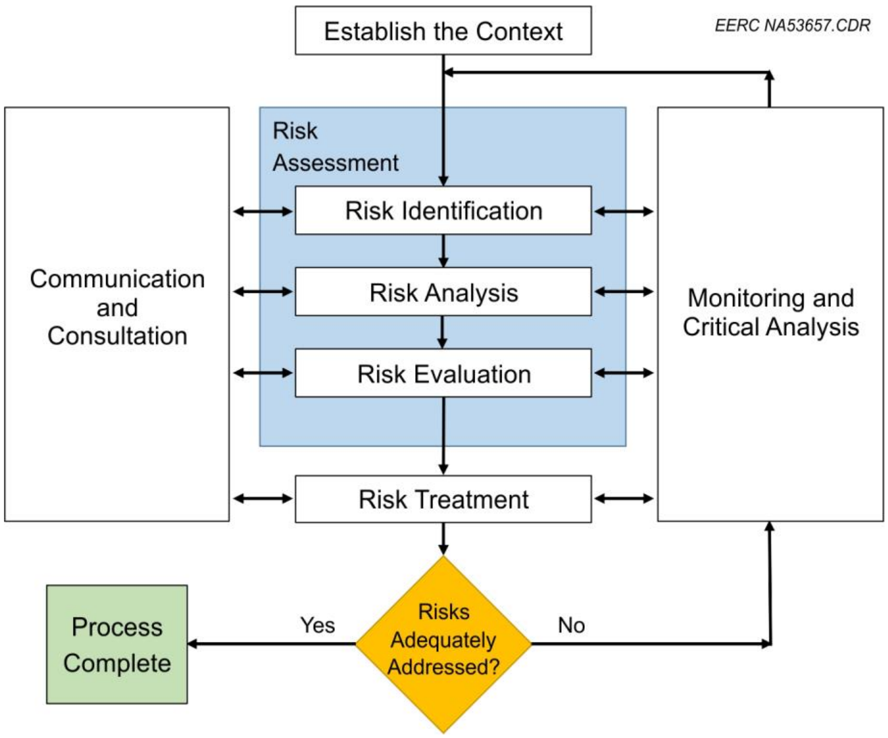

Figure 8. Risk management process adapted from the ISO 31000 (2009) standard.

The focus of this chapter is on 1) establishing the context and 2) conducting a risk assessment through risk identification, analysis, and evaluation. Discussion of risk treatment, communication and consultation, and monitoring and critical analysis are not included in this chapter. These topics are covered by the Project Management Institute (2008), ISO (2009), and the Canadian Standards Association (2012).

7.1 Risk Assessment Process for Storage

A CO_2 storage complex refers to the storage unit and seal formation(s) extending laterally to the defined limits of the CO_2 storage operation. A CO_2 storage facility is an area on the ground surface, defined by the operator and/or regulatory agency, where CO_2 injection facilities are constructed and storage activities (including monitoring) take place. The storage complex and storage facility together make up the CO_2 storage site (Canadian Standards Association, 2012). While the processes described herein are applicable to conducting risk assessments for a CO_2

storage site, the examples provided in this section are specific to subsurface technical risks (i.e., CO_2 injection into the storage reservoir or complex).

Risk is the combination of the severity of consequences (negative impacts) of an event and the associated likelihood of occurrence. In the context of storage, a risk is an uncertain event that can negatively affect operational performance and safety. Quantifying risk involves determining both the likelihood of an event occurring and the potential impact(s) to the project should that event occur. Conducting risk assessments for a CO_2 storage complex therefore entails 1) identifying potential risks that could affect the performance and safety of CO_2 storage at that location, 2) estimating their likelihood, and 3) quantifying the potential impacts associated with these risks.

Risk assessment may be defined as the iterative process of identifying, analyzing, and evaluating project risks. When applied to storage, the risk assessment process enables project developers to proactively plan and implement mitigation strategies to address unacceptable risks. Because of the long-term nature of CO_2 storage projects, which may operate from 20 to 50 years or longer, risk assessment is most effective when repeated throughout the project life cycle. This iterative process enables the evaluation of potential risks that may evolve from changing site conditions, changing site plans or designs, evolving operational activities, and/or policy and regulatory developments.

7.2 Risk Assessment for Dedicated Versus Associated Storage Sites

Addressed below are key differences in risk assessments conducted for dedicated and associated storage as well as implications for applying the process across all of the phases of a CO_2 storage project (i.e., site screening through closure/postclosure).

7.2.1 Limited Site-Specific Subsurface Characterization for Dedicated Storage Sites

The availability of site-specific data to inform the risk assessment process is generally different for dedicated and associated storage projects. Typically, a dedicated storage project targets a site for which there may be limited prior site-specific subsurface characterization data. In addition, there are few publicly available data sets from which to draw inferences because of the relative lack of commercial dedicated storage projects globally. This lack of data and experience forces dedicated storage projects to rely heavily on available generic information in the literature and other public sources to inform the early phases of the risk assessment process before site-specific data are collected (e.g., drilling of characterization wells). In contrast, associated storage will likely occur in oil fields that have decades of production history; therefore, many subsurface aspects of an associated storage site will be well characterized, likely resulting in significant available data to support the risk assessment process. In addition, extensive associated storage experience and knowledge derived from over 40 years of U.S. commercial CO_2 EOR operations are available to inform the risk assessment.

7.2.2 Existing Geologic Models and Predictive Simulations for Associated Storage Sites

Risk assessment is, by definition, future-focused. Consequently, geologic modeling and simulation-based predictions are an invaluable component of risk assessment for evaluating the long-term performance of a storage complex. Similar modeling and simulation efforts are required for both dedicated and associated storage sites, since both project types require predicting subsurface migration of injected CO_2 and other affected fluids. However, in the case of associated storage projects, established subsurface models likely already exist from prior oilfield development activities. In addition, operational data from the field's oil production allow the simulation model to be calibrated, or history-matched, to known performance data. Having existing history-matched subsurface models available at associated storage sites will yield improved predictions of fluid movement in the subsurface, which will reduce uncertainty in risk analyses related to fluid migration (Bosshart and others, 2018). At a dedicated storage site, models likely will not exist prior to the site-screening and feasibility phases of the project, which requires constructing new models from limited site characterization data, yielding larger uncertainties in model predictions and commensurately larger uncertainties in risk assessment.

7.2.3 Potential Leakage Pathways

Since both dedicated and associated storage have the goal of long-term subsurface containment of injected CO_2, the potential leakage of CO_2 from the storage complex into overlying domains of concern (e.g., USDWs, surface waters, atmosphere) represents a risk common to all storage projects. However, potential leakage pathways may differ between dedicated and associated storage projects. For example, associated storage sites will have numerous existing wellbores that penetrate the geologic strata from the surface into the storage unit; therefore, wellbore integrity represents a primary concern for potential leakage. At the same time, the history of the associated storage site as a source of oil and gas suggests that the primary seal, or cap rock, overlying the storage unit is capable of containing fluids under pressure for millennia. Alternatively, because most dedicated storage sites will likely contain few, if any, existing wellbores that penetrate the entire depth of the geologic strata, wellbore integrity may be of less concern at a dedicated storage site. Primary concerns for potential leakage at dedicated storage sites will likely focus on the continuity and integrity (ability to contain pressure and fluids over long timescales) of the primary seal that overlies the storage unit, because its properties are largely unknown.

7.2.4 Regulatory Paradigms

Regulatory regimes and correspondingly required monitoring activities for associated storage projects may also be different in scope than those implemented for dedicated storage projects, potentially resulting in different types and levels of data available to inform updates to the risk assessment. While monitoring for both project types will generally focus on tracking subsurface CO_2 migration and documenting CO_2 containment in the storage complex, monitoring programs for the two types will often differ in extent and duration because of differences in project goals and regulatory environments. For example, monitoring CO_2 EOR projects in accordance with recent EPA requirements for CCUS sites (Subpart RR – Geologic Sequestration of Carbon

Dioxide, 40 CFR Part 98.440) may not be necessary if the site operator is not seeking monetization of—or credits for—stored CO_2. Furthermore, it may not be necessary to extend monitoring at CO_2 EOR sites beyond the period of CO_2 injection. These differences will be largely site-specific and driven by applicable regulatory requirements as well as operating and management goals. At the same time, documenting associated CO_2 storage may be complicated by the number of injection wells and the recycling and processing of produced gas (including CO_2 and hydrocarbons) that accompany the oil recovered through the CO_2 EOR process.

7.3 AMA for the Risk Assessment Process

Consistent with its AMA approach to deploying storage projects, the PCOR Partnership uses an iterative approach to risk assessment. This strategy integrates site characterization, modeling and simulation, and MVA measurements with risk assessment efforts over the development phases of the project. This process ensures that the risk assessment uses the most current site data and up-to-date understanding of the CO_2 storage complex. While the risk assessment process does not change with the project phase, the increasing availability of new data and information for use as process inputs translates to more meaningful and reliable process outputs.

Risk assessment is an active process, and the relevant risks can change for a specific storage project with time and between separate phases (e.g., from site screening to feasibility). With each phase of project development, additional data become available and the uncertainty associated with the risk assessment decreases over time. Consequently, the project phase affects the nature of available information and the degree of stakeholder knowledge about the potential project risks. Each iteration throughout the process will enhance the detail in the attendant risk assessment until each of the identified risks are adequately assessed. For example, initial risk assessments conducted during the early stages of a storage project will typically be informed by high-level, regional characterization data. These initial risk assessments, while only qualitative or semiquantitative in nature, will aid the development of the project by focusing future project phases on generating the critical data needed to both quantify risks and reduce uncertainty associated with their assessment. Subsequent risk assessments will incorporate new site-specific characterization and monitoring data and updated modeling and simulation results, which act to reduce uncertainty in the risk analysis.

7.4 Application of the Risk Assessment Process to Storage Projects

Figure 9 presents a summary workflow for storage risk assessment; a discussion of key aspects follows.

EERC NA53666.CDR

Establish the Context

- Define the storage system and boundaries.
- Define the risk criteria, including probability and impact scoring tables.

Risk Identification

- Conduct elicitation of internal and external stakeholders and subject matter experts.
- Use an independent risk management expert to facilitate the process.
- Aggregate all available site characterization, geologic modeling, and reservoir simulation results to assist in the process.
- Generate a functional model of the storage site, including system components or subsystems, functions of each component, and system interactors.
- Ensure that the following four technical risk categories are considered, as these are common among storage projects: 1) storage capacity; 2) injectivity; 3) lateral and vertical containment of CO_2 or formation fluids, including oil for CO_2 EOR sites; and 4) induced seismicity.
- If this is a risk assessment update and the team is beginning with a prior risk register, then modifications to the risk register should be thoroughly documented for future reference. Moreover, the original risk register entry numbers should be retained for consistency over the project life cycle. New risks should be appended to the end of the original risk register list.

Risk Analysis

- Develop a set of quantifiable physical consequences and a means to link these physical consequences to project impacts.
- Consult predictive simulations to estimate probabilities associated with risks related to injectivity, storage capacity, and lateral and vertical containment of CO_2 and other fluids.
- Use an electronic template to capture risk scores from the respondents.
- Prior to finalizing a set of risk scores, verify outlying scores (extremely low or high scores relative to the group of scores) with individual experts.
- Quantify the uncertainty in the risk scores using either visual tools such as heat maps or statistical measures such as the expected value and standard deviation.

Risk Evaluation

- Plot each individual risk onto a risk map, which plots the risk probability score against the risk impact score.
- To evaluate uncertainty in the risk scores, generate risk maps for both the expected value and maximum risk scores.
- If a more quantitative risk evaluation is needed, employ probabilistic methods such as Monte Carlo simulation.

Figure 9. Best practices procedure for CO_2 storage project risk assessments.

Probability scores for storage projects are generally assigned through expert opinion because—due to the early-stage commercial status of storage projects—direct measures of long-term project failure rates or similar quantitative measures are often not available. Table 1 provides an example five-point scale for discrete probability ranges used for PCOR Partnership risk assessments. Table 2 presents an example of potential impacts.

Table 1. Example Risk Probability Scores Used for Storage Projects

Minimum Probability over Reference Period	Average Probability over Reference Period	Maximum Probability over Reference Period	Frequency Level	Definition
75%	88%	100%	5	Very high
25%	50%	75%	4	High
5%	15%	25%	3	Moderate
1%	3%	5%	2	Low
0%	<1%	1%	1	Very low

Note: probabilities calculated based on a statistical analysis of individual expert panelist scores. This table shows a linear scale, but frequency levels can also be assigned using a logarithmic scale.

Table 2. Example Risk Impact Criteria for Different Project Attributes

Project Attribute	Estimated Impact 1 Very Low	2 Low	3 Moderate	4 High	5 Very High
Cost	Insignificant cost increase	<10% cost increase	10%–20% cost increase	20%–40% cost increase	>40% cost increase
Schedule	Insignificant time increase	<5% time increase	5%–10% time increase	10%–20% time increase	>20% time increase
Scope	Barely noticeable scope change.	Minor areas of scope are affected.	Major areas of scope are affected.	Scope change is unacceptable to sponsor.	Project objectives cannot be met.
Quality	Barely noticeable quality degradation.	Only very demanding applications are affected.	Quality reduction requires sponsor approval.	Quality reduction is unacceptable to sponsor.	Project end item is effectively useless.

During the first risk assessment of a storage project, at either screening or feasibility stages of the AMA, the risk identification process begins with a preliminary list of potential storage-related risks assembled from a basic understanding of the storage site combined with an existing open-access database of potential risks associated with geologic storage of CO_2 (e.g., Quintessa, 2014). Internal and external stakeholders use this preliminary list along with functional knowledge of the storage complex to identify potential project risks. An important aspect of the initial risk identification phase is to determine the level of specificity required to adequately assess risks. For example, Azzolina and others (2017) discussed how a single physical consequence of storage could be caused by multiple failure causes, resulting in a relatively large number of individual risks. Ultimately, the level of detail with which risks are described in the risk register will be project-specific and may depend on project development phase.

A major component of the risk identification process is failure modes and effects analysis (FMEA), with an evaluation of where the storage complex might fail (i.e., failure mode: What could go wrong?) and how it might fail (i.e., failure cause: Why would the failure happen?). The results of this functional analysis can be cross-referenced with existing databases for CO_2 storage projects to develop a comprehensive list of potential failure modes and causes, which together comprise the subsurface technical risks to the CO_2 storage complex. Technical staff and subject matter experts should review the list of potential subsurface technical risks developed through FMEA and, if necessary, refine this list to prepare a final project-specific risk register. The final risk register should only include those risks that have been validated by experts or project leaders as relevant to the project.

Subsequent risk assessment updates during later phases of the storage project should use the existing risk register as a starting point and modify the register as necessary to accommodate new risks or to remove risks no longer relevant to the project. If the project team recognizes that a particular risk is no longer relevant, then it may be removed from the risk register; however, the reasoning as to why it was removed should be documented to provide a detailed accounting of the rationale for the action. Similarly, new risks identified during later phases should be appended to the end of the previous risk register, and this addition should be documented.

Risk analysis relies on the criteria developed while establishing the context of the risk assessment and includes 1) scoring risk probability and risk impact, 2) finalizing the risk scores that will be used in the risk evaluation phase, and 3) quantifying uncertainty in the risk scores. A systematic, semiquantitative risk analysis should be performed by asking subject matter experts.

While available site data and predictive simulations are used to estimate a risk probability score, a commonly occurring challenge is linking technical risks, such as potential leakage, to a project impact (e.g., cost). This aspect of risk analysis can be supported by describing physical consequences as specific, measurable metrics, subsequently translated to risk impact scores. This relationship between physical consequence and risk impact scores should reflect specific concerns of key storage project stakeholders.

Expert elicitation aims to achieve scientific consensus; however, inconsistent risk scores may result from the variations inherent in natural systems, incomplete information at the time of the assessment, and differences in expert opinion. These factors may be exacerbated for storage projects because of the inherent levels of uncertainty with regard to the deep subsurface, particularly in the context of dedicated storage in early phases of the AMA. Therefore, capturing and quantifying uncertainty in the scores prior to the evaluation stage is an integral component of risk analysis.

Statistical metrics such as expected value and standard deviation can be used to quantify variability in risk scoring. Risk scores with a large standard deviation around their expected value represent greater uncertainty among subject matter experts. Azzolina and others (2017) provided an example of using heat maps for CO_2 storage as an effective visual tool for understanding variation in risk-scoring across a large number of respondents. These heat maps allow the project management team to quickly assess the risk scoring in a single diagram. Large variation may stem from true uncertainty about the nature of a particular risk, given the current information at the time of the assessment. Alternatively, large uncertainty may reflect misunderstandings and/or different perspectives among subject matter experts about the specific risk. If warranted, these risks can be reassessed to ensure a final, representative set of risk scores.

The purpose of risk evaluation is to assist in making decisions about which risks require treatment based on the outcome of risk analysis and priority for treatment implementation (International Organization for Standardization, 2009). Two useful approaches include risk maps and probabilistic techniques such as Monte Carlo simulation.

A risk map is a method for evaluating the quantitative results of the risk analysis by plotting—for each individual risk—probability score on the y-axis and risk impact score on the x-axis. Using this approach, lower-probability, lower-impact risks plot in the lower left-hand corner of the map, while higher-probability, higher-impact risks plot in the upper right-hand corner. Figure 10 provides an illustrative example of a risk map for a dedicated saline storage project. The black dots in Figure 10 represent discrete risks, plotted according to their individual probability and impact scores.

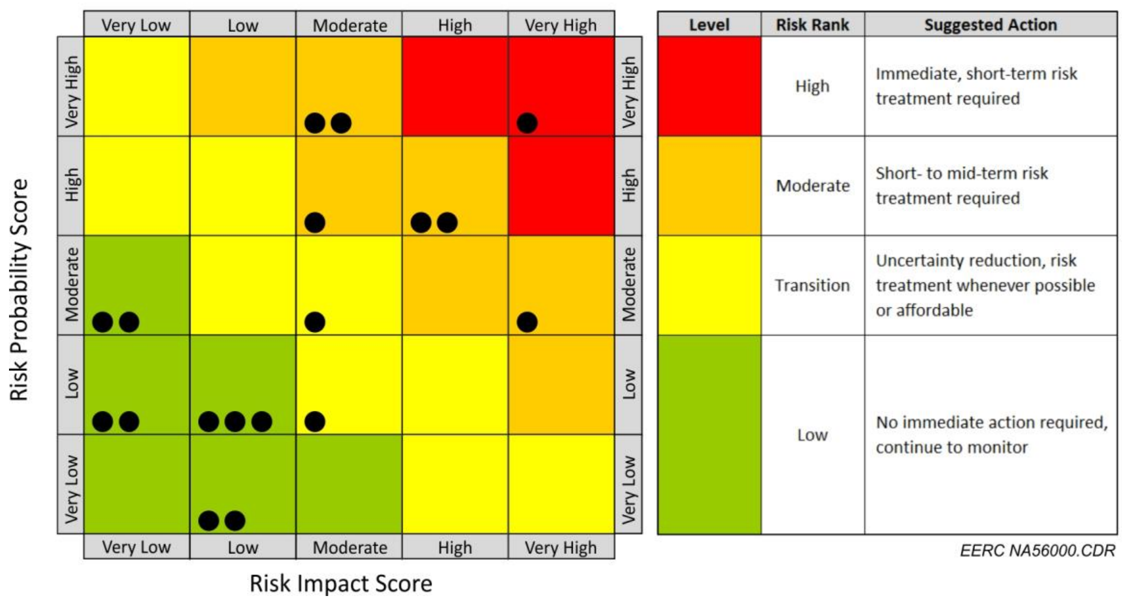

Figure 10. Illustrative example of a risk map for a dedicated saline storage project showing the ranking of individual risks and the suggested actions for the different risk ranks.

To capture a statistical range of potential outcomes and assess total project risk profiles, a supplemental approach can also be implemented using probabilistic analysis such as Monte Carlo simulation, which involves generating multiple outcomes (realizations) using the underlying statistical distribution of the input variables (i.e., the risk probability and impact scores for each individual risk). Simulated outcomes are then compiled for all risks in the risk register to estimate total project risk.

CHAPTER 8: MONITORING, VERIFICATION, AND ACCOUNTING

MVA is an AMA core technical element that includes monitoring subsurface CO_2 injection, verifying that injected CO_2 is permanently stored and not migrating into undesired strata, and accounting for the amount of CO_2 that has been permanently stored, typically for the purposes of deriving greenhouse gas emission reduction credits (e.g., American Carbon Registry, 2015). This chapter does not address the accounting component of an MVA program, focusing instead on monitoring activities meant to provide storage verification data that may be required by a permitting entity or useful in conveying project success and safety to stakeholders. Monitoring activities also inform the other AMA core technical elements by providing data that are used to history match and update 1) geologic models and predictive simulations, 2) the risk profile, and 3) current understanding of subsurface characteristics.

The particular geologic setting and characteristics of a storage complex require a site-specific approach to monitoring and verification. Rather than define a prescriptive monitoring program, this chapter focuses on the systematic planning process for building and implementing a site-specific storage project-monitoring program. Generally, monitoring activities should be risk-driven, based on the project risk assessment, with specific monitoring techniques and strategies aimed at adequately evaluating or addressing project risks.

8.1 Development of a Monitoring Program

The primary goals of monitoring are to collect measurements needed to provide assurance of CO_2 storage complex integrity and data needed to comply with storage verification regulatory requirements. Developing a monitoring program that achieves these goals requires establishing monitoring objectives, selecting monitoring techniques, establishing baseline conditions, and conducting operational and postclosure monitoring.

8.1.1 Establish Monitoring Objectives

While monitoring objectives for dedicated and associated storage projects may share many commonalities, markedly varying risk drivers and practical considerations may significantly influence overall monitoring program design. For example, CO_2 EOR projects typically have greater numbers of wellbores intersecting the reservoir. Because these existing wells represent potential pathways for out-of-zone CO_2 migration from the reservoir into the overlying strata, well monitoring is often a priority for CO_2 EOR operations and associated storage assessment. Conversely, while dedicated storage sites may have few reservoir-penetrating wells, the resulting lack of historical subsurface characterization data may translate to greater uncertainty regarding sealing formation containment properties. Monitoring program objectives typically include assessing a set of general criteria that address 1) migration and accumulation of CO_2 within the storage formation and AOR, 2) potential leakage pathways, and 3) shallow and surface environmental characteristics that may be sensitive to and indicative of increasing CO_2 concentration. Therefore, monitoring can be essentially divided into two parts, which respectively focus on 1) the deep subsurface and 2) the shallow/surface environment.

The importance of the criteria discussed in the following sections depends on site-specific conditions in combination with stakeholder concerns and regulatory requirements. Depending on the storage project and site-specific conditions, each of these criteria may relate to multiple individual risks. Consequently, the project-specific risk assessment is generally the best starting point for establishing a comprehensive set of monitoring objectives.

Deep Subsurface Monitoring

The intent of deep subsurface monitoring is to generate information regarding the disposition of CO_2 injected into the storage reservoir(s). This information may provide the means to assess the degree of agreement between actual/measured subsurface conditions and predictive simulations. Additionally, subsurface-monitoring data may be useful in determining operational risks. Specifically, deep subsurface monitoring may assist investigations of the following:

1. Vertical containment. Injected CO_2 and other reservoir fluids should remain within the storage complex. Injected CO_2 is typically buoyant compared to native brine and other reservoir fluids and will, therefore, tend to rise upward over time. Therefore, monitoring data that can support ongoing risk evaluation of the integrity of overlying seals and penetrating wellbores provide information about vertical containment of CO_2 in the reservoir.

2. Lateral migration. Storage reservoirs may or may not have physical boundaries that prevent lateral flow of CO_2 beyond a certain distance (e.g., changes in lithology). Lateral migration of CO_2 beyond the planned extent could change the likelihood of certain risks, for example, by bringing injected CO_2 into contact with potential leakage pathways like existing wells or other subsurface features. In some cases, issues of pore space ownership or other private rights (e.g., trespass) may also be affected.

3. Induced seismicity. Changes to subsurface pressure and stress regimes resulting from subsurface fluid injection or extraction have the potential to generate seismic activity by either reactivating or creating faults and/or fractures. In the case of CO_2 injection operations, data from both associated and dedicated storage-monitoring programs have indicated that, in cases where seismicity has been induced, the magnitude of these events is very small (microseismicity) such that resulting risks are low. However, monitoring microseismicity, both natural and induced, using passive monitoring techniques can be used to provide assurance to third-party stakeholders and regulators that induced seismicity, if it occurs, is manageable and does not represent an unacceptable project risk.

4. Wellbore integrity. Existing wells may provide a potential CO_2 migration pathway from the reservoir to the overlying strata and represent a risk scenario for many sites, especially in cases such as some onshore CO_2 EOR projects where significant numbers of existing wells intersect the storage reservoir.

Shallow/Surface (Environmental) Monitoring

Appropriately selected and characterized storage sites should have low and manageable risks associated with unintended migration of CO_2 or other reservoir fluids out of the storage complex. Nevertheless, monitoring of relatively shallow, surface, and atmospheric environments may be required to augment deep subsurface monitoring, thereby providing additional assurance to stakeholders. Typical onshore environmental monitoring programs focus on characterization of:

1. Groundwater chemistry, especially shallow aquifers that represent potentially significant resources for potable supply or other uses.

2. Surface water chemistry, including wetlands, lakes, ponds, rivers, and streams.

3. Soil gas composition in the soil vadose zone, which typically contains natural, highly variable concentrations of biogenic CO_2 and other gases.

4. Atmospheric composition above and adjacent to the storage site.

In contrast to deep subsurface conditions that are typically slow to change, chemical and physical properties of groundwater, surface water, soil gas, and the near-surface atmosphere are subject to strong seasonal effects and influenced by a wide range of natural processes and human activities. For this reason, baseline conditions should be established where possible over multiple seasons to quantify the natural background variability of these systems and to establish action levels (threshold concentrations) of key parameters that could be indicative of leakage and, therefore, warrant further investigation. In this context, wider regional environmental monitoring beyond the planned extents of the storage project can provide valuable supplemental data to help quantify the natural background variability of these systems.

8.1.2 Select Monitoring Techniques

Many different techniques are available for monitoring CO_2 and other fluids in the deep subsurface and shallow/near-surface environments (e.g., Canadian Standards Association, 2012; U.S. Department of Energy National Energy Technology Laboratory, 2017; IEA Greenhouse Gas R&D Programme, 2018). An extensive discussion of specific monitoring techniques is beyond the scope of this document. A more comprehensive discussion of specific monitoring technologies tested as part of PCOR Partnership activities is included in the PCOR Partnership Best Practices Manual – Monitoring for CO_2 Storage (Glazewski and others, 2018). Instead, this discussion focuses on general considerations for selecting monitoring techniques and the value of integrating multiple monitoring techniques to achieve project monitoring objectives. While the final selection of monitoring techniques will be site-specific, general considerations for selecting monitoring techniques include:

- Data quality objectives (DQOs). Monitoring data collected/generated should be of sufficient quality to satisfy criteria for establishing risk indicators, which are parameters that can be measured as a means of indicating whether and to what extent a risk is being realized. Key criteria include completeness, redundancy, sensitivity, time to detection, and measurement scale. Monitoring data should also be capable of serving as inputs to validate and/or revise geologic models and numerical simulations.

- Site-specific geologic constraints. The storage reservoir and overlying formations will have site-specific characteristics that can influence effectiveness of a given monitoring technique. For example, a thick geologic layer composed primarily of salt can inhibit the effectiveness of seismic measurements. Geologic constraints should be a key factor in determining which monitoring technologies are capable of achieving the established DQOs.

- Financial constraints. Collecting multiple rounds of monitoring measurements (e.g., quarterly sampling) over project baseline, operational, and closure/postclosure phases (perhaps 20 years or longer) may make certain monitoring techniques cost-prohibitive. Therefore, cost can be a key factor in selecting a monitoring technique that is capable of satisfying the monitoring objectives and achieving the DQOs. In general, approaches should be evaluated to minimize the cost and maximize the value of a monitoring program by combining and integrating monitoring technologies from across a spectrum of options.

- Regulatory requirements. Certain regulatory requirements may dictate specific monitoring activities. A monitoring program should comply with all applicable federal, state/provincial, and local regulations.

- Additional risk and impact. Some monitoring techniques may introduce additional risk or cause localized impacts during implementation. For example, installation of a storage reservoir-monitoring well (that necessarily penetrates the overlying seal formation) introduces a potential fluid migration pathway for out-of-zone migration of CO_2 or other fluids. Similarly, a 3-D surface seismic survey requires access to the land within and in proximity to the AOR, which may affect landowners or local wildlife. These and other secondary impacts must be identified and factored into the selection process when developing an integrated monitoring strategy.

- Stakeholder/landowner concerns. The local community and land use within and around the storage project can affect the selection of monitoring techniques. For example, dense population centers or landowner sensitivities may limit access to private properties, which could affect successful implementation of monitoring activities.

All of the above factors should be considered when developing a site-monitoring strategy. The combination of selected monitoring technologies needs to achieve all monitoring objectives including compliance with all applicable regulations, be cost-effective, and minimize secondary environmental/risk impacts and concerns of stakeholders and landowners.

8.1.3 Establish Baseline Conditions

Baseline monitoring data (i.e., measurements performed prior to CO_2 injection) are performed to provide context for the interpretation of subsequent operational and postclosure measurements regarding 1) subsurface migration and containment of injected CO_2 and 2) shallow and surface environmental conditions.

Use of Previously Existing Site Characterization Data Sets

Site characterization data sets acquired for most storage projects typically include a combination of previously existing data sets (historical data collected prior to storage project initiation) and data generated via additional site characterization activities (conducted specifically for the storage project) such as well logging, analysis of core samples or fluid samples, or geophysical surveys. As a first step toward establishing a monitoring baseline for the deep subsurface, the project team should assess the quality and completeness of available site characterization data and evaluate the need for additional data acquisition. Because deep subsurface data represent features and properties of the storage reservoir that are typically slow to change, even relatively old data—provided they are of sufficient quality—can often be of significant value. Key considerations regarding the possible need for updating and/or supplementing available site characterization data to improve the accuracy in establishing baseline conditions are:

- Quality of the existing site characterization data (e.g., Have appropriate data collection protocols been employed and adequately documented?), especially data describing the storage and sealing formations.

- Reliability of the sampling and/or analytical/characterization techniques used for data acquisition.

- Possibilities for reprocessing historical seismic data using new software capabilities or through calibration of the existing data against additional measurements such as downhole pressure, well logging, and sample collection and analysis. Alternatively, more expensive and time-consuming options such as new seismic surveys or drilling campaigns may be necessary to confirm previous site characterization findings and definitively establish baselines for the deep subsurface.

- Knowledge or evidence of potential activities (e.g., well drilling, oil/gas production, produced water disposal) that may have occurred since acquisition of the historical site characterization data and have the potential to cause changes in the subsurface.

Risk-Driven Emphasis

The adequacy of characterization data for establishing a monitoring baseline in the deep subsurface should also be evaluated in the context of potential subsurface risks. Typically, higher-ranking risks (i.e., those risks assessed as likely to occur and with the potential to result in significant impacts), should be given high priority by ensuring that critical subsurface baseline data are collected that permit an accurate assessment of these risks over the duration of site operation.

Unique Aspects of Baseline Environmental Monitoring

Environmental monitoring generally encompasses groundwater, surface water, soil gas, and the near-surface atmosphere, with greater emphasis generally placed on groundwater and soil gas monitoring. As noted previously, in contrast with deep subsurface monitoring, the near-surface and surface environment are subject to seasonal effects and influenced by a wide range of natural processes and human activities unrelated to subsurface injection of CO_2. It should be noted also that CO_2 occurs naturally in soils and the shallow subsurface because of biogenic processes. Consequently, risk indicators in groundwater and soil gas typically have greater variability, which increases the importance of developing a baseline data set that is capable of quantifying this variability and integrating this information into the risk analysis. Establishing baseline conditions for environmental monitoring typically includes time series analysis of vadose zone soil gas, groundwater, and selected surface water samples for the following:

Vadose Zone Soil Gas

- Concentrations of CO_2, methane, ethane, oxygen, nitrogen, and volatile organic hydrocarbons (VOCs).

- Other parameters necessary to address site-specific risks and/or regulatory requirements.

Groundwater and Selected Surface Waters

- Parameters indicative of the presence of CO_2 (such as pH, alkalinity, and dissolved CO_2) or the presence of brine (such as conductivity or TDS).

- Other parameters necessary to address site-specific risks and/or regulatory requirements.

8.1.4 Conduct Operational and Postclosure Monitoring

With the beginning of CO_2 injection, the monitoring program transitions from baseline to operational monitoring, which serves a different function. Whereas the goal of baseline monitoring is to quantify the natural background variability of the risk indicators, the goal of operational monitoring in the deep subsurface is to determine the migration of CO_2 within the storage complex. For the shallow subsurface, operational monitoring is used to detect any significant deviations from baseline conditions that warrant further investigation. The operational monitoring plan will initially mimic the sampling plan and schedule of the baseline monitoring plan. However, as the operational monitoring program progresses and yields more information about storage complex performance and behavior of injected CO_2, the sampling plan and schedule will likely evolve. For example, operational monitoring activities may decrease in frequency, scope, or both if no significant changes from baseline conditions occur over time. At the same time, if a significant subsurface anomaly is detected, the scope of the operational monitoring plan will need to be adjusted to focus on monitoring the anomaly until it is understood. In both cases, the goal is to accurately monitor the risk profile of the site during subsurface CO_2 injection.

When CO_2 injection ceases, a storage project transitions into the closure/postclosure phase. Monitoring activities during this phase are focused on ensuring the injected CO_2 remains contained within the storage complex and AOR and does not pose unacceptable risks. While the monitoring plan employed at the beginning of this phase will likely be the same as at the end of the operational phase, monitoring frequency and extent will likely be reduced as field observations and geologic models and simulations confirm the CO_2 plume is stable over time (e.g., years to decades) and is adequately contained. The ultimate goal of postclosure monitoring, in concert with the models and numerical simulations, is to demonstrate that the project site meets closure certification requirements and is suitable for final abandonment and transfer of ownership and liability to state governments or other interested private parties.

CHAPTER 9: INTEGRATED CASE STUDIES

Two case studies presented in this section describe theoretical examples of potential CCUS projects in the PCOR Partnership region, highlighting key examples of the application of technical elements of the AMA. The two case study scenarios represent, respectively, a hypothetical dedicated CO_2 storage project and an EOR project with associated CO_2 storage.

9.1 Case Study 1: Dedicated CO_2 Storage

Case Study 1 summarizes the stepwise development of a hypothetical dedicated storage project. The project goal was to permanently store 25 Mt of CO_2 sourced from a coal-based energy generation facility in a DSF over a 25-year period. A surface map of the project area is shown in Figure 11.

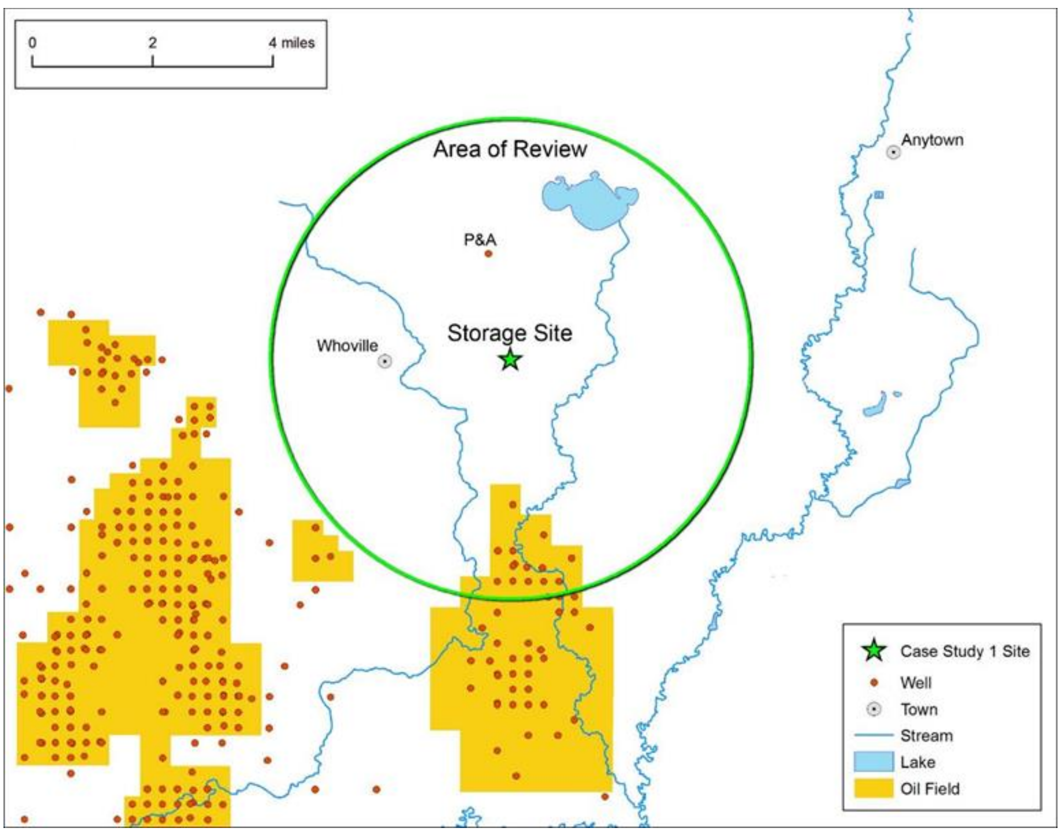

Figure 11. Map of Case Study 1 project area.

9.1.1 Site Characterization

During site screening performed by the operator, available subsurface data describing known geologic formations within the region of interest were gathered and reviewed, with the objective of identifying potential storage targets and sealing layers. Data from previously performed regional

2-D and 3-D seismic surveys (existing data) were obtained. Core sample descriptions and analyses from proximal locations were acquired. Well records and logs throughout the region were compiled. All of the available data were used to characterize subsurface geologic conditions, especially those related to storage reservoir injectivity, capacity, and integrity. An important point to note is that maximizing the use of available data in screening and feasibility phases of the AMA is a best practice in supporting go/no-go decisions between project phases. In addition, making full use of available data can both reduce the scope of, and better target, more expensive field investigations such as well drilling and seismic surveys.

Potential storage formations and well locations were selected based on data analysis and interpretation. With an estimated capacity of 25 Mt of CO_2, the basal Cambrian storage complex, a sequence of clastic rocks (alternating sandstones and shales) making up the Deadwood and Black Island Formations, met initial screening requirements. The proposed storage complex was 6000 feet below ground level and 150 feet thick, contained brine with salinity greater than 10,000 ppm TDS (therefore not considered a USDW), and was overlain by 300 feet of shale sealing layers. The reservoir was normally pressured, and the strata dipped gently to the north at approximately 1 degree.

While this level of understanding was sufficient for initial screening, more data were needed to better understand the distribution of rock properties within the storage complex, a common challenge for dedicated storage projects. Progression into a feasibility study and subsequent project phases would require acquisition of additional data through exploration well drilling and associated sampling and analysis activities and/or conducting new or upgrading existing seismic surveys.

9.1.2 Modeling and Simulation

Using relevant site characterization data, geologic model construction and numerical simulation of CO_2 injection were undertaken in the project feasibility study phase to derive an initial assessment of storage performance, assist in MVA technology selection and deployment planning, and support regulatory permitting. An industry-standard software was used to create a geologic model depicting the structure and interpreted distribution of rock properties for the planned injection formation and overlying seal.

As mentioned above, limited site-specific data were available to inform initial model construction. To somewhat compensate for this deficiency, the initial model extent was expanded to encompass significantly greater area than the expected AOR, which enabled the use of additional data from the greater region. Uncertainty analyses were performed, yielding a series of realizations with varying structure (and injection formation thickness), distribution and relative proportions of rock types (sandstone and shale), and petrophysical properties (porosity and permeability). The resulting realizations ranged from conservative to optimistic in terms of these rock properties and their suitability for CO_2 injection. Other distributed properties included temperature, pressure, brine salinity, and water saturation (because no hydrocarbons were expected within the study area, water saturation was 100%).

Using the suite of realizations, a numerical simulation case matrix was drawn up to assist planning of numerical simulation activities. In early project stages, understanding the range of potential outcomes is necessary to inform subsequent project efforts, including characterization data acquisition, risk assessment, site development, infrastructure cost estimation, and MVA program planning and deployment. Therefore, a series of numerical simulations of CO_2 injection realizations were chosen, spanning conservative, expected, and optimistic conditions. Perhaps the most important cases considered were the expected and conservative conditions, as promising simulation outcomes based on these cases would provide the greatest confidence in the likelihood of project success as it relates to subsurface technical risk(s).

Simulation models were initiated for each of the selected cases. Injection well locations and characteristics were defined (tubing size, specific injection interval), well-operating constraints were specified (maximum injection rate, maximum bottomhole pressure), and other dynamic variables were input (CO_2–brine relative permeability, boundary conditions [open versus closed model boundaries]). No history matching was attempted, as previous operational data within the area did not exist. The chosen cases were then simulated using an industry-standard software.

Predictive simulation results across the range of realizations indicated that at least two (and perhaps as many as four) injection wells would be required to meet project objectives. Injected CO_2 plumes were expected to have radii of 0.5–1.5 miles after 25 years of injection. The properties estimated and populated in the overlying seal indicated virtually no vertical migration of simulated injected CO_2. The resulting pressure increase within the injection interval was expected to affect approximately 130 square kilometers, an area much greater than the footprint of injected CO_2, and therefore likely to be the determining factor in future Class VI well-permitting criteria related to AOR determination.

Although these results were important for immediate project planning and design activities, further reduction in technical uncertainty was needed, which called for additional site-specific data acquisition activities, including construction of a characterization well, well logging, and core and fluid sample recovery and analysis.

9.1.3 Risk Assessment

An initial risk assessment was conducted, using a panel of technical experts and project stakeholders, in the feasibility study project phase to highlight potentially unacceptable risks and identify additional data needs. A generic register of potential technical and nontechnical risks, relevant to a dedicated storage project, provided a framework to review site-specific information. The panel screened out inapplicable or insignificant issues before scoring, ranking, and mapping remaining risks.

The risk assessment identified a number of risks posed by a general lack of site-specific data. Another important risk identified was that CO_2 injection at the planned site had the potential to impact nearby oil pools currently under commercial production (Figure 11). The operator viewed this as an unacceptable risk, which led to a second iteration of the AMA. This second pass through the AMA technical elements included gathering additional, targeted site characterization data; development of revised and improved geologic models and numerical simulations; and conduct of a second risk assessment. Outputs of the second AMA iteration revealed that by moving the two planned CO_2 injection wells approximately 5 kilometers east of the originally proposed location, overall project risk was reduced to acceptable levels, largely attributable to decreased likelihood of impacting the nearby oil pools. The operator used this information to inform a go/no-go decision point, whereby it was decided to move the injection well and proceed toward operation.

9.1.4 MVA

Risks identified for the site and surface conditions strongly influenced the development of a monitoring program during the project design phase. The injection site lay within an expansive area of flat agricultural land, and a small lake and two small rivers were within the AOR. An aquifer at a depth of 200–600 feet was penetrated by extraction wells to provide potable water for homes and agricultural operations. A plugged and abandoned oil well penetrating the formation of interest was also located within the AOR. A township community of 200 residents was located to the west of the injection site (Whoville).

With the surface sensitivities identified, the framework for a monitoring program was outlined. Surface water and groundwater monitoring were deemed necessary to engender stakeholder confidence that the project would not adversely impact wildlife habitat and potable water resources. Because the abandoned well represented a potential vertical migration pathway for injected CO_2 and/or injection formation brine, the plugging records were scrutinized to gauge potential leakage risk. The residents of Whoville were broadly supportive of the oil industry, because of its positive impact on regional employment and economic stability. And although community support for the project was strong, public outreach events were conducted to provide a forum for community members to voice concerns and enable the operator to convey a clear understanding of how risk mitigation and MVA activities would address those concerns.

With the above criteria established, the monitoring program for this dedicated storage project was designed to:

- Establish a baseline for both reservoir and environmental conditions.
- Ensure comparability of data used for establishing baseline (pre-CO_2 injection) conditions and monitoring data generated during project operational, closure, and postclosure phases.
- Demonstrate that CO_2 was safely injected and securely contained within the reservoir while minimizing overall monitoring cost.
- Support development and validation of reservoir simulation predictive models.
- Demonstrate that long-term risks were sufficiently low at cessation of CO_2 injection to permit closure certification and surrender of the site.

Following the above guidance, the MVA plan included 1) surface water, groundwater, and soil gas quality monitoring; 2) pressure and temperature monitoring; and 3) seismic acquisition and monitoring.

Surface Water, Groundwater, and Soil Gas Quality Monitoring

During final design and construction, a shallow/surface monitoring program comprising surface water, groundwater, and soil gas monitoring established baseline conditions. Standard sampling and analytical protocols ensured generation of defensible data sets.

Since chemical concentrations in groundwater systems typically have less variability than surface waters and soil gases, groundwater monitoring provides greater sensitivity for detecting changes from baseline conditions. In addition, groundwater systems are deeper (closer to the storage reservoir), thereby enabling more timely detection of potential deviations from baseline conditions that could be indicative of CO_2 leakage or migration of brine from the injection formation.

Groundwater monitoring was focused on measuring key indicators of CO_2 presence (e,g., pH, alkalinity, and dissolved organic carbon) using field-based methods. Surface and groundwater monitoring were conducted in the field using relatively inexpensive handheld instrumentation and field test kits. Field methods for monitoring risk indicators such as pH, conductivity, and alkalinity are generally sensitive enough to detect a deviation from baseline conditions that would then trigger a more detailed investigation into probable cause, if necessary. A plan was in place to conduct more intensive analyses if screening-level measurements detected significant deviation from baseline measurements, although this was never required.

Monitoring of soil gas focused on areas around the plugged and abandoned well, a dedicated monitoring well, and the CO_2 injection well, since they represented the most likely pathways for potential CO_2 migration from the reservoir to the surface. The initial suite of soil gas analyses was comprehensive in scope, encompassing a broad list of risk indicators/analytes, with the expectation that the list would be shortened as warranted by analysis of acquired data. Samples for laboratory analysis were collected to help define baseline conditions and for periodic quality assurance purposes during operations, but a majority of monitoring employed handheld instrumentation to facilitate prompt analysis of data and reduce costs.

Pressure and Temperature Monitoring

A dedicated monitoring well enabled detection of pressure and temperature changes in the reservoir as indicators of CO_2 plume migration. Pressure and temperature gauges were installed in the storage formation, in the primary sealing formation, and in additional formations above the sealing formation to monitor potential fluid migration. These data have a high acquisition frequency, enabling real-time measurement of the storage operation and providing confidence that wellbore and subsurface conditions are within normal (predicted) limits. If operational anomalies were to be encountered, these data would enable initial diagnostics to investigate possible causes, including wellbore integrity, scaling, and corrosion leading to CO_2 leakage.

Operational monitoring data from the injection well provided measurements of CO_2 injection rate, wellhead temperature and pressure, and bottomhole temperature and pressure. A distributed temperature-monitoring system collected temperature profile measurements along the injection wellbore. These data allowed detection of subsurface fluid migration and any potential leakage beyond the storage complex.

Seismic Acquisition and Monitoring

Acquisition of 4-D seismic data, although relatively expensive compared to other technologies, provided an essential and cost-effective component of the monitoring program for this site. The choice of permanent seismic array (Figure 12), following negotiated agreements with landowners, significantly reduced long-term costs and enabled more frequent time-lapse surveys. An initial survey prior to initiation of CO_2 injection illuminated reservoir structure and heterogeneity and established baseline conditions. Subsequent time-lapse surveys during operations tracked changes in pressure and CO_2 migration and saturation, allowing history matching to increase the accuracy of subsequent predictive simulations.

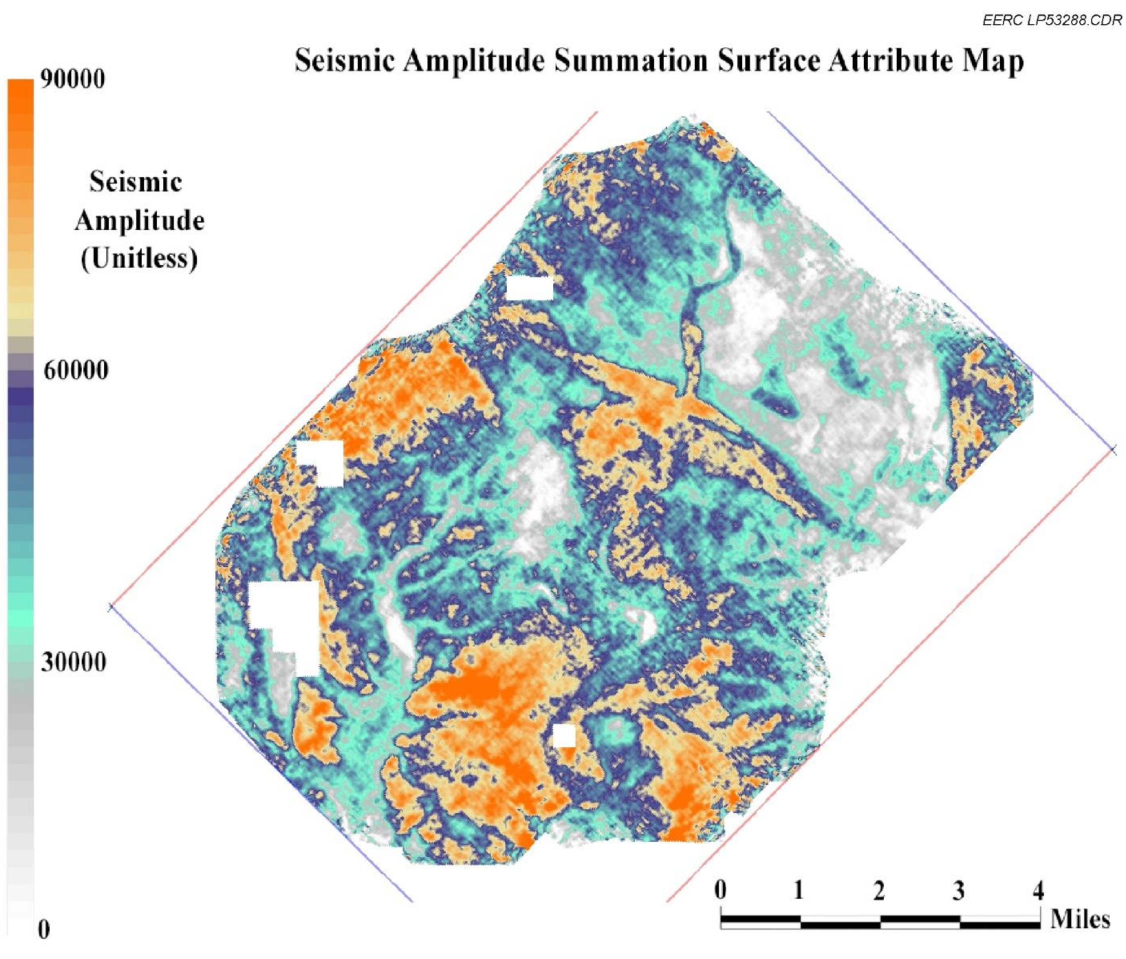

Figure 12. Seismic amplitude summation map for a thin, clastic reservoir used to understand heterogeneity prior to initiation of CO_2 injection.

Induced seismicity was a concern for local landowners. Deployment of passive seismic monitoring, through both surface and downhole instrumentation, detected limited microseismic activity of very small magnitude during operations, in common with experience from other dedicated storage projects. Contingency plans were available, had significant induced seismic been monitored, to investigate potential relationships with injection rates and associated pressures.

9.2 Case Study 2: Associated CO_2 Storage

This case study examined a scenario where a coal-based energy generation facility provided CO_2 for an EOR project over a 20-year period. The oil field, with a lengthy operational history dating back to the 1970s, had initial oil in place (OIP) estimated as 90 MMbbl. The field had progressed through primary recovery and secondary production (waterflooding), during which 8 MMbbl and 22 MMbbl of oil were produced, respectively, resulting in 30% recovery at the end of waterflooding. Recovery from CO_2 EOR would end up being 10.5 MMbbl for a total recovery of 45% at the end of the project and an estimated 5 Mt of CO_2 permanently stored at project conclusion.

Application of the AMA aimed to assure stakeholders that the operation would result in secure CO_2 storage within the reservoir, with no evidence of any adverse impacts to the environment.

9.2.1 Site Characterization

Assessment of associated storage potential benefitted from a wealth of existing data from numerous well penetrations (over 100 wells had been completed in the field with an 80-acre spacing). The field also contained older legacy wells, typically plugged and abandoned. The carbonate reservoir (limestone and dolostone) with subtle anticlinal structure was approximately 7000 feet below the ground surface. The reservoir was overlain by a thick sequence of evaporates, mainly anhydrite, providing an effective seal.

Existing subsurface data comprised well completion records, well logs, an interpreted 3-D seismic survey, downhole test results (pressure, temperature, permeability, and hydrocarbon productivity), and core sample descriptions and analyses. Additionally, a literature review yielded a portfolio of relevant publications for the site and revealed a host of other oil fields producing from the same carbonate formation. Collation of this extensive information, including operational data from primary and secondary production, allowed detailed characterization of the subsurface geology. As a result, fieldwork required for site characterization was limited to the collection of representative formation fluid samples (brine and hydrocarbons) and a small number of PNLs in production wells to further characterize and understand fluid saturations prior to CO_2 injection.

9.2.2 Modeling and Simulation

During project design, geologic modeling and numerical simulation of CO_2 injection provided an initial assessment of EOR performance and associated storage potential, assisted in the deployment of MVA technologies, and yielded actionable information to optimize field operation.

The existing network of wells provided the information needed to construct a structural framework and rock property distributions of the hydrocarbon-bearing formation and overlying seals with a high degree of confidence and thus limiting the need for uncertainty analysis. The initial geologic model, built with industry-standard software, extended beyond the field to avoid potential modeling edge effects. The model incorporated preinjection property distributions for facies/lithology, petrophysical properties (porosity and permeability), temperature, pressure, and fluid saturations. Other model inputs included well locations and characteristics, operational constraints (e.g., allowable injection rates and pressures), and dynamic variables such as relative permeability. History matching of primary and secondary production, enabled refinement of parameters such as permeability, relative permeability, and well performance.

The application of simulations to this case study further illustrates the relationship between CO_2 EOR and associated storage. From an operational perspective, simulations are essential to plan the optimization of incremental oil recovery and maximization of EOR effectiveness while minimizing CO_2 purchases to reduce cost. Simulations also allow forecasting of associated storage potential and long-term containment as constrained by the operational strategy. In the case study, simulations showed that water alternating gas (WAG) would offer optimal EOR performance, and this then allowed determination of associated storage potential. Of particular importance from an associated storage perspective, the overlying seal and anticlinal structure were forecast to securely contain injected CO_2.

9.2.3 Risk Assessment

The risk assessment for associated storage involved the same methodology employed in the case study for dedicated storage. However, the resulting risk profiles were markedly different, reflecting the greater confidence in the oilfield geologic model and assigned petrophysical properties. In common with associated storage assessments of typical CO_2 EOR projects, the most prominent technical risk scenario involved potential leakage of injected CO_2 through wellbores, including legacy plugged and abandoned wells in the field. Mitigation factors against this risk included a well recompletion program by the operator to facilitate the switch to CO_2 EOR operations and continued reservoir monitoring and surveillance.

9.2.4 MVA

Traditional reservoir surveillance techniques for CO_2 EOR focus on a cost-effective approach to reservoir and process management, typically including monitoring of wellhead temperatures and pressures, fluid flow rates (injection, production and recycling), fluid composition, and wellbore integrity. These reservoir surveillance techniques constitute a minimum set of requirements for associated storage assessment, with any additional requirements being determined by regulatory requirements and cost considerations. In this case study, the operator chose additional techniques to reassure local stakeholders and support verification and accounting to help monetize financial incentives for associated storage. The following specific objectives were defined for the monitoring program:

- Establish a baseline for reservoir and environmental conditions.
- Demonstrate that CO_2 is securely contained within the reservoir.

- Support the development and validation of reservoir simulation predictive models, providing confidence in long-term containment.

The monitoring plan included the following elements:

- Traditional reservoir surveillance
- Shallow environmental monitoring – groundwater and soil gas
- Downhole temperature and pressure
- Periodic PNL campaigns
- 4-D seismic surveys

4-D seismic surveys represent a relatively large investment for a CO_2 EOR project. The operator deemed that the ability of 4-D surveys to confirm CO_2 behavior and containment in the reservoir, combined with the added-value aspects of improved reservoir understanding to inform EOR operations, made that investment worthwhile.

Similar to Case Study 1, practical issues heavily influenced monitoring program design. The ground surface was moderately undulating, with steep hills in certain areas. A significant proportion of land belonged to ranch owners with livestock grazing. In addition to oil and gas wells, several shallow groundwater wells were important for consumption by local homeowners and ranchers. The local populace were generally supportive of the oil industry, but ranchers expressed concern at the prospect of additional oilfield activity disturbing grazing land and increased vehicular traffic, risking broken fences and loose livestock. Consequently, the monitoring program design minimized land access and disturbance issues as far as possible.

Soil gas monitoring focused on areas around existing wells (both active and legacy) since they provided the most likely pathways for potential CO_2 migration from the reservoir to the surface.

Downhole Pressure and Temperature Monitoring

A selected subset of active wells had pressure and temperature gauges in the reservoir, sealing formation, and selected overlying porous and permeable intervals to monitor for changes during operation. The resulting high acquisition frequency measurements enabled real-time monitoring of wellbore and reservoir conditions, providing the site operator confidence that the project was operating within normal limits. Any operational anomalies observed would have allowed initial diagnostics to investigate scaling, corrosion, and possible CO_2 leakage. Downhole pressure and temperature measurements also improved history matching and refinement of interpreted reservoir characteristics.

Pulsed-Neutron Logs

PNLs acquired during operation in selected wells provided a measure of CO_2 migration in the reservoir through measurement of near-wellbore fluid saturations, with preinjection baseline measurements providing reference data. PNLs also provided evidence of no out-of-zone CO_2

migration above the reservoir. Figure 13 shows an example of how PNL data can track the migration and accumulation of CO_2 adjacent to wells through time. PNL data can also be used to calibrate results from 4-D seismic surveys.

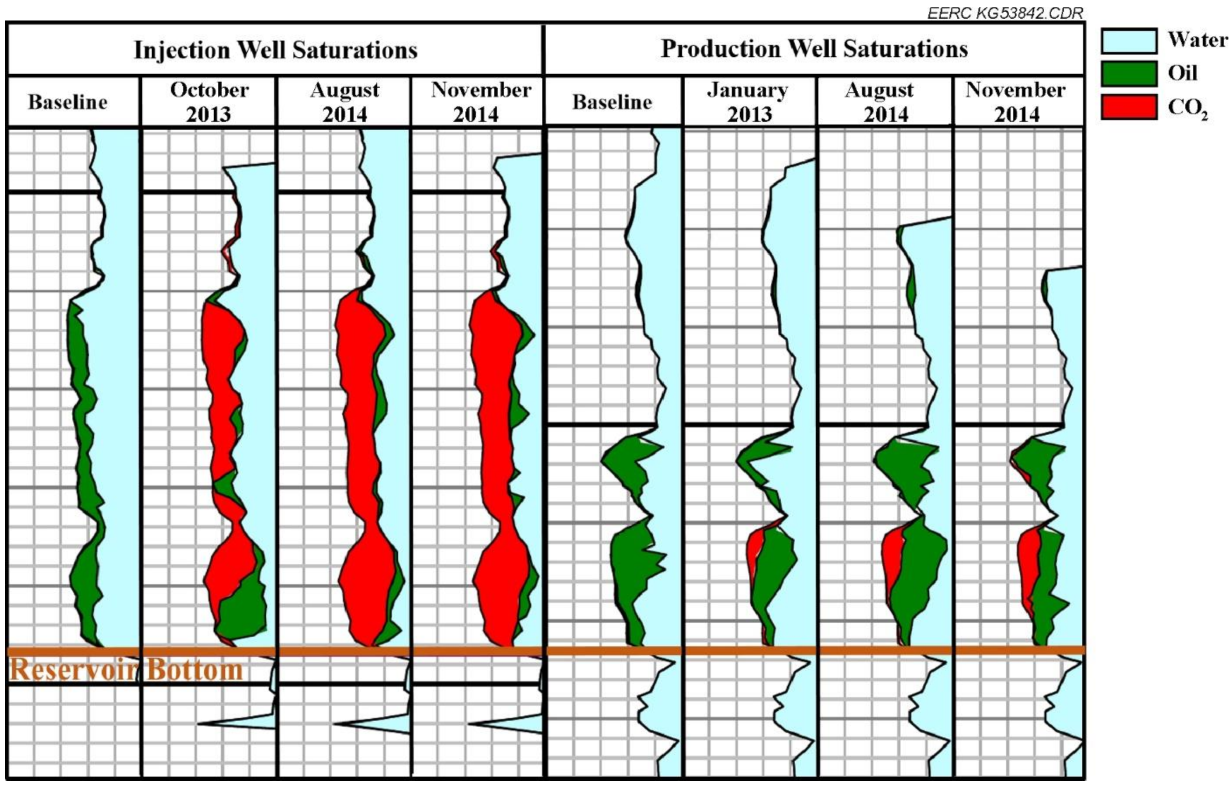

Figure 13. Time-lapse series of PNLs showing changes in fluid saturations in the reservoir interval between baseline and repeat campaigns for an injection well (left) and a production well (right).

Time-Lapse (4-D) Seismic Monitoring

The existing 3-D seismic survey acquired after the discovery of the field contributed to modeling and simulation of the field. However, the survey acquisition parameters were unsuitable as a baseline data set for operational monitoring.

To provide a long-term, cost-effective plan for the acquisition of 4-D seismic data while minimizing land disruption, the operator invested in a permanent seismic source and geophone array. The seismic source was placed near the center of the field on an engineered foundation and within an enclosure to minimize noise during acquisition and protect the equipment from weather. Burial of the array geophones several feet below the ground surface provided a safe and secure setup to protect against noise interference.

Acquisition of a baseline 3-D seismic survey with the permanent array, and repeat surveys during operations, allowed observation of changes in reservoir pressure and fluid saturation. These additional seismic data improved understanding of the structure and hydraulic characteristics of the reservoir. Figure 14 illustrates similar interpretations from repeat seismic surveys, with a map borrowed from a real CO_2 EOR project. This new understanding of the reservoir significantly improved the geologic model and predictive simulations. The improved predictions then provided a basis for revising the MVA strategy for the site as well as for conducting another site-specific risk assessment, which also helped guide additional MVA decisions.

A subset of the repeat PNL campaigns conducted in conjunction with seismic data acquisition supplemented the information from both data sets. Time-lapse (4-D) seismic investigations identified locations where the combined effects of changes in fluid saturations and pressure occurred. However, the differences noted were difficult to parse in terms of understanding the contribution of each to the result. The PNLs provided known fluid saturation conditions at a handful of locations, enabling estimation of the impact of changing fluid saturations on the observed time-lapse seismic differences. This information enabled better understanding of the seismic results, especially the observed differences between wells.

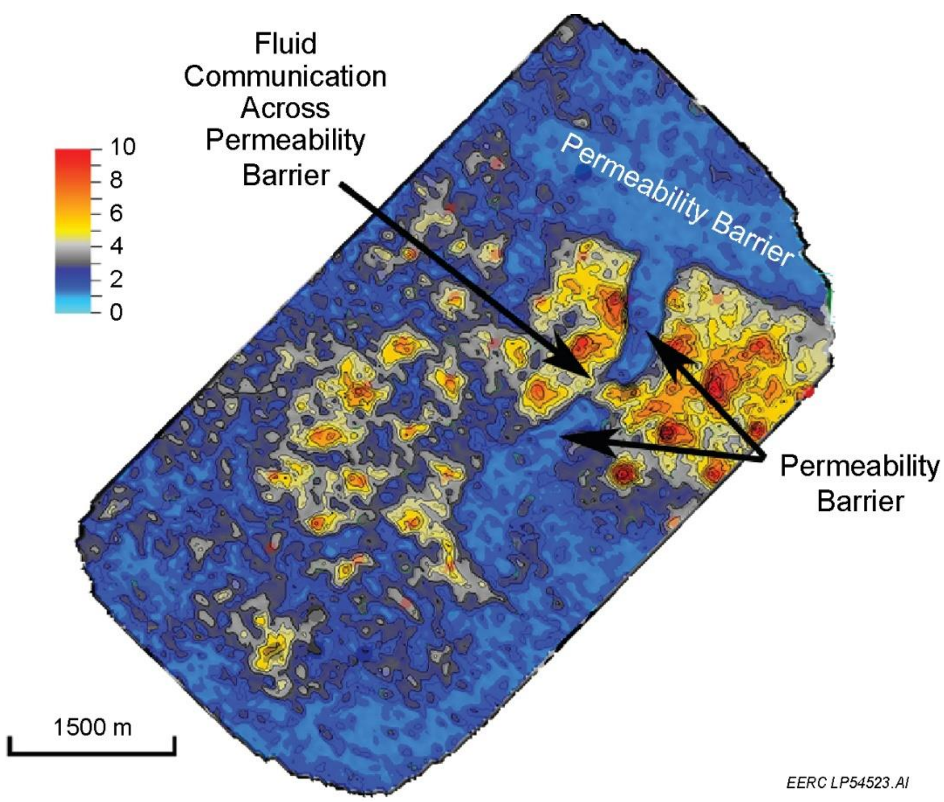

Figure 14. Example 4-D difference seismic amplitude map, taken for illustrative purposes from a real CO_2 EOR project. Warmer colors represent greater difference in amplitude between baseline and repeat seismic surveys, attributed to changes in pressure and CO_2 saturation within the reservoir because of injection. Cooler colors represent little change in reservoir pressure and fluid saturation between baseline and repeat seismic surveys.

9.3 Case Study Highlights

The two case study scenarios presented hypothetical storage projects; however, the AMA technical activities included and the challenges noted were based upon actual storage projects in the PCOR Partnership region. Overarching messages illustrated by these case studies include the following:

- Similar geologic characterization information is required for both dedicated and associated storage projects. However, site characterization efforts are generally more challenging in dedicated storage scenarios, stemming from the absence of prior commercial exploitation (e.g., few existing well penetrations, seismic surveys, geologic core samples for the formation of interest).

- Site characterization efforts directly support the other AMA technical elements, providing direct inputs during geologic model construction, assisting in determining effective types of monitoring techniques and appropriate placement, and highlighting data gaps, which may lead to increased subsurface technical risk.

- Modeling and simulation activities for both dedicated and associated storage projects are conducted to support the containment of injected CO_2 within the zone of interest (injection formation) and AOR. Modeling and simulation for associated storage projects have an additional focus of providing information needed to improve the economic outlook of the primary commercial driver (i.e., hydrocarbon production).

- Technical uncertainty translates to risk. Identified risks can guide further simulation activities accounting for a range of possible scenarios with the desired confidence intervals (i.e., uncertainty analyses resulting in a range of realizations, from conservative to optimistic) to investigate the likelihood and impact of specific risks.

- Uncertainty analyses conducted on geologic models are important for typical dedicated storage scenarios. If prior operational data are available (i.e., operational data from an oil field having undergone primary and secondary production), history matching can be undertaken to increase the accuracy of simulation models and their ability to give accurate predictive results.

- Risk assessment provides the means to determine the suitability of a storage complex as it relates to both technical and nontechnical considerations. Identified risks may guide additional data acquisition, modeling, and simulation and assist in tailoring a monitoring program to evaluate and mitigate those risks throughout project operation.

- Through the risk assessment process, evaluation of project risks will yield information needed to plan, adapt/modify, or discontinue project activities in the interest of environmental health and human safety.

- Characterization data may provide a basis for establishing baseline conditions and subsequent comparisons with operational monitoring, subject to data quality and related issues.

- A fit-for-purpose MVA program will directly support risk assessment and reduction. Identified risks drive monitoring technology implementation, and the operational monitoring data generated provide confidence that storage projects proceed as intended and enable rapid identification of unintended consequences needing further investigation and/or remediation.

- Finally, a topic not expounded on in the case studies but worth mentioning briefly is postclosure monitoring (e.g., monitoring pressure dissipation in the storage formation). Postclosure requirements, including the type of monitoring activities and duration of implementation, for each type of operation (dedicated and associated storage) would be governed by operational performance, risks remaining at project conclusion, and regulatory requirements.

Referring back to the PCOR Partnership AMA, all of the bullets above demonstrate the interconnected nature of the four technical elements upon which the approach is focused. Through this process, new information brought forth by any of these four technical elements can be used to enhance the others, contributing positively to the potential for success over the course of a storage project.

CHAPTER 10: CONCLUSION

CCUS can play a major role in wider efforts to manage carbon and mitigate greenhouse gas emissions. Significant CCUS activity is happening in the PCOR Partnership region as well as the remaining portions of the United States and Canada. However, successful development and operation of thousands of commercial-scale CCUS projects around the globe will be required to abate CO_2 emissions from power production and industrial sources within the coming decades. The large-scale deployment of CCUS technologies depends upon their becoming accepted, trusted, economical, and conventional technologies. A rigorous and systematic approach to storage project planning, design, and operation to support CCUS deployment is the intent for the PCOR Partnership AMA.

PCOR Partnership efforts have demonstrated fit-for-purpose applications of the AMA for both dedicated and associated storage projects. Integration and execution of each of the four technical elements included in the AMA enable efficient gathering and assessment of site-specific data needed to 1) provide fundamental understanding of a potential storage complex, 2) predict and assess performance, and 3) demonstrate safe and successful operation. Readers interested in learning more are encouraged to access the PCOR Partnership best practices manuals below:

1. Best Practice for the Commercial Deployment of Carbon Dioxide Geologic Storage: The Adaptive Management Approach (Ayash and others, 2016)

2. Best Practices Manual for Site Characterization (Glazewski and others, 2017)

3. Best Practices for Modeling and Simulation of CO_2 Storage (Bosshart and others, 2018)

4. PCOR Partnership Best Practices Manual for Subsurface Technical Risk Assessment of Geologic CO_2 Storage Projects (Azzolina and others, 2017)

5. Best Practices Manual – Monitoring for CO_2 Storage (Glazewski and others, 2018)

As one of the RCSPs, the PCOR Partnership assisted in the development of DOE NETL BPMs containing lessons learned and best practices for projects under DOE's Carbon Storage Program. DOE NETL RCSP BPMs can be found at www.netl.doe.gov/coal/carbon-storage/strategic-program-support/best-practices-manuals. The first editions were completed in 2010, and five BPMs were updated in 2017 to include new information learned in the RCSP development phase field projects. The seven DOE BPMs are as follows:

1. Geologic Formation Storage Classification (U.S. Department of Energy National Energy Technology Laboratory, 2010a)

2. Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects (U.S. Department of Energy National Energy Technology Laboratory, 2017c)

3. Public Outreach and Education for Geologic Storage Projects (U.S. Department of Energy National Energy Technology Laboratory, 2017a)

4. Risk Management and Simulation for Geologic Storage Projects (U.S. Department of Energy National Energy Technology Laboratory, 2017d)

5. Operations for Geologic Storage Projects (U.S. Department of Energy National Energy Technology Laboratory, 2017e)

6. Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects (U.S. Department of Energy National Energy Technology Laboratory, 2017b)

7. Terrestrial Sequestration of CO_2 (U.S. Department of Energy National Energy Technology Laboratory, 2010b)

For more information, the public PCOR Partnership Web site (www.undeerc.org/pcor) contains a wealth of information related to CCUS geared toward various audiences.

To learn more about the PCOR Partnership and its activities, contact:

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018
(701) 777-5000
www.undeerc.org

REFERENCES

American Carbon Registry, 2015, http://americancarbonregistry.org/carbon-accounting/standards-methodologies/carbon-capture-and-storage-in-oil-and-gas-reservoirs/acr-ccs-methodology-v1-0-final.pdf.

Ayash, S.C., Nakles, D.V., Peck, W.D., Sorensen, J.A., Glazewski, K.A., Aulich, T.R., Klapperich, R.J., Azzolina, N.A., and Gorecki, C.D., 2016, Best practice for the commercial deployment of carbon dioxide geologic storage—adaptive management approach: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 13 Deliverable D102/Milestone M59 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-05-01, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

Azzolina, N.A., Nakles, D.V., Ayash, S.C., Wildgust, N., Peck, W.D., and Gorecki, C.D., 2017, PCOR Partnership best practices manual for subsurface technical risk assessment of geologic CO_2 storage projects: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 13 Deliverable D103 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

Azzolina, N.A., Nakles, D.V., Ayash, S.C., Wildgust, N., Peck, W.D., and Gorecki, C.D., 2017, PCOR Partnership best practices manual for subsurface technical risk assessment of geologic CO_2 storage projects: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 9 Deliverable D103 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-10-21, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

Bosshart, N.W., Pekot, L.J., Wildgust, N., Gorecki, C.D., Torres, J.A., Jin, L., Ge, J., Jiang, T., Heebink, L.V., Kurz, M.D., Dalkhaa, C., Peck, W.D., and Burnison, S.A., and 2018, Best practices for modeling and simulation of CO_2 storage: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 9 Deliverable D69 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2018-EERC-03-13, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

Canadian Standards Association, 2012, Z741-12 – geological storage of carbon dioxide.

Det Norske Veritas, 2013, Geological storage of carbon dioxide.

Glazewski, K.A., Aulich, T.R., Wildgust, N., Nakles, D.V., Azzolina, N.A., Hamling, J.A., Burnison, S.A., Livers-Douglas, A.J., Peck, W.D., Klapperich, R.J., Sorensen, J.A., Ayash, S.C., Gorecki, C.D., Steadman, E.N., Harju, J.A., Stepan, D.J., Kalenze, N.S., Musich, M.A., Leroux, K.M., and Pekot, L.J., 2018, Best practices manual – monitoring for CO_2 storage: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 9 Deliverable D51 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2018-EERC-03-15, Grand Forks, North Dakota, Energy & Environmental Research Center, March.

Glazewski, K.A., Aulich, T.R., Wildgust, N., Nakles, D.V., Hamling, J.A., Burnison, S.A., Livers, A.J., Salako, O., Sorensen, J.A., Ayash, S.C., Pekot, L.J., Bosshart, N.W., Gorz, A.J., Peck, W.D., and Gorecki, C.D., 2017, Best practices manual (BPM) for site characterization: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 4 Deliverable D35 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-06-08, Grand Forks, North Dakota, Energy & Environmental Research Center, March.

Glazewski, K.A., Aulich, T.R., Wildgust, N., Nakles, D.V., Hamling, J.A., Burnison, S.A., Livers, A.J., Salako, O., Sorensen, J.A., Ayash, S.C., Pekot, L.J., Bosshart, N.W., Gorz, A.J., Peck, W.D., and Gorecki, C.D., 2017, Best practices manual (BPM) for site characterization: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 4 Deliverable D35 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-06-08, Grand Forks, North Dakota, Energy & Environmental Research Center, March.

Global CCS Institute, 2017, www.globalccsinstitute.com/projects (accessed 2017).

Gorecki, C.D., Hamling, J.A., Klapperich, R.J., Steadman, E.N., and Harju, J.A., 2012, Integrating CO_2 EOR and CO_2 storage in the Bell Creek oil field, *in* 2012 Carbon Management Technology Conference, Orlando, Florida, February 7–9, 2012, Proceedings: CMTC 151476.

IEA Greenhouse Gas R&D Programme, 2009, CCS site characterization criteria: 2009/10, July.

International Organization for Standardization, 2009, Risk management—principles and guidelines: ISO 31000:2009(E).

Oil and Gas Journal, 2014, 2014 worldwide EOR survey: www.ogj.com/articles/print/volume-112/issue-4/special-report-eor-heavy-oil-survey/2014-worldwide-eor-survey.html (accessed May 2019).

Peck, W.D., Glazewski, K.A., Klenner, R.C.L., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2014, A workflow to determine CO_2 storage potential in deep saline formations: Energy Procedia, v. 63, p. 5231–5238.

Peck, W.D., Battle, E.P., Grove, M.M., and Glazewski, K.A., compilers and creators, 2016, Plains CO_2 Reduction (PCOR) Partnership atlas, 5th ed.: Prepared for the U.S. Department of Energy National Energy Technology Laboratory and the PCOR Partnership, Grand Forks, North Dakota, Energy & Environmental Research Center.

Project Management Institute, 2008, A guide to the project management body of knowledge (PMBOK guide): Newtown Square, Pennsylvania: Project Management Institute.

Quintessa, 2014, Generic CO_2 FEP database, Version 2.0: Quintessa Limited, Henley-on-Thames, United Kingdom. Open access on-line database www.quintessa.org/co2fepdb/.

U.S. Department of Energy National Energy Technology Laboratory, 2010a, Best practices for—geologic formation storage classification: 2017-1420.

U.S. Department of Energy National Energy Technology Laboratory, 2010b, Best practices for—terrestrial sequestration of CO_2.

U.S. Department of Energy National Energy Technology Laboratory, 2012. Carbon sequestration atlas of the United States and Canada (4th ed.).

U.S. Department of Energy National Energy Technology Laboratory, 2017a, Best practices—public outreach and education for geologic storage projects [2017 rev. ed.]: 2017-1845.

U.S. Department of Energy National Energy Technology Laboratory, 2017b, Best practices—monitoring, verification, and accounting (MVA) for geologic storage projects [2017 rev. ed.]: 2017-1847.

U.S. Department of Energy National Energy Technology Laboratory, 2017c, Best practices—site screening, site selection, and site characterization for geologic storage projects [2017 rev. ed.]: 2017-1844.

U.S. Department of Energy National Energy Technology Laboratory, 2017d, Best practices—risk management and simulation for geologic storage projects [2017 rev. ed.]: 2017-1846.

U.S. Department of Energy National Energy Technology Laboratory, 2017e, Best practices—operations for geologic storage projects [2017 rev. ed.]: 2017-1848.

U.S. Environmental Protection Agency, 2010a, Mandatory reporting of greenhouse gases: injection and geologic sequestration of carbon dioxide—final rule: Federal Register, v. 75, no. 230, at 75060, December 1.

U.S. Environmental Protection Agency, 2010b, Federal requirements under the underground injection control (UIC) program for carbon dioxide geologic sequestration wells—final rule: Federal Register, v. 75, no. 237, p. 77266–77267, December 10.